



Karish and Tanin Field Development Plan

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ABBREVIATION	DEFINITION
ACQ	Annual Contracted Quantity
ALARP	As Low as Reasonably Practicable
API	American Petroleum Institute
bbls	Barrels
BCF	Billion Cubic Feet
BOPD	Barrels of Oil Per day
BS&W	Basic sediment and water
BTU/SCM	British Thermal Unit per Standard Cubic Meter
BWPD	Barrels of Water Per Day
CCR	Central Control Room
CGR	Condensate Gas Ratio
COW	Crude Oil Wash
CRP	Control and Riser Platform
DNV	Det Norsk Veritas
EERA	Emergency Escape, Evacuation and Rescue Assessment
E&P	Exploration and Production
EPCIC	Engineering Procurement Construction Installation Commissioning
EPU	Electric Power Unit
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
ESSA	Emergency System Survivability Assessment
EWS	Engineering Workstation
FEED	Front End Engineering Design
FERA	Fire and Explosion Risk Assessment
FGS	Fire and Gas System
FORJ	Fibre Optic Rotary Joint
FPSO	Floating Production, Storage and Offloading vessel

ABBREVIATION	DEFINITION
FW	Fire Water
FWG	Fresh Water Generator
GDU	Gas Dehydration Unit
GTL	Gas Trunk Line
HAZID	Hazard Identification study
HAZOP	Hazard and Operability study
HC	Hydrocarbon
HMI	Human Machine Interface
HP	High Pressure
HPU	Hydraulic Power Unit
HSE	Health, Safety and Environment
HUC	Hook-up and Commissioning
ICSS	Integrated Control and Safety System
IDF	Israeli Defence Force
IGS	Inert Gas System
IMO	International Maritime Organisation
INGL	Israeli Gas Distribution Grid
I/O	Input/Output
ISD	Inherently Safer Design
ISO	International Organisation for Standardisation
IVB	Independent Verification Body
JT	Joule Thomson
KO	Knock Out
LCC	Life Cycle Cost
LEL	Lower Explosive Limit
LOPA	Layer of Protection Analysis
LP	Low Pressure

ABBREVIATION	DEFINITION
LQ	Living Quarters
LTS	Low Temperature Separator
LVSR	Low Voltage Slip Ring
MARPOL	International Convention for the Prevention of Pollution from Ships
MCC	Motor Control Centre
MCS	Master Control System
MDQ	Mean Daily Quantity
MMBO	Million Barrels of Oil
MMBW	Million Barrels of Water
Mmscf/day	Million Standard Cubic Meters per Day
MP	Medium Pressure
NFPA	National Fire Protection Association
NORSOK	Norwegian Technology Centre
OPEX	Operating Expenditure
OT	Onshore Terminal
PA	Public Address
PCHE	Printed Circuit Heat Exchanger
PCS	Process Control System
PFP	Passive Fire Protection
PLC	Programmable Logic Controller
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
PNGRB	Petroleum and natural Gas Regulatory Board
POB	Personnel on Board
PPE	Personnel Protective Equipment
ppm	Parts Per Million
PSD	Process Shutdown

ABBREVIATION	DEFINITION
PSV	Pressure Safety Valve
Q	Quarter
QRA	Quantitative Risk Assessment
RAM	Reliability Availability and Maintenance report
RBM	Riser Base Manifold
RIB	Rigid Inflatable Boat
SCS	Subsea Control System
SD	Shutdown
SDU	Subsea Distribution Unit
SPE	Society of Petroleum Engineers
SOLAS	Safety of Life at Sea
SSP	Ship Security Plan
Stb/mmscf	Stock Tank Barrels per Million Standard Cubic Feet
STD	Standard
STP	Submerged Turret Production
TEG	Tri-ethylene Glycol
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
TR	Temporary Refuge
TUTU	Topside Umbilical Termination Unit
TVP	True Vapour Pressure
UN	United Nations
UPS	Uninterruptible Power Supply
UV	Ultraviolet
VAC	Ventilation and Air Conditioning
WGFM	Wet Gas Flow Meter

1 Management Summary

1.1 Description of the hydrocarbon reservoirs, development strategy, facilities and pipelines

This Field Development Plan (FDP) covers the development of the Karish and Tanin fields which are located between 75 and 120km offshore the northern coast of Israel in water depths of approximately 1750m. The Karish Main field, within the Karish Lease, was discovered in 2013 and lies some 25km north-east of Noble Energy's Tamar field development. The Tanin Block A, B and C fields in the Tanin Lease were discovered in 2012. The Tanin mega-complex forms a northern extension of the super-giant Leviathan field that is currently being developed by Noble Energy. All discovered hydrocarbon accumulations contain sweet, lean, gas and associated liquids in high-quality, stacked, sands within the lower Miocene formation. The Karish C reservoir contains significantly more hydrocarbon liquids than the other discovered reservoirs. Separate exploration and production Leases have been granted over the two discoveries. These Leases were finalized and approved on April 25th 2017 and expire August 2044. 10-year extensions are allowed for in the Leases.

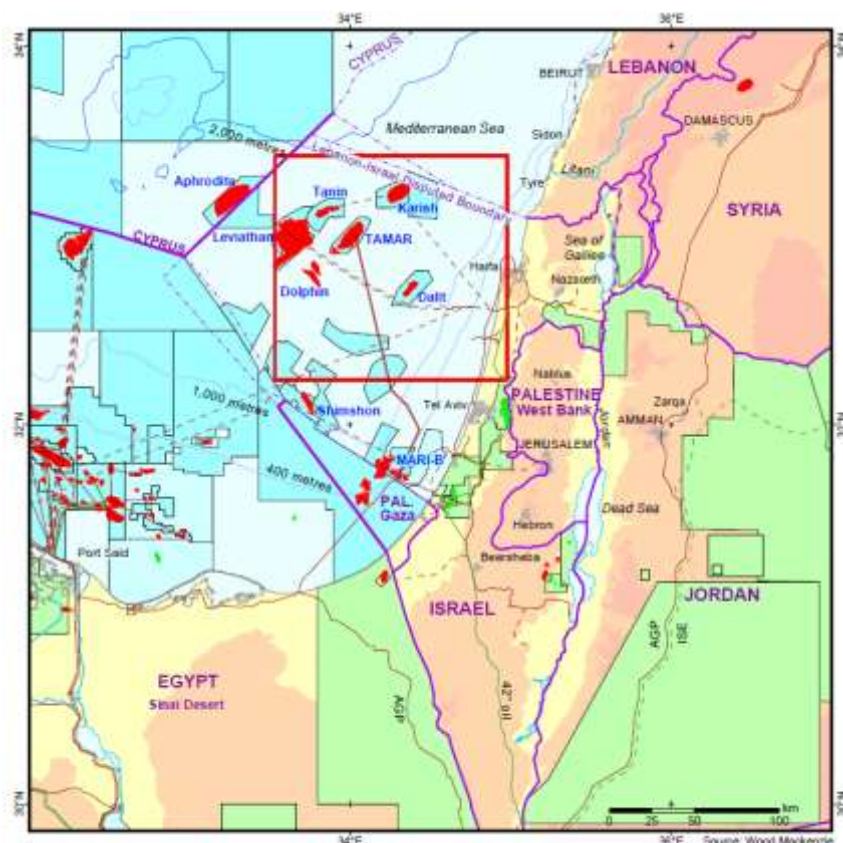


Figure 1-1 Regional location of Karish and Tanin Leases

In addition to the discovered Karish Main field the Karish Lease contains numerous leads and prospects at multiple horizons. Similarly the Tanin Lease also contains significant yet-to-be drilled exploration potential (Blocks D, E and F in the Lease itself as well as segments of other accumulations that may close outside the Lease area). In addition to describing the development of the existing discoveries this FDP also indicates how additional discoveries would be accommodated and the potential impact such discoveries could have on the phased development timeline currently envisaged.

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The following maps, prepared by Energean from the 3D seismic shot by Noble Energy, identify and name the discoveries, prospects and leads in each Lease at the lower Miocene level.

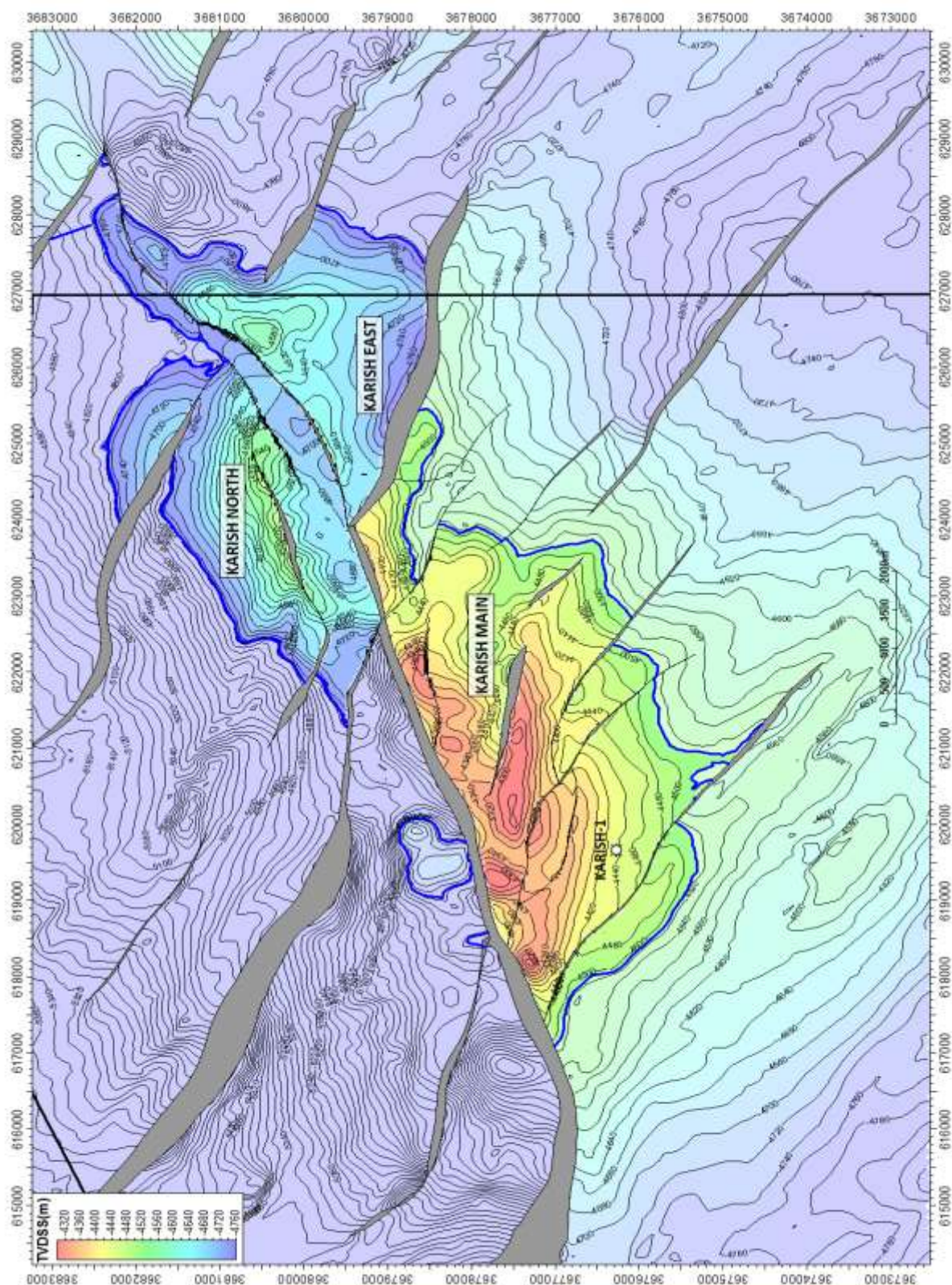


Figure 1-2 Hydrocarbon accumulations in the Lower Miocene Karish Lease

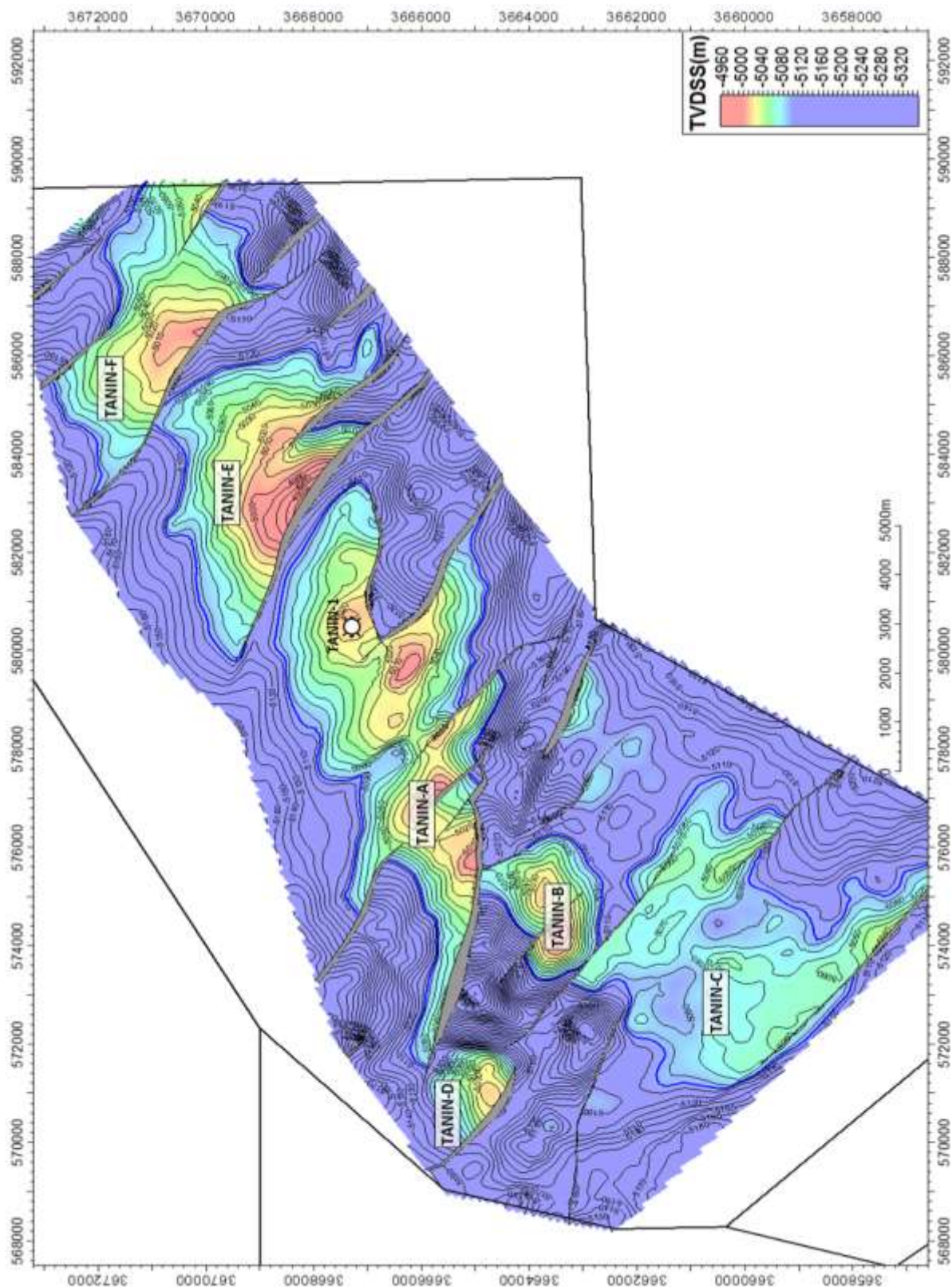


Figure 1-3 Hydrocarbon accumulations at the Lower Miocene level Tanin Lease

1.1.1 Exploration history and reservoir description

The Tanin-1 well was spudded on the 9th December 2011 and was drilled to a total depth, sub-sea, of 5504m in what is now referred to as the Tanin-A Block. It discovered gas saturated Tamar A and B sands and proved up gas volumes in the connected Tanin B and Tanin C Blocks (see Figure 1-3). The sands appear to be in communication and from pressure data share a Gas Water Contact (GWC) at 5091m. The penetrated structure is filled to the mapped spill point. Reservoir pressure was approximately 610 bar. Reservoir properties determined from log and side-wall core data indicate the sands are analogous to those discovered in the Tamar and Leviathan fields. When the reservoir fluids are processed to provide sales specification gas and liquid, approximately 5 bbls of light oil will be generated for every million standard cubic feet of gas. Within the Tanin Lease three additional structures at the Lower Miocene level have been identified from available 3D seismic. A number of other structures likely close outside the Lease. These have not been considered in this FDP.

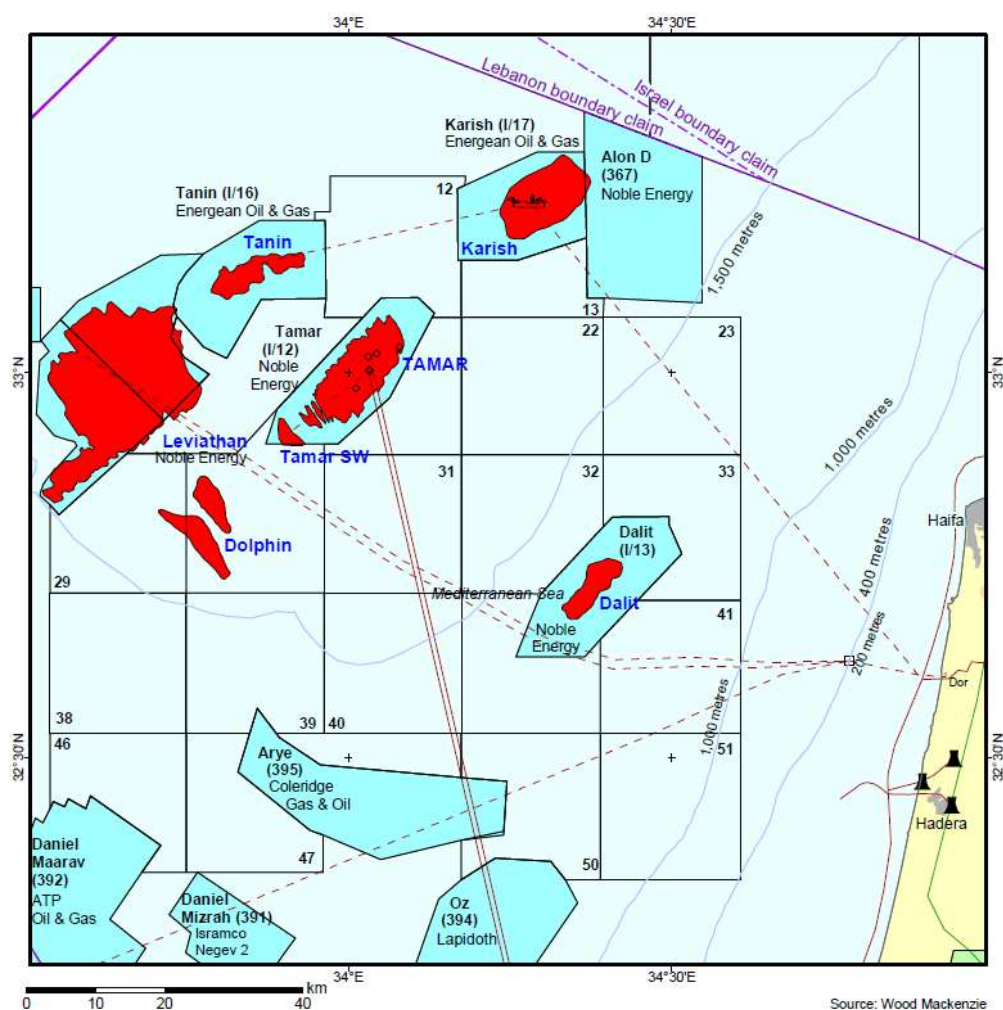


Figure 1-4 Location of Karish and Tanin Leases

The Karish-1 well was spudded on 21st March 2013 and was drilled to a total depth, sub-sea, of 4812m in what is now called the Karish Main accumulation. It discovered gas saturated Tamar B and C sands. These sands appear to be in communication. A GWC was penetrated in the C reservoir at 4512m. From measured pressure data a similar contact is predicted in the B sands. Reservoir pressure in the C sand was approximately 550 bar. The structure is not filled to the mapped spill point. Initial evaluations concluded that additional thin sands in the A horizon had been discovered with these sands sitting on a slightly elevated pressure gradient. Following detailed seismic interpretation it is now concluded that in the vicinity of the discovery well the A sands have

been eroded and the resultant “scour” in-filled with younger sediments. Logged gas in the A interval is associated with isolated, gas-filled, sand-stringers within this younger material. These erosional events have been mapped in detail. On the flanks of the structure away from these eroded areas there is good potential to find gas in currently unpenetrated A-horizon sands. It is currently assumed that these A-sand reservoirs would share a GWC with both the B and C reservoirs. The gas in the penetrated “stringers” is at a slightly elevated pressure likely due to uplift subsequent to their being charged.

Sands in the B horizon are thin and heavily laminated. However, these can be identified clearly on available image logs. Conventional logging tools (as used by Noble during the Karish-1 evaluation) are unable to accurately measure the properties of these sand bodies instead providing average readings over the sand and shale layers. Consequently initial work undertaken by Noble and partners significantly underestimated gas volumes in this horizon. Side wall core data demonstrated that these thin sands have similar porosities and gas saturations as the much blockier sands found in the upper parts of the C interval that will be the initial development target in the Karish Main field. A full, state-of-the-art, thin-sand, petrophysical evaluation has been completed and used to assess B-sand resources. The B-sand at Karish Main is the largest sub-surface uncertainty in this FDP and represents a significant upside that will be fully quantified during the development of the C/D reservoirs.

Good quality sands were also discovered below the gas water contact in the D interval. In Tamar this interval is gas bearing at the crest of the field and shares a common contact with the A, B and C horizons. In Karish Main the D reservoir is also mapped as being above the identified contact at the structural high. Detailed mapping shows that the C and D reservoirs are juxtaposed across numerous faults. Fault seal analysis based on shale-gouge ratios concluded that these faults should not seal and hence gas will also be present in the Karish Main D reservoir and will be produced along with volumes in the C horizon. D sands have similar reservoir properties to those in the C horizon.

The fluid in the Karish C reservoir is substantially richer than that discovered in the other Levantine basin fields (Tanin, Tamar, Leviathan etc.). When the reservoir fluids are processed to gas and liquid sales specifications some 20 - 24 bbls of a light oil (or heavy condensate) will be created per million standard cubic foot of gas. This is almost five times as much as in Tanin. Energean has used a CGR of 22 in its definition of a “best technical case” based upon extensive PVT analysis.

The following table summarizes the key reservoir properties of the Karish Main and Tanin A, B and C block discoveries.

Table 1-1: Karish and Tanin key reservoir properties

KARISH MAIN					
	GRV MMm ³	NTG Decimal	Net PHIT Decimal	Net Sgas Decimal	Bg SCM/RCM
A Sands	682	0.22	0.22	0.61	364
B Sands	1418	0.38	0.20	0.60	363
C Sands - Upper	601	0.93	0.24	0.83	357
C Sands - Lower	634	0.50	0.20	0.75	357
D Sands	259	0.65	0.22	0.74	361

TANIN A					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	Mm ³	Decimal	Decimal	Decimal	SCMRCM
A Sands	465.6	0.81	0.23	0.70	364
B Sands	149.1	0.66	0.22	0.70	363
TANIN B					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	Mm ³	Decimal	Decimal	Decimal	SCMRCM
A Sands	73.7	0.84	0.22	0.70	364
B Sands	24.4	0.70	0.21	0.70	363
TANIN C					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	Mm ³	Decimal	Decimal	Decimal	SCMRCM
A Sands	269.4	0.84	0.23	0.70	364

1.1.2 Development Strategy

Detailed reservoir and facility studies have been undertaken over the last 12 months, assessing a range of development scenarios taking into account uncertainties in reservoir size and performance (particularly strength of aquifer), facility type and location, development phasing, current gas-market capacity, gas-market growth potential and liquid disposition point. Value drivers were defined and used to rank the large number of potential development scenarios identified. This process (see section 7 for details) generated an optimum development plan as summarised below:

- A phased development approach will be followed. The Karish Main field will be developed first. Tanin A, C and B blocks (and any exploration discoveries made following the Karish Main development within the Karish and Tanin Leases) will be tied back subsequently to the Karish facilities. Karish Main was selected as the initial development as it is the largest discovery, provides the highest yield of liquid per volume of produced gas and is the closest discovery to shore,
- A new-build, spread-moored FPSO will be located immediately south of the Karish Main field in approximately 1700m water depth.
- Three development wells will be drilled initially in the Karish Main field and tied back to the FPSO. One well will be located in each of the three mapped fault blocks close to local structural highs. These three new Karish Main development wells will be drilled deviated from a central location with a maximum offset of less than 1.2 km and angle less than 42°. The existing exploration well will not be re-entered and sidetracked. The wells will be completed in the C reservoir with an OHGP. Well positions have been optimised to provide good sweep of both the C and D zones. The D reservoirs are drained through communicating faults. Two scenarios for B sand production have been examined and are represented in the FDP as two alternative cases (see below for details).
- A production manifold will be located immediately south of the well cluster and will include a spare slot for a Karish North discovery well or to enable an additional multi-slot manifold to be accommodated. The Karish Main manifold is designed to allow it to be extended should dedicated Karish Main A and/or B reservoir wells be justified at a later date. Karish North could also be tied back via this route if dual flowlines from a larger discovery/development are desirable.
- The Tanin A, C and B blocks would be developed (in this order) after the Karish Main field. The exact date will depend on the rate of gas extraction (sales) from Karish Main and the pressure support provided by the underlying aquifer. It is also possible that other discoveries closer to the

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Karish FPSO would be developed before the Tanin discoveries. The initial Tanin development would consist of 3 wells in the A block tied back via a new manifold and a 40km long multi-phase production system to the Karish FPSO. The existing Tanin exploration well will not be reused. It is anticipated that the prospects in the NE part of the Lease would be explored/appraised prior to the development of Tanin to ascertain the total volume of resources in the Lease. A full development of the Tanin Lease may require up to 8 wells to be drilled eventually. After the A block, the C block would be developed with 2 wells and finally the B block with a single well. Although the volumes in the B block are small, a single well and tie back to an existing sub-sea system was shown to be commercial. It should be noted that in the economic case included in this FDP the 2nd C Block well and the development of the B Block are excluded (both costs and production) as at a flat 3 BCM/year production rate, and with the calculated in-place volumes, their associated gas volumes would be produced after November 2044 (end of the Lease) and hence are not captured in the presented economics. In reality Energean expects these wells would be drilled and the Lease extended, particularly if exploration wells have led to further discoveries. The Tanin E and F block prospects are the most attractive targets in the Tanin Lease from a development perspective and would be accelerated ahead of Blocks A and C if discovered. This would reduce the number of wells drilled in the Lease period. Any exploration wells drilled would be designed so they can be used as development wells considering the high POS calculated for these prospects.

- The FPSO will process fluids produced from the Karish field, and later other nearby discoveries and eventually the fluids from Tanin. Three streams will be created:
 - dry gas to INGL pipeline specification;
 - a mixed oil/condensate stream stabilized to tanker specification;
 - Hydrocarbon-free water.
- The FPSO will be developed with a design life of 35 years to ensure that it remains operable through to end of the available 10-year Lease extension period (November 2054),
- Dry gas will be transported to the Israeli coast (Dor beach) via a new build, 90km, 24"/30" outside diameter pipeline. This pipeline will leave the FPSO with a 24" diameter and increase in diameter approximately 15km from shore to 30". An "interface facility" will be included in the dry-gas pipeline at a distance of 10 km from the Israeli coast. This will consist of a full-bore, inline ball valve equipped with a valved T-piece upstream and downstream. This will enable 3rd party gas to be accommodated in the near-shore and onshore sections of the pipeline at a point in the future when other smaller fields are developed. INGL will install a manifold and tie it into these valved T-pieces at that time.
- The last 10km of the offshore dry-gas pipeline and the onshore section will be owned by INGL and funded by the Israeli government. The costs and economics included in this FDP however assume the whole line will be funded by Energean. Energean envisages modifying its budget when the magnitude of government funding for this section of the dry gas line is confirmed.
- A light-oil/condensate blend (approximately API 50) will be stored on the FPSO (up to 800,000 bbls of crude storage is available) and then transferred to tankers offshore and exported. 7 loadings per year are envisaged.
- De-oiled produced water will be stored for a number of years before being discharged to sea.
- The FPSO will generate its own power using either flash gas from the oil train or gas taken from the export line.
- The FPSO will be designed to satisfy all security requirements of the Israeli Ministry of Defense.

In parallel with performing necessary technical studies, Energean has actively engaged with gas buyers in Israel to determine the potential demand for Karish gas by 2020 and the likely growth in demand following this production start-date. Based on this work it has been decided that the Integrated Production System outlined above will have an initial peak capacity of slightly more than 400 mmscf/day. This will allow annual gas sales of between 3 and 4 BCM/year to be achieved. By using a spread moored FPSO equipped with spare real-estate, the capacity can later be expanded as local market demand grows. A maximum capacity of between 600 and 800,000 mmscf/day is envisaged. For this FDP it has been assumed that Energean successfully sells

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3 BCM/year of gas and that it maintains production at this rate until all discovered, commercial resources are produced. This means that the production plateau extends beyond the end of the primary Lease period. Presented economics are cut-off at November 2044. 3 BCM/year is considered the minimum gas sales rate at which the Karish and Tanin development project would be sanctioned by Energean. All economics presented in this FDP are based upon this 3 BCM/year, gas sales rate.

The dry-gas pipeline linking the new build FPSO to Dor will be designed such that following expansion, peak rates of some 800 mln scf/day of gas can be transported to the INGL transmission system. Initial capacity of the installed 24"/30" line will be > 650 mln scf/day. This will be expanded by adding a second riser. These capacities take into consideration gas from 3rd party suppliers accessing the INGL owned section of the dry-gas pipeline. The FPSO will initially be equipped with a single process train of nominal capacity 400 mln scf/day. A second identical train could be added to double capacity.

The following figure illustrates the initial development scheme.

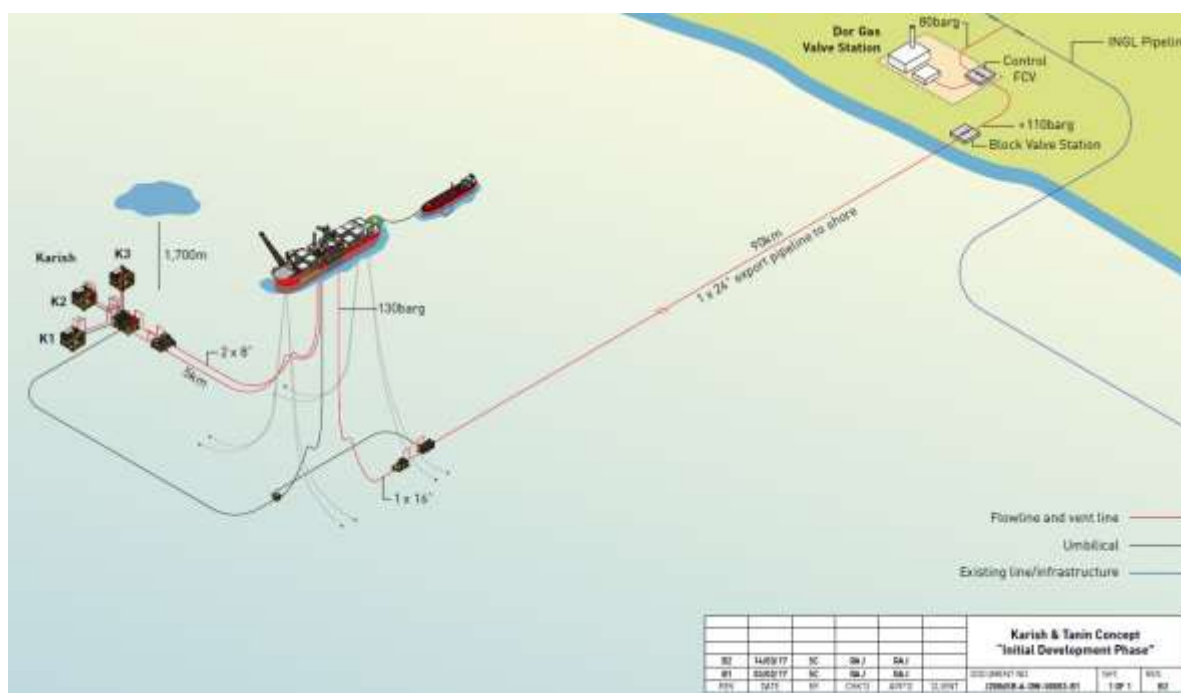


Figure 1-5 Initial Karish Development

The following figure illustrates how the initial infrastructure would be expanded to allow the Tanin A block to be developed. Prior to the development of Tanin it is envisaged that the Karish North exploration prospect (and potentially the Karish East exploration lead) would be drilled. Karish North would be tied back via the Karish sub-sea manifold (as shown). Karish North represents a more attractive development project than the existing Tanin discoveries and would replace it in the production sequence if an exploration success. A Karish North exploration well would be designed for development service and immediately linked in to the Karish Main manifold.



The following figure illustrates one particular build-out. Additional discoveries in the north of the Tanin Lease (Blocks E and F) could be tied back to the Tanin manifold. Access to the gathering network would be provided in Block 12 (which sits between the Karish and Tanin Leases). Discoveries to the East of Karish would be tied back directly to the FPSO through new risers. As the volume of near and further-field discoveries increases it is possible that volumes of gas can be dedicated for export. Hence two 12" riser slots will be included for gas export lines. These could either link into a gas export scheme driven by Leviathan or create a new (small scale) export route to (and then via) Cyprus.



1.1.3 Overview of Karish and Tanin development infrastructure

As outlined earlier and illustrated above, the proposed development scheme centres around the installation of an FPSO immediately south of the Karish Main field. A review of the available market for FPSO's did not identify a unit of an appropriate specification that will come off-lease before the planned start-up date. Hence a new FPSO will be developed. The hull of the FPSO will be a new-build, based upon an existing design. This design has previously been classified by DNV-GL. The FPSO hull was demonstrated as representing the critical path of the project and by adopting an existing design the schedule could be significantly reduced. FEED work for the hull has commenced. A new-build hull was seen as technically less risky than a tanker conversion.

The FPSO will be moored with its bow headed west, facing the majority of severe weather conditions. Production risers will be tied into the north of the vessel with the sheltered southern side being used by support vessels. The Gas export riser will be located at the stern-end of the southern side. With a new-build vessel, accommodation can be positioned at the bow and the flare at the stern. This is the safest arrangement considering prevailing weather conditions. A vertical flare is envisaged but alternatives may have to be considered in light of security requirements.

The FPSO will have storage capacity of 1,000,000 bbls and oil would be offloaded in parcels of about 350,000 bbls to smaller tankers for export to European Markets. With a projected initial liquid production rate of around 6,600 bbls oil/day (at a gas rate of 300 mmscf/day), tanker loading operations would occur once every 55 days (7 loadings per year). Should weather conditions delay a routine loading there would be no impact on gas production given the large volume of storage available. 800,000 bbls of storage capacity will be dedicated to dehydrated oil ready for loading. 100,000 bbls of storage will be used to provide the residence time needed to allow water and oil separation to occur. This arrangement will give an average residence time of 9 days (for oil) and more than 500 days for water. The remaining 100,000 bbls of storage will be used for produced water. This will allow water to be stored for a number of years prior to discharge. In this time all free oil will be removed by gravity and recycled to the production system. Water discharged to sea will therefore be as clean as technically feasible.

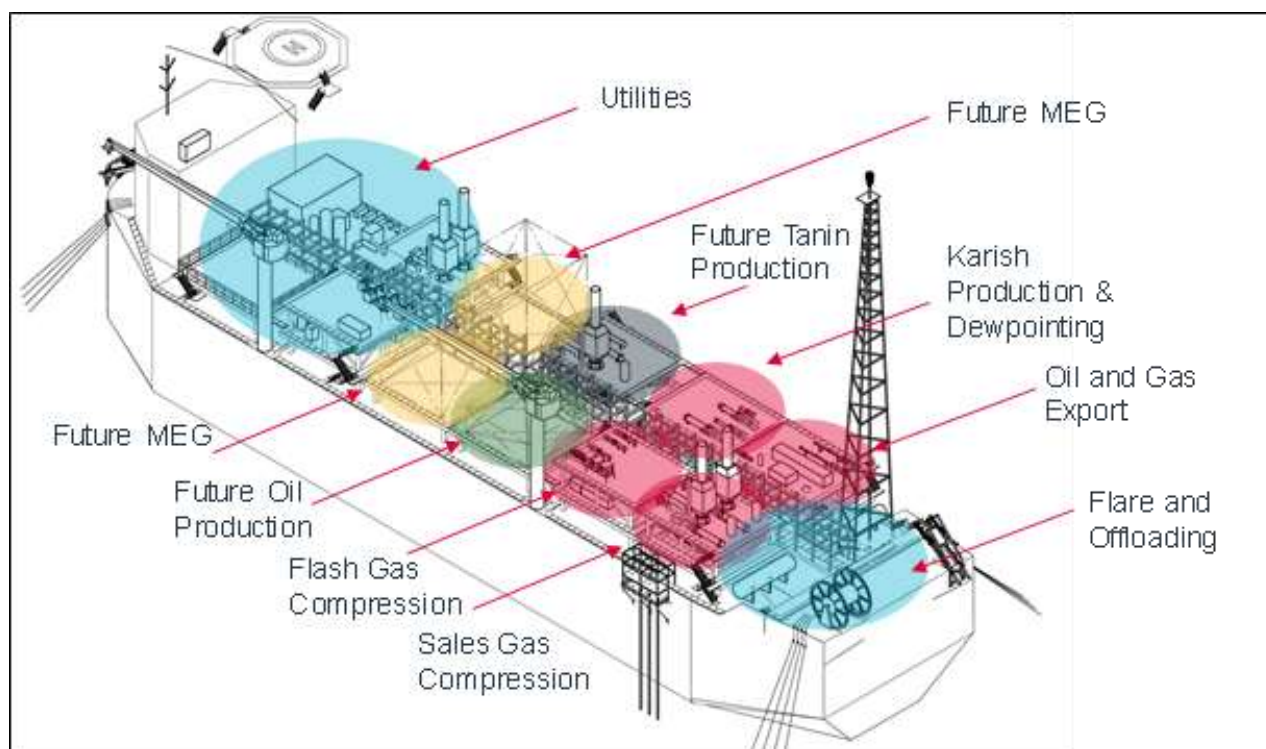


Figure 1-8 Overview of the Karish and Tanin FPSO

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Process facilities will be located on the FPSO deck in a sequence of single or double layered modules. Given the large hull-size proposed (260m by 50m), and the relatively simple processing requirements, a large amount of spare deck space will be available at initial production capacities. This deck space will be used to add processing capacity should market demand increase and additional volumes be identified in northern Israeli waters via exploration to allow this demand to be satisfied. Similarly, production from a deeper oil discovery could be accommodated via additional modules placed on the large deck. Currently it is calculated that some 8,000 tons of process equipment will be required to provide 400 mmscf/day of gas capacity as well as that for the treatment of associated, condensate and water. Around 60% of available deck space will be employed initially.

Gas and associated liquids (mixed light-oil and condensate) will be produced from 3 new-drilled wells. These wells will fully exploit the Karish Main reservoirs (except volumes that could be discovered in the A reservoirs). The wells will be tied back to a 4-slot manifold and from there via parallel risers to the FPSO. Pressure control will be undertaken at the entrance to the FPSO to minimize temperature drops in the sub-sea pipeline system. MEG will not be required to manage hydrate formation given the low residence time and hence temperature drop. Methanol will be used for shutdowns and at start-up. Flowlines and risers will be wet-insulated. Risers will be lazy-wave SCR.

The process facilities required on the FPSO are simple. A single, 100% capacity, train will be installed for gas/liquid separation and gas dehydration. Name plate capacity will be 400 mm scf/day making it possible to produce at an annual average rate of around 300 mmscf/day assuming daily variations between 400 and 200 mmscf/day. It is important that the line-pack in the dry-gas pipeline to shore is used to minimise the need to constantly modulate the flow from the reservoirs when sales rates vary during a typical day.

Processing will be undertaken in a single train comprising an inlet separator, two JT valves installed in series, a low temperature separator and associated gas-gas heat exchangers and inter-stage vessels. MEG will be injected to remove water down to the required dew point. After entering the FPSO the Karish dense-phase fluid will be choked from an initial pressure of above 400 bar to 200 bar. Liquid will be removed in the high pressure inlet separator and sent to the oil stabilization train. Wet gas at 200 bar will be passed to the JT-based dehydration system where its pressure will be reduced to 80 bar and a temperature of some -18°C. This would achieve a hydrocarbon dew point below the +5°C level required for transmission through the INGL system. The cold mixed phase fluid is then passed to a Low Temperature Separator where dry gas, wet-MEG and condensate/oil separated. The dry-gas stream will be passed to a single-stage export compressor that restores pressure to a maximum of 135 bar. Wet MEG would be passed to the MEG regeneration unit. Hydrocarbon liquids would be fed to the oil separation and stabilization system.

Two 100% export compressors will be installed. These will be electrically driven, variable speed, centrifugal units and hence should contribute to an overall system availability above 98%. Hydrocarbon liquids separated in the inlet/HP and Low-Temperature separators would be fed to a simple, low-capacity, multi-stage, oil separation train. Separated gas would be recompressed via a single, 3-stage flash gas compressor and fed either to the fuel gas system or the dry-gas exiting the Low Temperature separator at 80 bar. As the dehydration unit achieves a dew point significantly below the pipeline specification it will be possible to spike some of the rich flash gas back into the export stream without this stream going out of specification.

The FPSO will be equipped with a central power generation system comprising three 13 -16 MW gas turbine driven generators. In winter whilst not loading a tanker a single unit should be able to supply all electrical load. In summer and when oil is being loaded two machines will be run in parallel. Two of the power turbines will be equipped with waste heat recovery units. Heating will be via a closed loop system containing mineral heating oil.

Integrated reservoir, well and facility simulation work has demonstrated that the target gas sales rate of 290 mmscf/day (3 BCM/year) can be delivered initially by a single Karish Main well. Two wells would however be required to produce at the envisaged 400 mmscf/day peak rate. Hence three wells will be pre-drilled and available at day 1. This will ensure that a spare well is available. The degree of support from the aquifer underlying the Karish Main field will dictate how quickly the reservoir pressure will fall and hence how well-deliverability will change with time and ultimately what recovery factor will be achieved. Strong aquifer support

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will achieve recovery factors between 65 to 75%, with no need for additional compression as long as wells can be positioned to allow the reservoirs to be effectively swept and minimize early water production. Initial wells will be completed on the C Reservoir with an open-hole gravel pack. These will produce gas from the C and D reservoirs. They will also produce part of the B reservoir volumes (i.e. that gas down-dip of the top of the C unit OHGP in the B reservoir flanks). Offtake from the wells will be matched with connected gas volumes in an attempt to ensure that all wells will water-out at approximately the same time. Depending on the gas sales profile, actual reservoir size and aquifer strength this will be 14 to 19 years after start-up. At this point the wells will be worked over, the C sand completion isolated mechanically and a cased hole gravel-pack completion installed to allow the remaining volumes in the B sands to be recovered. The B sands will then be produced at a maximum rate of around 100 mln scf/day from 1 to 3 wells. A second B sand case has been assessed where it is assumed that no B gas is produced through the C sand OHGP. The B sand remains at virgin pressures and its entire volume is produced after the C/D zones have watered out. This accelerates the need for Tanin development by about 4 years.

In either case, gas from the Tanin field will not be developed for many years after initial project sanction. Tanin would be developed so that gas is ready 2 years before the point where the Karish C/D sands are depleted. As discussed in section 7 it is planned to measure the reservoir pressure in the B sands whilst draining the C/D to assess the contribution of these layers. If Karish North and/or Karish East are discovered before Tanin is developed, the development of Tanin would be further delayed. Tanin could be accelerated if the aquifer at Karish is weaker than envisaged, or the gas market develops more rapidly. Whenever Tanin is developed it would be tied back to the Karish FPSO in the same manner. A 4-6 slot manifold would be located at a central location in the Tanin field and connected to the Karish FPSO through dual multi-phase transfer lines. These would likely be of 10" diameter. Hydrates will be managed by electrical heating of the sub-sea infrastructure. 3 wells are likely needed to develop the discovered resources in the A block efficiently. These would be drilled in parallel with installing the multiphase infrastructure. Additional accumulations would be tied back through the spare slots. If all mapped structures contain gas then up to 8 wells may eventually be required. In the case where there is no early Karish B sand production there would be a second drilling campaign to drill Tanin C wells 6 years after Tanin comes into production (2040). A single well in Tanin B would be drilled 4 years later (2044). As noted, not all of these late-Lease wells are included in the FDP economics. Recovery factors in Tanin even with 6 wells are predicted to be lower than Karish Main. This is because the small volumes present in the B sands can not be developed effectively with a well completed on the A. These deeper volumes do not justify dedicated wells.

Production from Tanin would be routed through separate risers to allow production from the two fields to be controlled independently via dedicated chokes at the FPSO inlet. A second processing train may be added at the point Tanin is developed should its development mark an increase in sales. If not then Tanin would flow into the existing train likely through a separate inlet separator. It is probable that a second train identical to that described above would be installed if capacity is expanded. The need for a 3rd export compressor is not envisaged: electrically driven centrifugal compressors giving very high availabilities. Space has however been allowed should an additional export compressor be required to meet sales availability targets. This would give a name plate capacity of 800 mmscf/day although it is currently envisaged that annual average sales would not exceed 600 mmscf/day. A 24"/30" export pipeline operated at an inlet pressure of 135 bar would have a capacity of > 800 mmscf/day. Space has been allowed for a 4th power turbine if required. Hydrate management in the Tanin gathering system would be by insulation and the use of Direct Electrical Heating. Space has been allowed on the Karish FPSO for a MEG regeneration and reclamation system but currently it is not envisaged that this would be required. Very distant (as yet unidentified) tie-backs may require MEG for hydrate management.

At a later date it is envisaged that deeper (Cretaceous) structures could be drilled below Karish and Tanin in an effort to determine whether they contain additional volumes. Source rocks feeding these deeper reservoirs are expected to be oil prone. An oil discovery would trigger a separate development via the FPSO if deemed commercial. Clearly an oil development immediately below Karish would have more development synergy with the FPSO than one below Tanin.

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1.2 Project schedule and costs

1.2.1 Project schedule

Energean targets delivery of gas to Israel from the Karish field by early 2020. A “most likely” start-up date of April 2020 is envisaged with first oil sales approximately 2 months later. Energean is committed to introducing an alternative supply of gas to Israeli consumers as early as feasible to improve security of supply and competition. Schedule to first gas was ranked as one of the most important project Value Drivers and the scope of the development and the adopted contracting strategy have been designed so as to ensure early start-up.

As project definition further deepens during the next design phase the overall schedule will be updated and a probabilistic (risked) assessment developed. This will enable P10, P50, P90 and Pmean schedules to be produced and compared with the reference-case described in this FDP. Based upon the deterministic work undertaken to date the following key dates and milestones are defined. The critical path of the project is seen to pass through the design and construction of the FPSO hull. To minimize schedule and ensure start-up as early as feasible, FEED level engineering has commenced prior to FDP submittal. Detailed engineering will commence in parallel with FDP review and approval.

- Subsea Pre-FID Engineering Design contract award: early June 2017
- Selection of hull fabrication yard: July 2017
- Selection of topsides and integration yard: July 2017
- Geotechnical, geophysical and Environmental Base Line Survey: July 2017
- Approval of FDP by Israeli government: August 2017
- Selection of rig and drilling services contractors: August 2017
- Award of EPCmIC contract: October 2017
- Completion of full project EIA (ESIA): October 2017
- ITT's issued for identified Long Lead items: November 2017
- Project sanction: end 2017
- Award main project contracts: January 2018
- Commence hull fabrication: Q1 2018
- Commence topsides fabrication: Q2 2018
- Commence drilling operations: Q3 2018
- Commence FPSO hull topsides integration and commissioning: Q2 2019
- Complete drilling operations: Q2 2019
- Commence pipeline installation: Q2 2019
- Undertake SURF pipeline installation: Q3 2019
- Mobilise FPSO from Asia to Europe: Q4 2019
- Hook-up FPSO to SURF and pipeline: Q1 2020
- Final commissioning and start-up: Q1 2020
- First gas sales: April 2020
- First oil sales: June 2020

The project schedule is illustrated in the following figure.

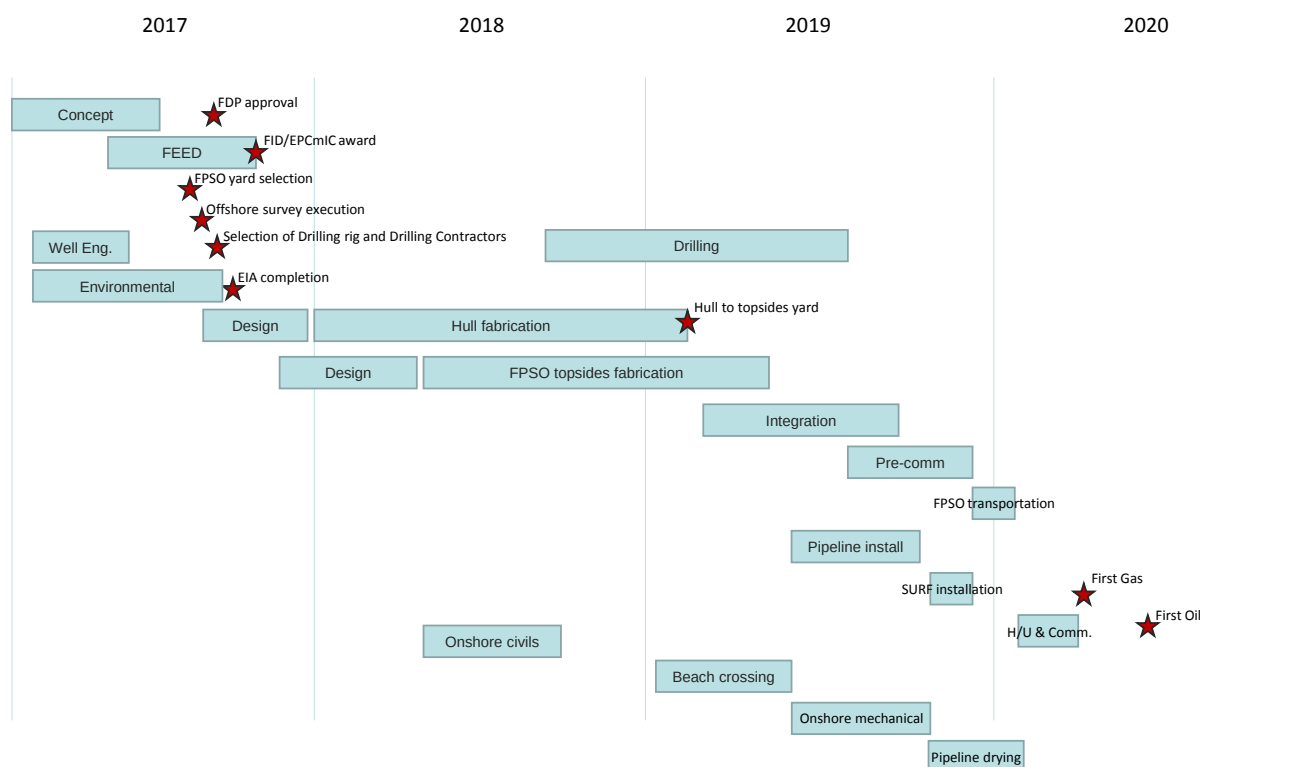


Figure 1-9 High level overview of the project schedule

1.2.2 Project capital costs

Project costs have been determined for the initial development of the Karish Main field and the subsequent satellite developments of Tanin A, B and C Blocks and Karish North. The cost estimate for the Karish elements is considered more mature than that of Tanin. Considering the phased nature of the project and the uncertainty in the exact year Tanin will be developed this is to be expected.

The total capital cost of the Karish development (to first gas) is estimated to be US\$ 1,191 mln. Annual operating costs post start-up are expected to be in the range US\$ 50 to US\$ 60 mln. These figures assume that the FPSO will be purchased and owned by Energean Israel. It is possible that the FPSO will instead be leased, in which case the above CAPEX would be reduced and the annual OPEX increased.

The incremental cost of developing the Tanin discovered resources is estimated to be US\$ 600 mln including the 3 new-drilled A-block wells. Annual OPEX following Tanin start-up will rise by approximately \$10 mln/year

Project costs are described in detail in section 8.3 below. The following main project building blocks are considered for the initial development:

Table 1-2: Overview of project CAPEX

MAIN COST ITEMS	SUB COST ITEM	END CONCEPT PHASE ESTIMATE
		(US\$ mln)
Karish Main Wells	Rig hire	55.7
	Services	55.4
	Tangibles	47.9

Karish SURF	Project Management and Engineering	17.3
	Procurement and Fabrication	104.4
	Installation	85.1
FPSO hull	Hull fabrication	142.5
	Quayside integration and lifting	5.0
	Delivery hull yard to topsides yard	1.5
	Delivery China to Israel	21.8
	Contractor indirect costs	7.1
	Contingency (15%)	27.7
Mooring Systems	Procurement and fabrication	50.8
	Contingency (15%)	7.6
FPSO topsides	Procurement	115.1
	Yard deck fabrication	64.2
	Yard Pre-commissioning	12.8
	Site hook-up and commissioning	9.1
	Contractor costs	57.8
	Insurance and certification	5.0
	Contingency (15%)	39.6
Dry gas pipeline	Project Management and Engineering	16.9
	Procurement and Fabrication	73.6
	Installation	76.5
Onshore/Beach	Beach crossing (HDD)	42.4
	Onshore pipeline	3.5
	Onshore facilities	
Others	Owners costs post FID	45.0
Total		1,191.3

The following summarizes subsequent costs for the development of the Tanin A, C and B blocks, Karish North (single well development) and work-over of the Karish wells to produce from the B reservoir sands. There is no firm plan as yet to drill or develop Karish North. Costs are included for completeness. Although the FPSO has been designed so that it can be extended to deliver gas at a rate in excess of 6 BCM/year, no costs for this extension have been included as the Reference Case assumes a constant gas sales rate of 3 BCM/year. Ramp up would require the additional topside processing train described in section 7 and potentially an additional dry gas riser (for peak rates above 650 mln scf/day). These costs would be less than \$100 mln. Additional wells would also have to be drilled to support offtakes above 4 BCM/year.

Table 1-3: Tanin and Karish North project CAPEX

ADDITIONAL COST ITEMS	PROBABLE YEAR OF EXECUTION	END CONCEPT PHASE ESTIMATE
		(US\$ mln)
Tanin SURF	2034-2036	280.2
Tanin DEH system	2036	140.0
Tanin A Well x 3	2036	180.0
Workover Karish C to B zones	2040	54.0
Tanin C well x 2	2042	140.0
Tanin B well x 1	2045	80.0
Karish North SURF	Unknown	43.5
Karish North well x 1	Unknown	60.0
Total		977.7

1.3 Estimate of In-place Resources, Recoverable volumes based upon the proposed development and associated Gas production profiles

1.3.1 In-place volumes

The following tables summarise the calculated, mid-case, initially in place gas volumes (GIIP) in the Karish and Tanin Leases. Volumes for the discovered accumulations (Karish Main, Tanin A, B, C) and the remaining exploration prospects and leads in the Lower Miocene (unrisked), are provided. Additional deeper upside potential is outlined in the detailed report though volumes have not yet been fully quantified.

Table 1-4: Gas Initially In Place - Discovered Accumulations

DISCOVERED FIELD	RESERVOIR UNIT	GIIP	
		BCM	BSCF
Karish Main	A Sand	7.2	255
	B Sand	23.7	837
	Upper C Sand	40.3	1,424
	Lower C Sand	17.4	616
	D Sand	10.2	362
	Total	98.9	3,494
Tanin A	A Sand	22.3	787
	B Sand	5.3	186
	Total	27.5	973
Tanin B	A Sand	3.5	124
	B Sand	0.9	31
	Total	4.4	155
Tanin C	A Sand	13.3	469
	Total	13.3	469
Total GIIP in discovered accumulations		144.1	5,091

Table 1-5: Gas Initially in Place - Yet-To-Drill accumulations

UNDISCOVERED FIELDS	RESERVOIR UNIT	GIIP	
		BCM	BSCF
Karish North	B Sand	18.5	654
	Upper C Sand	20.8	734
	Lower C Sand	10.0	353
	D Sand	6.2	220
	Total	55.5	1,961
Karish East	Upper C Sand	13.2	467
	Lower C Sand	6.7	238
	D Sand	4.2	150
	Total	24.2	855
Tanin D	A Sand	1.6	57
	B Sand	0.3	9
	Total	1.9	66
Tanin E	A Sand	10.0	353
	B Sand	4.1	145
	Total	14.1	499
Tanin F	A Sand	9.6	338
	B Sand	1.8	65
	Total	11.4	403
Total GIIP in undiscovered accumulations		107.1	3,784

1.3.2 Recovery factors

Based upon the Reservoir Engineering dynamic simulation model built in Eclipse and assuming an aquifer strength in line with that measured at the nearby Tamar field, the following “best technical case” Recovery factors have been calculated (see Section 6). This work shows that due to the expected strong aquifer, high quality sands and low heterogeneity (based upon the analogue Tamar field), little remaining gas remains to be produced after water break through occurs in a particular well. In general, simulation work has indicated that 95% of the recoverable volume is produced before water break through and only 5% after.

Table 1-6: Expected “best technical case” Recovery Factors

FIELD	RESERVOIR UNIT	RF
Karish	C/D combined	68%
	B	65%(1)
Tanin	A/B combined	62% (2)

Table Notes: (1) Recovery factor for the Karish B reservoir of 53% is predicted via the initial C/D sand OHGP due to fault communications. Following recompletion the Rf. increases to 65%. This includes C gas produced through the B unit. In the alternative case where it is assumed no gas production via the C/D the overall Rf. post recompletion is 65%. (2) This is total recovery from the A/B sands. Recovery from the B sands is around 34%.

Clearly water may break through earlier than predicted due to increased heterogeneities (above that seen in the Karish-1 log or the Tamar field). Production post water breakthrough would therefore be more significant. To account for this the facilities have been developed to allow higher water-gas-ratios to be handled. This is discussed in Section 7.

Although it is expected that the Karish and Tanin fields will enjoy strong aquifer support and hence little pressure drop during production, an FPSO has been selected (partially) to ensure good recoveries can be achieved even if the aquifer is weaker. By providing a facility that can operate at low inlet pressures, reservoir pressures can be depleted significantly and indeed in these cases higher Recovery Factors can actually be achieved. Recovery Factors under pressure depletion are no longer limited by residual gas saturations to the influx of aquifer water.

1.3.3 Integrated Production System capacity to be developed

The potential of the three planned wells to be drilled initially in the Karish Main field and completed to develop the C/D reservoirs as well as the capacity of the installed Integrated Production System, will likely exceed the size of the available gas market in Israel when the Karish field first comes into production. Each of the Karish wells will have an initial capacity when producing against the minimum HP separator back pressure in excess of 300 mmscf/day. Hence the installed well capacity on day-1 will be close to 1,000 mmscf/day.

The FPSO when fully developed will have a capacity of 800 mmscf/day. Initially only 1 of the 2 parallel gas processing trains will be installed, hence throughput will be limited to around 400 mmscf/day. Gas export compression capacity will be 800 mln scf/day as both units will be installed on day 1. The eventual gas export pipeline capacity to shore will be 800 mln scf/day. On day-1 it will be limited to around 650 mmscf/day as only 1 of the 2 envisaged risers will be installed.

For the current FDP it is assumed that Energean will agree gas sales contracts for an annual average production rate of 3 BCM/year. 3 BCM/year sales will require a daily fluid production from the reservoir of 305 mln scf assuming 98% availability, 1% fuel gas use and 1.5% shrinkage associated with liquid removal (to give an average production of 290 mmscf/day, or 3 BCM/year). This level is well within the overall design capacity of the Integrated Production System which is driven on day 1 by the capacity of the FPSO gas processing train (400 mln scf/day).

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1.3.4 Reference Case Production profiles – “early contribution of Karish B-sands”

Based upon the above sales assumptions, the calculated GIIP volumes and the predicted recovery factors for the phased development of each discovered field (Karish Main, Tanin A, Tanin C, Tanin B) a Reference Case production forecast and associated drilling/development schedule has been prepared and used to assess the economic attractiveness of the proposed development. In this Reference-case, early production from the Karish B-sands as predicted by the Eclipse simulation model is included, i.e. part of the B sand gas is co-produced via the Karish Main wells completed on the C sands. Karish Main D reservoirs are also drained in this manner

Karish B/C/D reservoirs of Karish Main: Will be developed between 2017 and end 2019 with first gas end Q1 2020. 3 wells will be drilled in 2018/2019. Costs as presented above. The Karish C/D reservoirs contain 2,400 Bcf GIIP. Discounting for fuel gas and liquids shrinkage and with a recovery factor of 68% this volume will provide 1,591 Bcf of sales gas (45.1 BCM). 95% (or 42.8 BCM) is produced during the plateau period. The remaining 5% (2.3 BCM) is produced in a two year period after the plateau period ceases. The Karish B sands contain 837 Bcf GIIP. Again discounting for fuel gas and shrinkage and with a recovery factor of 53% they will provide 432 Bcf of sales gas (12.2 BCM). 95% or 11.6 BCM is produced before the Karish C sands cut water and the remaining 0.6 BCM in the 2 years after. At a rate of 3 BCM/year a plateau period for Karish Main of 18.1 years is calculated. Hence the Karish initial plateau is predicted to finish Q2 2038.

Karish B reservoirs of Karish Main – remaining production: The remaining potential of the Karish Main B sands (and a small volume of additional C sand gas) will be developed after the 3 Karish C/D wells water out. Based upon the above, the planned workovers would be executed mid-2040. Remaining recoverable volumes at this point in the Karish Main B reservoir would be 101 Bcf GIIP, or 98 Bcf (2.8 BCM) of sales gas. At an annual production rate of 1 BCM/year, this equates to approximately 3 years of additional production.

Tanin A/B reservoirs of the Tanin Blocks A, B and C: Will be developed so that gas can be produced 2 years prior to the point where Karish C/D reservoir wells are forecast to water out (come off their initial plateau rate). Hence the development project will be executed over the years 2034-36. Tanin A, B and C blocks contain 1,597 Bcf GIIP, or 965 Bcf (27.3 BCM) sales gas. Production would commence at an initial low rate, build to a rate of 2 BCM/year for 4 years and then increase to 3 BCM/year until end 2047. Production would end in 2050, i.e. beyond the end of the initial Lease period. Minor production (0.7 BCM/year) would be produced in the period 2049 to 2050. Tanin C would be developed in 2042 and Tanin B in 2045.

Possible volumes in the Karish Main A-sand reservoirs are not included. Based on these above assumptions, the following production profiles are generated:

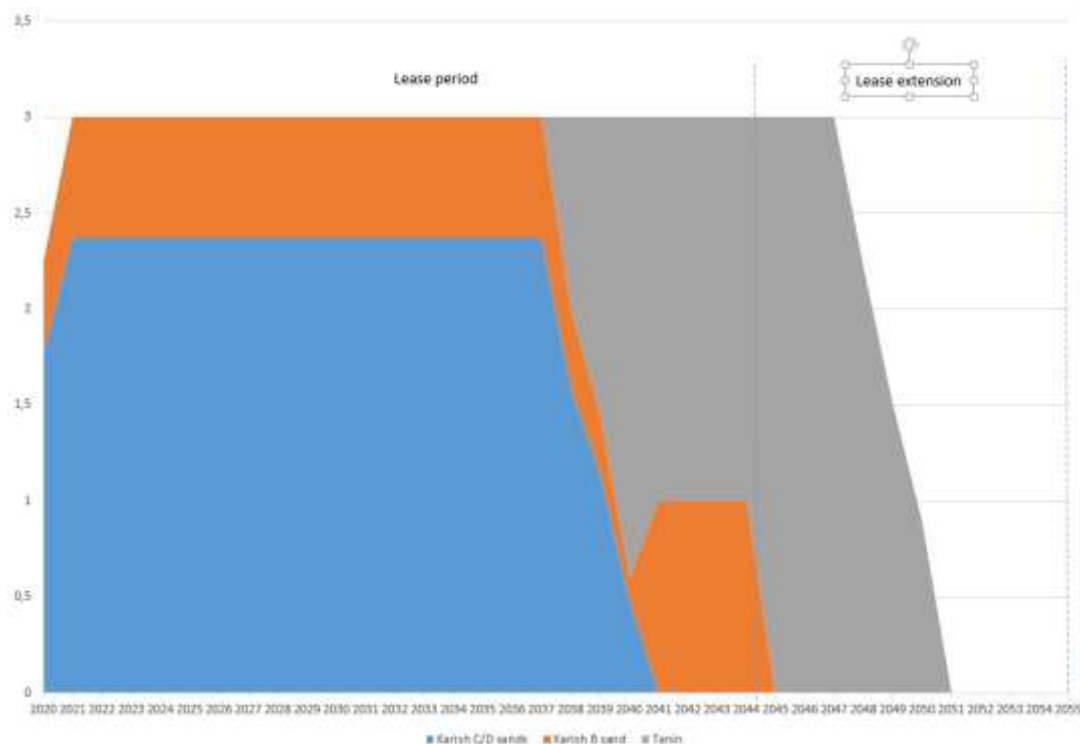


Figure 1-10 Reference-case gas production forecast for discovered Karish and Tanin accumulations

Associated with the Reference-case profile some 44.1 mln bbls of light oil will be produced. Of this 35 mln bbls are produced from the Karish C and D reservoirs, 3.3 mln from the Karish B reservoirs and 5.0 mln from the Tanin reservoirs. A liquids production profile (mln bbls/year) is provided below. This shows a lower initial liquids rate than the Alternative-case discussed below as gas production from the C/D is deferred. This is conservative. In reality the liquids rate would actually decline from a common starting point as B reservoir gas finds its way to the C reservoir perforations. A more detailed liquids forecast will be generated in the next development phase. This current Reference case is therefore somewhat conservative with regards liquid revenue.

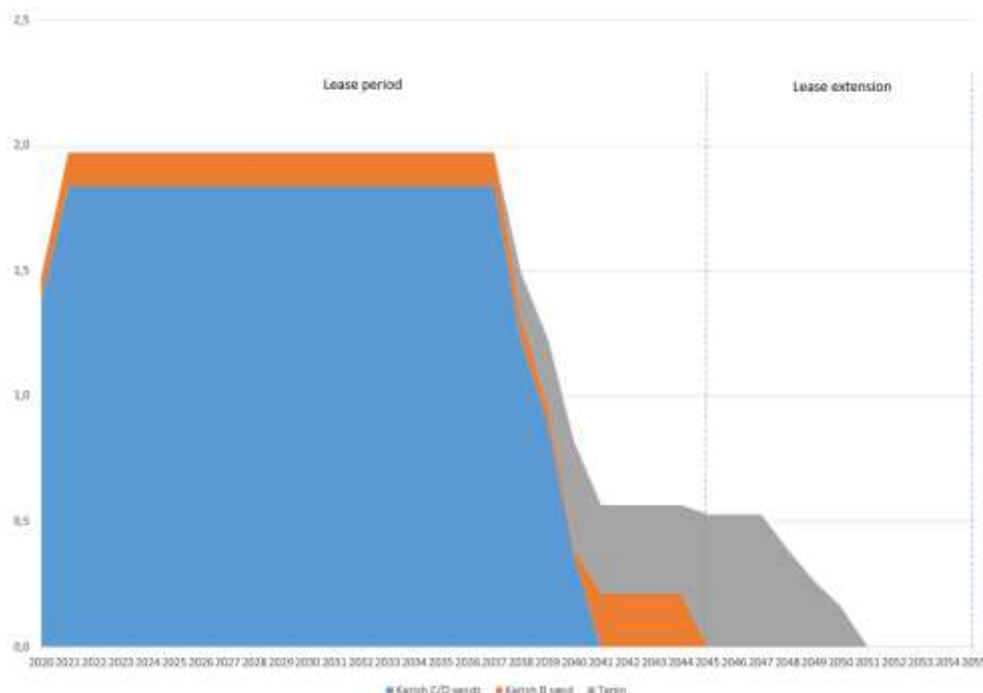


Figure 1-11 Reference-case liquids production forecast for Karish and Tanin discovered accumulations

1.3.5 Alternative Production profiles – no early Karish B-sand production

In the Alternative production-case it is assumed that there is no gas production from the Karish B-sands via the Karish C/D OHGP. This case requires the earlier development of Tanin and was seen to be a sufficiently interesting end-member sensitivity on the defined Reference-case to be included in this FDP. Clearly there are many other sensitivities – largely involving the discovery of further gas volumes close to Karish Main and the FPSO – that would also have a significant impact on the timing of the Tanin field development. These sensitivities are not included in the FDP as they involve exploration activities that are not yet planned (as well as exploration risk). All such scenarios will be developed in the next development phase, using logic-tree analysis, with the objective of developing a full probabilistic analysis of the total value of the Karish and Tanin Leases. This work will include an assessment of the potential for gas sales growth above 3 BCM/year.

The following underpins this alternative scenario:

Karish C/D reservoirs of Karish Main: Will be developed between 2017 and end 2019 with first gas end Q1 2020. 3 wells will be drilled in 2018/2019. Costs as presented above. The Karish C/D reservoirs contain 2,400 Bcf GIIP. Discounting for fuel gas and liquids shrinkage and with a recovery factor of 68% this volume will provide 1,591 Bcf of sales gas (45.1 BCM). 95% (or 42.8 BCM) is produced during a plateau period of 14.3 years at an annual average rate of 3 BCM/year. The remaining 5% (2.3 BCM) is produced in a two year period after the plateau period ceases. The Karish initial plateau is predicted to finish mid-2034.

Karish B reservoirs of Karish Main: It is assumed no production occurs from the B sands via communication with the C reservoir. The B sands will therefore be developed after the 3 Karish C/D wells water out (work over and recompletion). Based upon the above, this work would be executed late 2036. The Karish B reservoir contains 837 Bcf GIIP, or 571 Bcf (15.0 BCM) sales gas at 65% Rf. At an annual production rate of 1 BCM/year, this equates to 14 years plateau period and the 2 additional years at 0.5 BCM.

Tanin A/B reservoirs of Tanin Blocks A, B and C: Will be developed so that gas can be produced 2 years prior to the point where the Karish Main C/D reservoir wells are forecast to water out (come off their initial plateau). Hence this incremental development project will be executed over the years 2030-32. Tanin A, B and

C blocks contain 1,597 Bcf GIIP, or 835 Bcf (26.5 BCM) sales gas. At an annual average extraction rate of 2 BCM/year a plateau period of 12.6 years is predicted. Production would start mid-2034 and run through to end 2047, i.e. beyond the end of the initial Lease period. Minor production (0.7 BCM/year) would be produced in the period 2047 to 2048. Tanin C would be developed in 2040 and Tanin B in 2044.

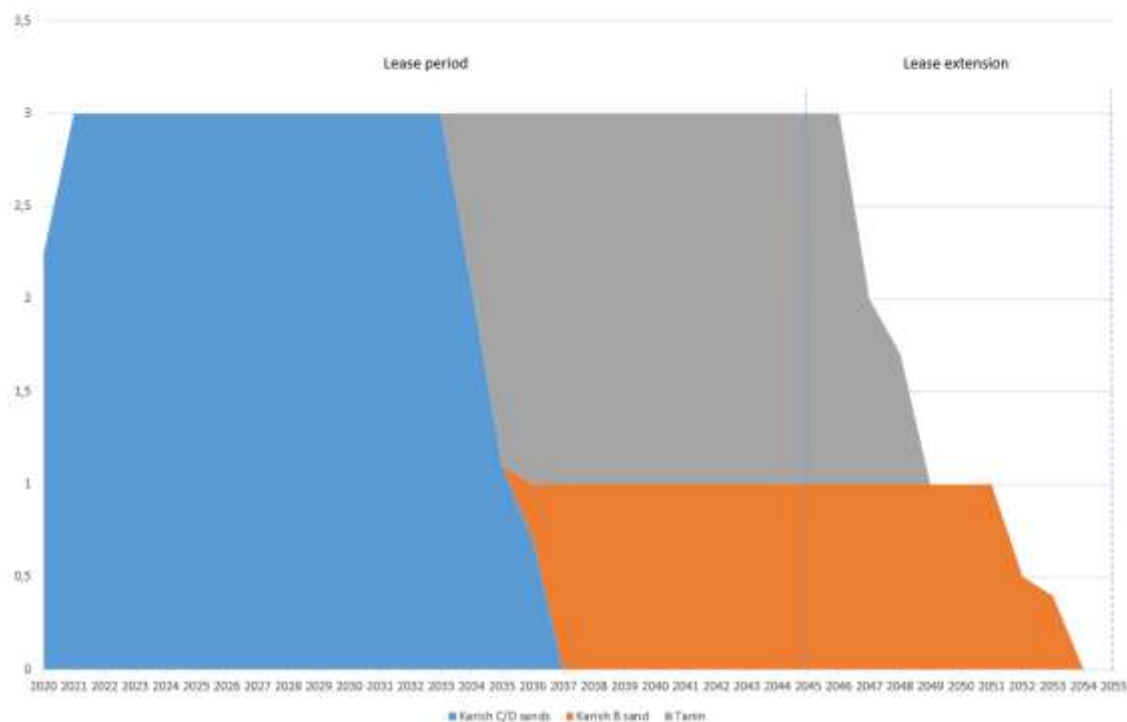


Figure 1-12 Alternative-case gas production profile for Karish and Tanin discovered accumulations

Liquid volumes produced from the Alternative Case are the same as the Reference Case, i.e. 44.1 mln bbls. A liquids production profile (mln bbls/year) is provided below. This case results in an acceleration of liquid production as C/D fluids are produced before the leaner B fluids.

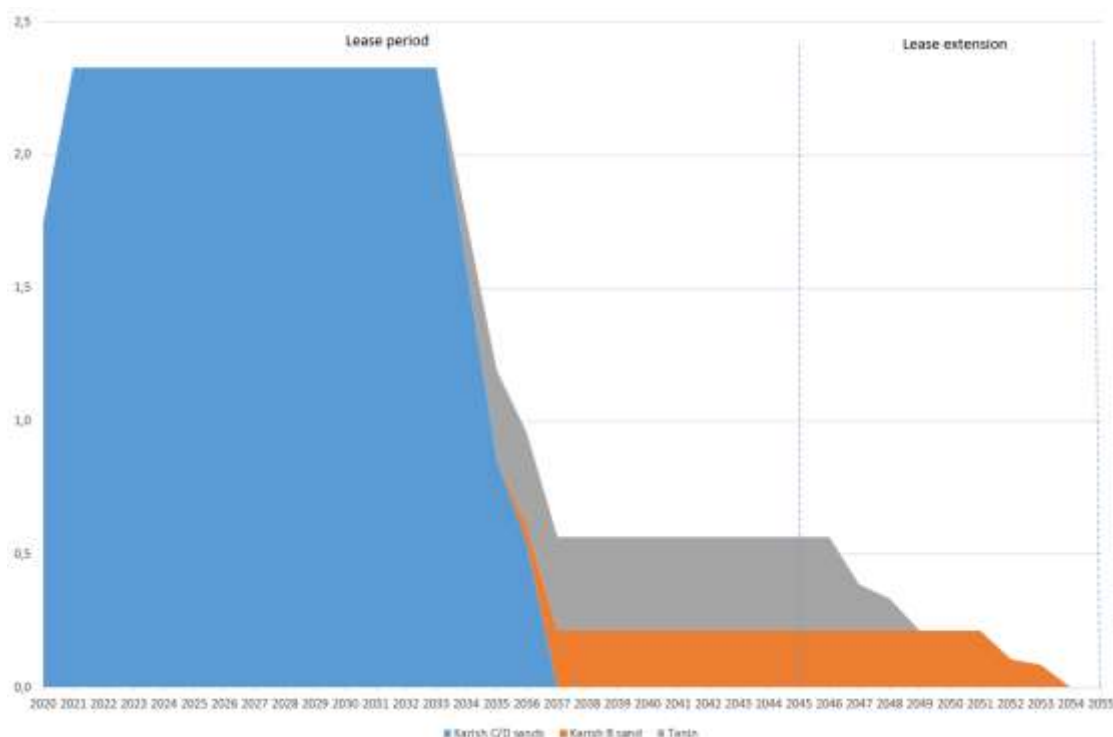


Figure 1-13 Alternative-case liquids profile for Karish and Tanin discovered accumulations

1.3.6 Other Production forecast considerations

Should the aquifer strength at Karish prove to be weaker than at Tamar the inlet separator pressure would be gradually dropped to 130 bar whilst maintaining the gas export pressure and specification. Should further reservoir pressure reductions be required to achieve, or exceed, the recovery factor achievable with a strong aquifer, inlet compression would be installed. Space is available for an inlet compression module. Simulation work has shown that with a weak aquifer it is possible to obtain substantially higher recovery factors than under a strong aquifer as long as inlet pressures can be reduced. With strong water influx ultimate recovery is limited by the residual saturation of gas under water flood. In the weak aquifer case the Tanin development would be phased back in time. CAPEX increases due to installation of inlet compression on the FPSO is offset by a reduction in spend at Tanin. With higher recovery factors the 10-year Lease extension would be exercised to maximise value from the existing discovered resources.

Should the Karish development result in lower than the “Best technical case” GIIP’s being confirmed the development of Tanin would be accelerated to maintain the production rate at the target level of 3 BCM for as long as necessary to satisfy sales contracts. The downside risk associated with the Karish Main C volumes is considered very low. As can be seen in the above figure, the Reference-case forecast extends outside the current firm Lease period and well after the envisaged 15-year tenure of the gas sales contracts. The undrilled exploration prospects and leads in the Leases, particularly Karish North and Tanin Blocks E and F would allow this plateau to be further extended or a higher plateau to be realized (clearly this would be Energean’s preference as it maximises the value of the Karish and Tanin Leases). Such upside scenarios are allowed for in the facilities created during the proposed development but are not explicitly described in this FDP.

1.4 Future developments

As discussed above the Karish and Tanin Leases contain a significant number of undrilled prospects and leads in the lower Miocene and deeper horizons. These are further described in the main part of this FDP although are not included currently in the planned development.

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The leads and prospects in the lower Miocene are very low risk (POS: 60-90%) as they are generally supported by direct hydrocarbon indicators (DHI's) and are part of the same play that has been successfully leveraged to date in the Levantine Basin. These upside volumes could be rapidly drilled and matured should either the existing discoveries underperform or should the Israel domestic gas market grow, justifying an increased production plateau rate. They therefore represent significant value potential both with regard to risk reduction and upside value generation. Hence as described above, the overall field development plan has made allowance for their eventual discovery and tie-back. The timing of exploration in the Karish and Tanin Leases will be reviewed regularly to ensure that risks and upside can be addressed expeditiously.

The most significant individual undiscovered accumulation in the two Leases is the Karish North prospect in the Karish Lease. This 3-way structure is located on the northern, down-thrown side of the fault that constrains the Karish Main structure. It is probable that this prospect contains resources in excess of those in the Tanin A, B and C discoveries. Its proximity to the Karish FPSO makes it a significantly more attractive second development than Tanin even given the fact it is associated with some exploration risk. Hence Karish North will be drilled at least 2 years prior to the planned development date of Tanin. In a success case this would allow Karish North to replace Tanin in the development-funnel. A Karish North discovery well could be quickly tied back to the Karish manifold. Risked exploration costs for Karish North are therefore minimal.

Current mapping suggests that Karish North and the Karish East lead may actually form a single accumulation of a similar size to that of the Karish Main discovery. The mapped spill point of the Karish East lead is on its south-east flank and is at the same depth as the DHI-supported GWC in the Karish North prospect lending credence to the argument they are in communication. Seismic in the Karish Lease will be re-processed over Q2/3 2017 with the objective of better imaging the eastern area of the Lease and hence to mature Karish East from lead to prospect status. Subsequent drilling of a combined Karish North/East prospect may be undertaken immediately after the development of the Karish Main discovery. Liquid yield from Karish North/East gas is currently unknown. Liquid charge originates either from the deeper (Jurassic) horizons or from the mini-basin mapped to the north of the Karish mega-complex. As Karish North/East are deeper and on the north side of the main Karish sealing faults, it is possible that the liquid yields from these upside prospects may be higher. The FPSO liquid handling system has been designed to cope with increased volumes of hydrocarbon liquids if required.

Results obtained during the development of the Karish Main field will be used to update Energean's understanding of the volume of gas in the B reservoir and hence optimise their development. Although currently it is planned to develop the B sands via the C sands and via work-overs after the C/D sands have watered out, it is possible that they may justify standalone wells that would enable volumes to be further accelerated into production (if needed). B sand acceleration delays liquids production and hence where gas sales volumes are constrained by market capacity, acceleration of B sand production is not desirable. This can be observed in the economic results presented above.

Similarly, when the Karish North or East prospects are drilled, data gathered will be used to assess the potential for finding prognosed (or higher) volumes within the Main field's A-sands. Karish North does not appear to have suffered the erosional events seen at the main field. It is therefore expected that any A-sands discovered at the Karish North structure should be similar to those over the flanks of the Karish Main structure effectively de-risking this upside play. Karish North volumes currently don't include potential in the A horizon as there appears to be no closure at this level.

1.5 Field Management

Reservoir management will focus on the monitoring of pressures to determine connected volumes and aquifer strength. Production forecasts per reservoir compartment will be prepared and offtakes per well managed to ensure each area is depleted at a similar rate. Forecasts will be used to refine the date the Tanin field (or any other discoveries) need to be developed. Individual wells will be equipped with wet gas meters that allow CGR and water-cut to be measured continuously. Wells will be equipped with down-hole pressure gauges to allow shut-in pressures to be determined at regular intervals. This will enable the strength of the aquifer to be

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confirmed as early as possible (although it took more than 3-years in Tamar to get initial confirmation of aquifer influx). The simulation models will be regularly updated to match historical data.

It is anticipated that the pressure in the B sands will be monitored whilst the combined C and D sands are produced. This data will be used to determine whether the B sands are indeed partly depleted through fault juxtapositions with the C sand as is predicted by the Eclipse model and included in the defined Reference-case. The volumes in the B sand will be firmed up during the drilling of the initial three Karish Main wells. B sand pressure when water breaks through to the C sand open-hole completions will be used to plan the subsequent B sand development (justify the work-over activities and fine tune internal gravel pack design).

The potential for using 4D seismic to track the progress of aquifer water as it moves through the reservoirs will be determined. Based upon the existing inversion work it is expected that it should be possible to determine water progress and predict breakthrough time, water cut build-up and identify areas of unswept gas. This information would allow the timing of follow up developments – Tanin etc. – to be optimized, enable water handling upgrades to be identified if needed and to look at the economic attractiveness of adding further development wells to maximise recovery factors. Funds for 4D seismic have not been included as yet in the current project budget but would not be significant considering the compact nature of the accumulations.

1.6 Safety and Environmental management

Energean Israel endeavours to maintain and improve safety performance and protect the environment through all of its operations. Its development in Israel will be conducted under the requirements of the European Offshore Safety Directive and in line with best practices regards management of the environment. A Report of Major Hazards (Safety Case) will be developed in parallel with the project and implemented subsequently. This document will underpin the safe operation of the facilities and the demonstration of ALARP and the continuous minimization of risk levels to the facilities and the individuals who work there. An environmental scoping report has been prepared and is included with this FDP. This document has been prepared in line with International Best Practice and has identified the elements to be addressed formally in the project EIA and ESIA. The final EIA and ESIA will be available Q3 2017 when base line data collection has been completed. Using the EIA as its basis, Energean will develop an Environmental Monitoring and Management Plan to ensure it minimizes its impact on the east Mediterranean eco systems and the surrounding shorelines. The proposed development scheme was selected partially because initial environmental studies showed it to have the smallest environmental foot print of all development options available. This primarily stems from the avoidance of bringing hydrocarbon liquids to shore, the simplicity of the process scheme and the very long water residence time possible due to large volume of storage.

1.7 Decommissioning

Considering the large volume of discovered and undiscovered hydrocarbons in the Karish and Tanin Leases and also the potential for the identification of other prospects in the adjacent exploration license blocks, coupled with the relatively modest consumption levels in Israel, it is probable that the Karish FPSO and infrastructure will still be in use at the end of the current Lease (August 2044). The Leases allow for 10 year extensions and all shared facilities will be designed with a 35 year life expectancy to ensure that they can be employed without interruption until the end of the extension. Individual field facilities will be designed for 25 year life.

The Lease requires a decommissioning plan and fund to be established once the remaining resources in the Leases drops below 8 BCM in total. It is highly probable that such a fund will not have to be developed in the main Lease period.

Although decommissioning is unlikely to occur before the Lease expires, work has been undertaken to determine the best approach to be followed. Given the use of an FPSO the impact and cost of decommissioning will be minimized. The FPSO will be removed in a reverse of the installation process and either taken to a location for scrapping or be re-used on a subsequent project. Wells will be abandoned to best international

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practices in force at the time. SURF and the pipelines will be hydrocarbon-freed and washed to reduce residual hydrocarbon levels such that they can be left in place. Decommissioning costs are discussed in Section 8.

1.8 Structure of this FDP

This Karish and Tanin FDP is structured into two parts. Sections 2 to 10 (inclusive) describe in detail Energean's assessment of the gas and liquid resources that can be produced from the Karish and Tanin Leases, the facilities and wells needed for their development, a schedule for developing these facilities and associated costs and the economics of a described "best technical" case for the overall project. Sections 11 to 15 provide preliminary details of how Energean intends to manage the execution of the project. This is material that will be further developed as the project moves forward. The information related to later stages, for example Production, is therefore less mature than that related to the next planned phase of activities. These sections although not strictly required in an FDP should provide a clear indication to interested parties of the maturity level of the project as it approaches FID towards the end of 2017.

2 Subsurface Geological and Geophysical evaluation

2.1 Regional Geological Setting

The Levantine Basin is situated in the eastern part of the Mediterranean Sea, offshore Israel, Cyprus, Lebanon and Syria in water depths up to 2,000m. The basin contains up to 10,000 metres of Mesozoic and Cenozoic rocks above a rifted Triassic-Lower Jurassic terrain (Roberts & Peace, 2007).

The northern boundary of the Levantine Basin is defined by Cyprus and the Larnaca Thrust Zone, and its north-western margin by the Eratosthenes Seamount. The Nile Delta Cone and the East Mediterranean coast define its southwestern and eastern margins (Figure 2-1; Breman, 2006).

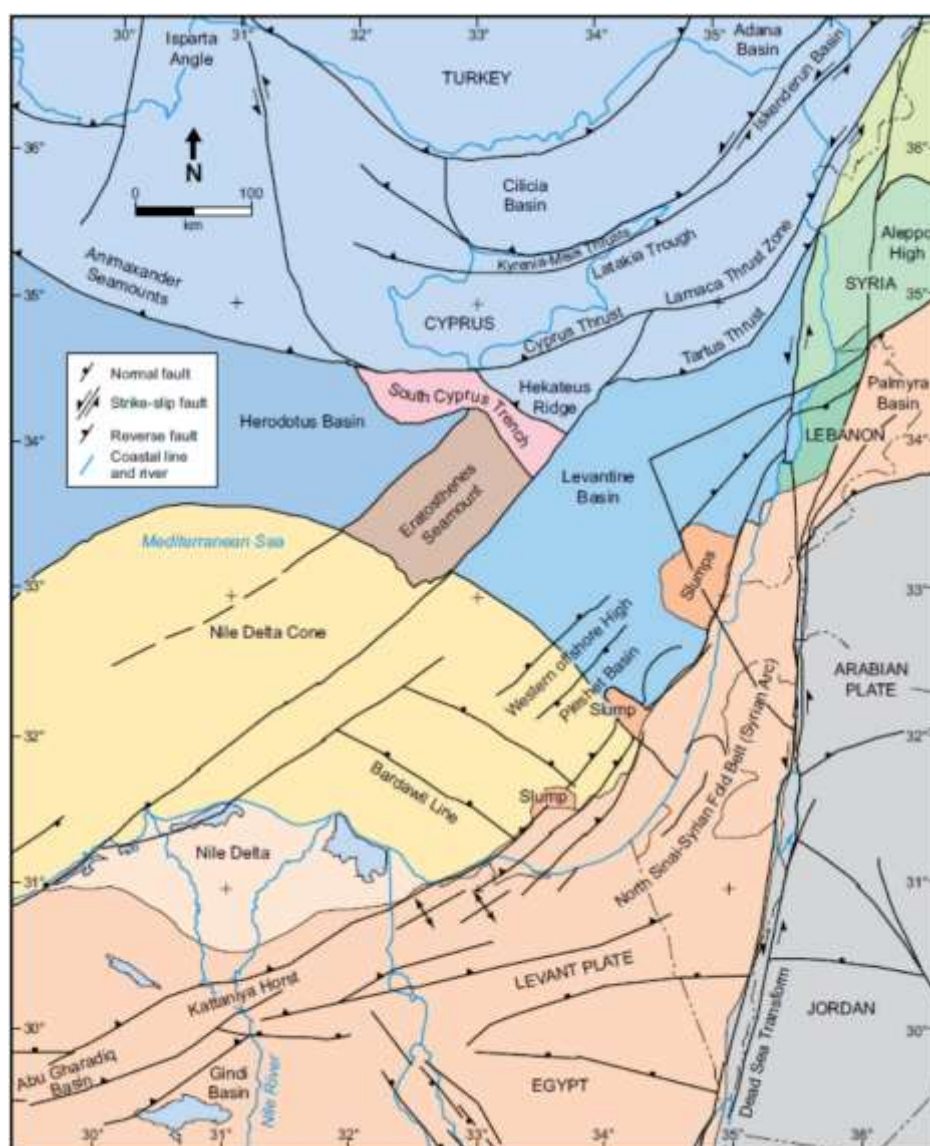


Figure 2-1 Tectonic elements in the East Mediterranean Basin (Breman, 2006)

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The basin is structurally complex with evidence of both compression and extension due to plate motions, salt tectonics and other gravitational processes. The basin is underlain by stretched continental crust. Reported geophysical estimates of the depth to the Moho are approximately 20 km versus 35–40 km for the true continental crust to the east.

Along the eastern Lebanon offshore margin and extending down into the north-eastern part of the Israel Offshore, there is good evidence of a North East-South West trending fault that runs semi-parallel to the Dead Sea Transform. This is evident in the vicinity of the Karish Complex. The Dead Sea transform fault accommodates the sinistral movement between the Levantine and Arabian plate's further inland (Aksu et al., 2005).

2.1.1 Levantine Basin Evolution

The Levantine Basin has undergone three major tectonic events (Gardosh, 2008): An Early Mesozoic rifting phase, Late Jurassic-Cretaceous subsidence and Late Cretaceous-Tertiary convergence.

2.1.1.1 Rifting

The East Mediterranean Basin formed during the tectonic break-up of the Pangea Supercontinent during the Early Mesozoic (mid-Permian to Middle Jurassic) rifting phase, resulting in the formation of an extensive setting dominated by horst and grabens, with the bounding normal faults reaching several kilometres in throw.

Mid-Mesozoic (Late Jurassic – Middle Cretaceous) post rift subsidence resulted in the formation of a deep marine basin bordered by a shallow marine shelf in what is the present day offshore. Following the mid-Permian to Early Jurassic break-up of the Pangea Supercontinent, the lithosphere stretched and thinned (Flexer et al., 2000), and clastic, carbonates and evaporites were deposited in grabens throughout the Levantine Basin.

2.1.1.2 Passive Margin Phase and Subsidence

During the Middle Jurassic to Late Cretaceous, the basin was in a passive continental-margin setting. This phase was characterised by normal faulting, sub-parallel to the present-day East Mediterranean coastline, and basin subsidence. The area was dominated by shallow to deep-marine carbonate deposition, alternating with clastic on the basin margin resulting from recurring cycles of marine transgression and regression associated with sea-level change (Flexer et al., 1986; Gardosh, 2002).

2.1.1.3 Convergence

Late Cretaceous to Tertiary convergence was due to the convergence of the African and Eurasian plates and the closure of the Neotethyan Ocean. This resulted in the inversion of the Early Mesozoic NE-trending grabens within the Levant Basin and to strike-slip faulting due to differential plate motion. This convergence phase was associated with uplift, widespread erosion and slope incision in response to sea-level fall and basin-ward sediment transport typified by submarine fan systems. The Oligocene-Miocene submarine fan systems form the reservoirs of all the commercial hydrocarbon discoveries to date within the Levantine Basin.

At the end of the Miocene, the Mediterranean Sea became isolated from the Atlantic Ocean, which led to the deposition of up to 1,500 m of evaporites in the Levantine Basin (Gradmann et al., 2005). This event lasted about 1.5 million years, and is known as the "Messinian Salinity Crisis" (Butler et al., 1999). The crisis was followed by inundation of the basin with oceanic waters and Pliocene to Recent sedimentation.

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The present-day Levantine Basin can be described as a foreland basin on the African Plate. To the north the thrust belt caused by the Africa-Eurasia plate collision is seen in the Cyprus Arc (or Larnaca/ Latakia Ridge system). In total about 14,000 metres of Mesozoic to Recent sediments were deposited in the Levantine Basin.

2.2 Offshore Israel Exploration History

2.2.1 Early Exploration History

The early exploration of the Levantine Basin, Offshore Israel targeted Plio-Pleistocene sediments in medium water depths. Notable wells were Noa-1 which was spudded in 1999, followed by Mari B-1 in 2000, both of which were operated by Noble Energy. Both have ultimately been deemed to be commercial discoveries, with Marr-B first gas in 2004 and the subsequent tie-in of the Noa and the Pinnacles discovery in 2012.

2.2.2 Recent Exploration History

Exploration in the Miocene of the deep-water pre-salt of the Israel offshore began in 2009 with the Tamar and Dalit discoveries (Tamar-1 and Dalit-1 respectively), with Tamar (10tcf 2P Reserves) being developed and on production by 2013.

These 2009 discoveries were followed by the Leviathan discovery (20tcf 2C Resource) drilled by Noble Energy in 2010 which is currently advancing towards development. In 2011 the Dolphin discovery well was completed by Noble, with Tanin-1 and Karish-1 following in 2012 and 2013 respectively.

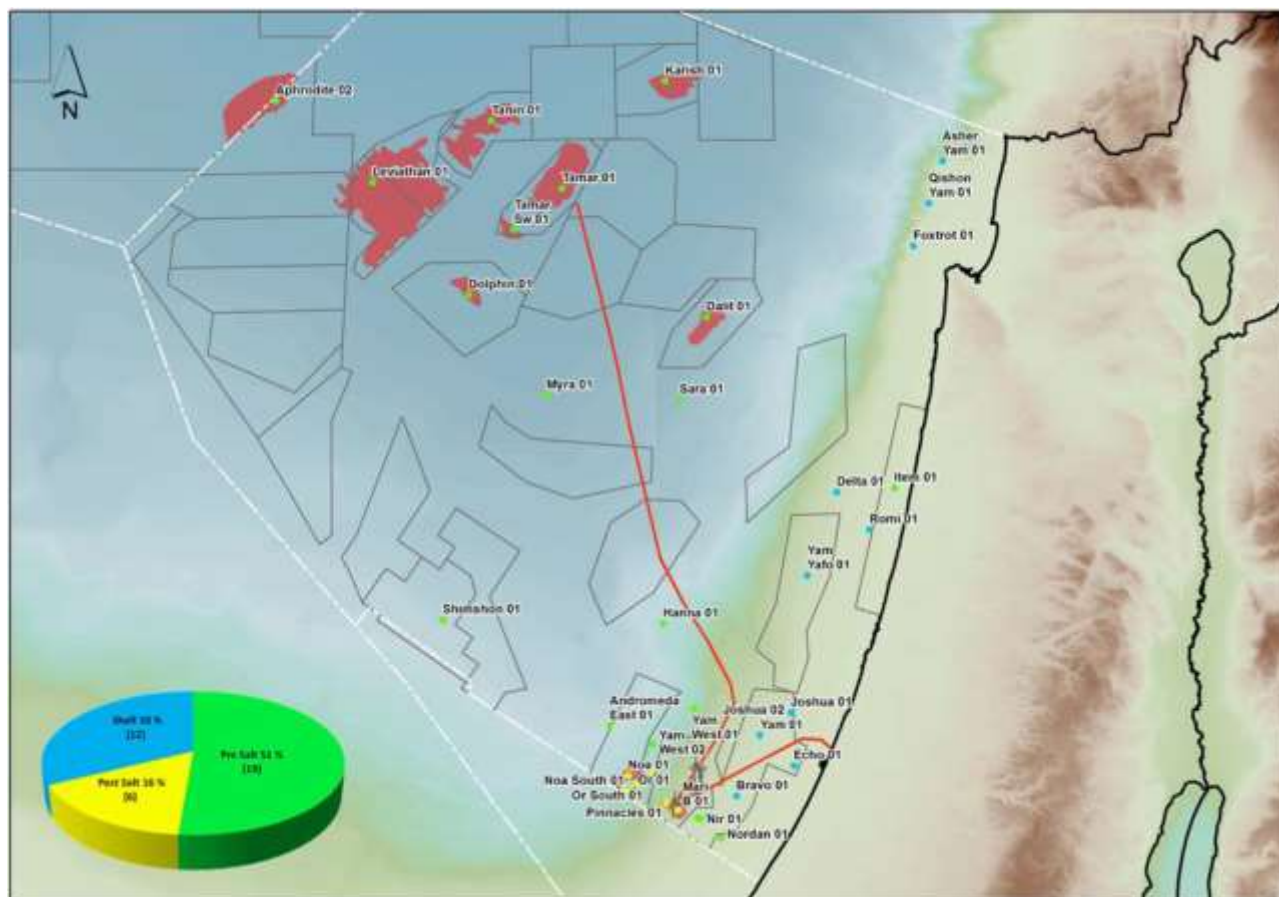


Figure 2-2 Exploration Activity, Onshore/Offshore Israel

2.3 Karish and Tanin Exploration Wells

2.3.1 Karish-1 Summary

2.3.1.1 Introduction

The Karish field was evaluated in 2013 via a single discovery well (Karish -1) which was drilled to penetrate stacked marine basin floor sands identified on seismic which had also been drilled in the Tamar and Leviathan wells.

Table 2-1: Karish-1 Surface location

ACTUAL RIG LOCATION: KARISH -1			
Rig Floor Elevation		1762m above ML (24m above MSL)	
WGS84		UTM, Zone 36N (CM 33°E)	
Latitude	33° 13' 06.687" N	Easting	619 645.0
Longitude	034° 17' 02.075" E	Northing	3 676 247.4
Position is 3.3m @ 218.9° T (218.2° G) from intended location.			

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2.3.1.2 Karish -1 Well History/ overview.

The Karish -1 well was drilled from the Ensco 5006 semi- submersible drilling unit, spudding the well on 22nd March 2013. The drilling programme consisted of jetting a 36" conductor to 1,834m MD (71m BML) before unlatching the Drill Ahead Tool (DAT) and drilling the 26" interval to 2,615 m MD. The 20" surface casing was then run and cemented at 2,600m MD. The 17.1/2" interval was drilled to 3,178 m MD, with the 13.5/8" intermediate casing set at 3,164m MD. This interval was followed by a 12.1/4" section which was drilled to 4,279m MD before setting the 10.3/4" x 9.5/8" production casing at 4,264m MD. The 8.1/2" interval was drilled through the target reservoir to 4,812 m MD before running a GR/ RES/ DEN/ NEU/ SONIC wireline evaluation log followed by a Star/ CBIL/ GR, MREX/ GR, RCI/ GR, VSP/ GR and PSWC wireline logs. On completion of the evaluation the well was temporarily plugged and abandoned before the drilling unit was moved off location.

Table 2-2: Karish-1 Well Data

ITEM	DESCRIPTION
Country / Region	Offshore Israel
License	Alon C
Well Name	Karish -1
Well Classification	Exploration
New Well / Side-track / Slot Recovery	New Well
Objective	Appraise Miocene/Oligocene sands equivalent to Tamar and keep as a future producing well.
Field Operator during well construction	Noble Energy (Mediterranean) Limited
Well Operator during well construction	Noble Energy (Mediterranean) Limited
Drilling Unit	The ENSCO 5006 (previously PRIDE NORTH AMERICA) is a column-stabilized moored semi-submersible drilling unit capable of operating in moderate environments and water depths up to 7,500 ft. using 18¾in 15,000 psi BOP and 21in OD marine riser.
Casing Programme	36", 20", 13.5/8", 10.3/4" x 9.5/8"
Elevations	Water Depth – 1,738 m RKB – 24m AMSL RKB-ML – 1,762 m
Total Depth	TD: 4812m MD/TVD -4788m TVDSS
Project Start Date	March 15, 2013 19:00 hours
Project Finish Date	June 1 2013 00:00 hours
Depth Measurement Units	Metric
TD Location	X: 619,648.03M E Y: 3,676,270.96 N (WGS84 UTM 36North)
Reservoir Target/Depth	Miocene/Oligocene sands equivalent to Tamar / 4337m MD/TVD
Target Tolerance Polygon	The target tolerance at the top of the A Sand is 398.5m by 1100m polygon oriented NW-SE around the target location
Rig Heading	289.2° True / 288.5° Grid. A North-westerly heading is preferred for prevailing weather and communication.
Directional	Vertical Well
Current Well Status	Temporary Abandonment

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2.3.1.3 Operational Description.

The Ensco 5006 moved from the Leviathan field to the Karish-1 location on March 15, 2013 at 19:00 hours. The rigs anchors were then run and cross tensioned. The well was successfully spudded on March 22, 2013 at 05:00 hours.

2.3.1.3.1 36" Interval

The 36" conductor was jetted in from 1,762m (mud line) to 1,833.5 m (71.5 m BML) with 3.0 m stick-up above the seabed. The conductor was then allowed to soak for 6 hours. While attempting to release the DAT from the wellhead, it was found the Safety Lock and Pin had been left in the DAT. Attempts to remove the Safety Lock and Pin with the ROV proved unsuccessful. The DAT was then released from the LPWHH and tripped to surface and laid down. This incident incurred 0.46 days of NPT.

2.3.1.3.2 26" Interval

The 26" interval was drilled with a Baker Hughes Auto Trak X-Treme (RSS + PDM) assembly with OnTrak II MWD/LWD BHA and Hughes VG-C1 mill tooth bit from 1,833.5 m to 2,615 m MD, section TD. The top of evaporite (anhydrite) was encountered at 2,132 m and the top of massive salt was encountered at 2,167 m. The last 115m of this section was drilled with 10.0 ppg NaCl saturated brine WBM. At 2,140m MD the BHA started to build inclination, probably due to washout around the AutoTrak ribs in the salt formation. The RPM and WOB were increased to maximize ROP and attempt to minimize wash out. A significant interbed was encountered at 2,278 m (ME60) and another at 2,469 m (ME50). At section TD, 15.8 ppg displacement mud was spotted in the rathole followed by 11.8 ppg PAD mud and the drilling assembly tripped out of hole.

The 20" casing was then picked up and ran in hole to 2,600m, with no indication of hole problems, and cemented back to the mud line with 2,292 bbls Econolite Lead mixed at 12.5 ppg and 878 bbls Class G Tail mixed at 15.8 ppg with full returns. Approximately 720 bbls cement circulated to mud line.

Whilst performing between well BOP maintenance, it was discovered that extensive repairs were required due to the pipe ram and annular operators leaking because of rust debris from the subsea accumulator bottles. In addition, the riser and BOPs had to be tripped to repair the Dead Man System. These incidents resulted in 20.5 days of NPT. Once rectified the BOP stack was run, landed and latched before completing a full BOP test.

2.3.1.3.3 17-1/2" Interval

The Baker Hughes AutoTrak X-Treme (RSS + PDM) 17-1/2" BHA was picked up and RIH with OnTrak II MWD/LWD and a Smith Mi813 LHPX PDC bit. The wellbore was displaced from seawater to 11.3 ppg Salt Saturated WBM. The shoetrack cement and 3m of new formation was drilled out and a formation integrity test (FIT) was attempted to 12.3 ppg equivalent mud weight (EMW). However, leak-off was observed at 12.0 ppg EMW.

The 17.1/2" interval was drilled from 2,618 m to 2,808 m MD. Erratic weight on bit was observed from 2,806 m to 2,808 m (fault) and then bit weight went to zero. A flow check was then conducted and 12 bbl/ hr losses were recorded. An 86 bbl LCM pill (40 ppb) was then spotted. A trip was performed to 2,584 m (inside the 20" shoe) and observed static losses of 0.8 bbl/ hr before circulating and conditioning the mud system at 900 gpm with 25 bbls / hr losses. Then the pumps were shut down and static losses of 16 bbls / hr were observed. A trip was then performed back in hole to 2,807 m and a 102 bbl LCM pill (40 ppb) spotted. Another trip was performed out of hole to 2,695 m, the well was then observed to be static and again the mud system was circulated and conditioned at 980 gpm with 10 bbl / hr losses recorded. The BHA was tripped in hole and continued drilling to 3,178m MD, section TD. During drilling a loss rate of 4-5 bbl / hr was recorded however the well was static on connections. Counteracting losses incurred 8.5 hours of NPT. A significant interbed was encountered at 2,715m (ME40) and at 2,966m (ME30). The section was drilled with excellent verticality and low tortuosity

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(maximum inclination 0.19° with maximum DLS 0.18°/30m). The entire section was drilled with 11.3 ppg surface mud weight with an average ESD 11.4 ppg and maximum ECD 11.6 ppg.

Once the drilling assembly was recovered, the wireline unit was rigged up and a suite of evaluation logs were run (GR, Bore Hole Calliper and Temperature). The wellbore hole size calliper showed the salt section washed out to on average 17.84", close to a gauge hole.

The 13.5/8" casing was then ran in hole to 3,164 m MD and cemented with 348 bbls Econolite Lead mixed at 12.5 ppg and 150 bbls Class G Tail mixed at 16.0 ppg, displacing with 11.7 ppg Salt Saturated - WBM with full returns. The plug bumped with 1500 psi and the floats were observed to hold. The top of cement was estimated at 2,250m MD, based on final displacement pressure. The 13.5/8" seal assembly was set and pressure tested to 5,300 psi without incident. Upon pressure testing the BOPs the wear bushing assembly was then picked up and RIH but was unable to release from the running tool. The wear bushing was inspected but no damage was noted. The backup wear bushing was then ran and installed without further issue. This incident incurred 13.5 hours NPT. The casing was then tested to 5,100 psi with 11.7 ppg mud weight.

2.3.1.3.4 12.1/4" Interval

The 12.1/4" BHA consisted of an AutoTrak X-Treme (rotary steerable tool with motor) with OnTrak II MWD/LWD and Smith MDSi 616X PDC bit. This assembly was picked up and RIH and the cement in the shoe track was drilled out along with 3m of new formation. A formation integrity test (FIT) was then performed to 12.4 ppg equivalent mud weight (EMW).

The interval was then drilled from 3,183 m to 4,279 m (section TD) with an average ROP of 27 mph. A significant interbed was encountered at 3,293 m (ME20). The base of the Massive Salt was exited at 3,548 m and base of Evaporite drilled at 3,555 m. The assembly encountered the tops of the MM0 (Tortonian), MM1 (Tortonian), MM2 (U. Serravallian) and MM3 (U. Serravallian) at 3,577 m, 3,605 m, 3,708 m and 3,751 m, respectively. A wiper trip was then conducted at 3,900m back to the 13.5/8" casing shoe without any excessive drag or fill noted. The Serravallian Hard streak was encountered at 4,130 m and Mid Miocene Unconformity / Bet Guvrin at 4,200 m. The BHA recorded low vibration along the whole run, only rarely experiencing stick-slip vibration while drilling lithology changes which disappeared without any actions. The section was drilled with excellent verticality and low tortuosity (maximum inclination 0.06° with maximum DLS 0.04°/ 30 m). The entire section was drilled with 11.7 ppg surface mud weight with an average ESD 11.8 ppg and maximum ECD 12.1 ppg.

The drilling BHA was POOH and wireline logging commenced, a Grand Slam (GR/RES/DEN/NEU/SONIC) wireline logging suite was run. The bore hole calliper showed the borehole washed out to an average hole diameter of 12.51", near gauge hole.

The 10.3/4" x 9.5/8" tapered casing string was then ran in hole to 4,264 m MD and cemented with 143 bbls Econolite Lead mixed at 12.5 ppg and 150 bbls Class G Tail mixed at 15.8 ppg, displacing with WBM with full returns. The plug was bumped with 2,000 psi (1,000 psi over final displacement pressure) and the floats held. The estimated top of cement based on final lift pressure is 3,100 m (64 m inside 13.5/8" casing). The 10.3/4" seal assembly was then set and pressure tested to 5,000 psi for 30 minutes. A BOP test was then completed before excess 5.1/2" drill pipe was laid down and 5" drill pipe picked up to drill 8.1/2" hole section. The 10.3/4" x 9.5/8" casing was then pressure test to 4,645 psi for 30 minutes.

2.3.1.3.5 8.1/2" Interval

The 8.1/2" Baker Hughes rotary BHA with OnTrak II MWD/LWD and Hughes HC506Z PDC bit was picked up and ran in hole and drilled cement, shoe track and 3m of new formation. A leak-off test was then performed to 13.15 ppg equivalent mud weight.

Drilling then continued from 4,282 m to 4,812 m (section TD) with an average ROP of 27 mph. This included a section of controlled ROP at 25mph to keep ECD under limits. The rotary assembly built up to 2.5° inclination

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with the horizontal displacement increasing from 7 m to 23 m (16m in 533 m MD with a maximum dog leg of 0.32°/30 m) but the wellbore remained within the driller's target. The entire section was drilled with 11.3 ppg surface mud weight with an average ESD 11.4 ppg and maximum ECD 12.2 ppg. With a TD pore pressure of 10.0 ppg, an 11.4 ppg ESD mud weight resulted in a maximum overbalance of 1,150 psi.

The drilling BHA was then POOH and wireline logging was conducted with a Grand Slam (GR/RES/DEN/NEU/SONIC) wireline logging suite. The bore hole calliper showed the borehole washed out to an average hole diameter of 8.6", near gauge hole. A further wireline run of Star/CBIL/GR, MREX/GR, RCI/GR, VSP/GR and PSWC was completed without any major issues. The RCI pressure data through the reservoir overlaid the original Karish-1 predicted pore pressure curve.

2.3.1.3.6 Temporary Abandonment

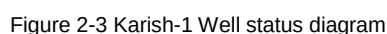
To temporarily abandon the well, a 3.1/2" cement stinger with a half mule shoe was run and two 8.1/2" open hole cement plugs were set across the reservoir from 4,812 m (TD) to 4,500 m (tagged at 4,572 m with 5 kips) and 4,572 m to 4,200 m, 64 m inside 9.5/8" casing (tagged at 4,198 m with 5 kips and successfully pressure tested to 1,000 psi), respectively. The wellbore was then displaced from the second cement plug (kick-off plug) up to 2,250 m MD with 13.9 ppg mud weight to replace riser margin and provide a hydrostatic equal to or greater than pore pressure (10.8 ppg at 4,264 m) plus 350 psi with seawater to mud line or 11.3 ppg EMW.

Wireline was then rigged up and a Cement Bond Log/Junk Catcher/Gauge ring run was made. The logging string was run from 4,175 m to 3,550 m, recording the top of 15.8 ppg Class G Tail slurry at 3,586m but was unable to determine the top of 12.5 ppg Econolite Lead slurry (estimated top of cement 3,100m based on final lift pressure, 64 m inside 13.5/8" casing). A 9.5/8" Halliburton EZ-SV (Bridge Plug) was then set at 4,168 m WL (30 m above top of cement) and successfully pressure tested to 1,600 psi for 15 minutes.

The 3.1/2" cement stinger with half mule shoe was run again and a 13.9 ppg high-viscosity pill was set from 2,250 m to 2,150 m and then a 100m surface cement plug was set from 2,150 m to 2,050 m with 30 bbls of Class G cement mixed at 15.8 ppg, leaving 100 m (30 bbls) of 13.8 ppg spacer on top of the cement and 11.3 ppg WBM above spacer to the mud line.

The wear bushing was then retrieved and the wellbore and casing hanger seal assembly was successfully negative pressure tested (900 psi) with a seawater gradient to the mudline for 30 minutes. The BOP and riser was then disconnected and secured on the beams.

The anchors were then pulled and bolstered and the Ensco 5006 departed Karish-1 location at 00:00 hours on 1-June-2013.



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2.3.2 Tanin-1 Well Summary

2.3.2.1 Introduction

The Tanin field was evaluated in 2011/12 via a single discovery well (Tanin -1) which was drilled using the Pride North America to evaluate a complex four-way dip closed faulted anticline in 1,773 m of water depth in the Alon A license area. The well was designed to penetrate stacked marine basin floor sands identified on seismic, and penetrated in the Tamar-1, Tamar 2, and Leviathan-1 wells where they are dated as late Oligocene to early Miocene.

Table 2-3: Tanin-1 Surface location

ACTUAL RIG LOCATION: TANIN -1			
Rig Floor Elevation		1797m above ML (24m above MSL)	
WGS84		UTM, Zone 36N (CM 33°E)	
Latitude	33° 08' 28.703" N	Easting	580 485.6
Longitude	033° 51' 46.615" E	Northing	3 667 283.7
13m on a bearing of 150° T from the proposed location			

2.3.2.2 Tanin -1 Well History/overview.

The Tanin -1 well was drilled from the Pride North America (subsequently the Ensco 5006) semi- submersible drilling unit, spudding the well on 9th December 2011. The drilling programme consisted of jetting a 36" conductor to 1,868m MD before unlatching the Drill Ahead Tool (DAT) and drilling the 26" interval to 2,937 m MD. The 20" surface casing was then run and cemented at 2,922m MD below the ME50 within the Evaporite. The 17.1/2" interval was drilled to 3,663 m MD, with the 13.5/8" intermediate casing set at 3,146m MD. This interval was followed by a 12.1/4" section which was drilled to 4,636m MD before setting the 9.5/8" production liner at 4,634m MD. The 8.1/2" interval was drilled through the target reservoir to 5,528 m MD before running a comprehensive wireline logging programme. On completion of the evaluation, the well was temporarily plugged and abandoned before the drilling unit was moved off location.

Table 2-4: Tanin-1 Well data

ITEM	DESCRIPTION
Country / Region	Offshore Israel
License	Alon A
Well Name	Tanin 1
Well Classification	Exploration
New Well / Side-track / Slot Recovery	New Well
Objective	Appraise Miocene/Oligocene sands equivalent to Tamar & Leviathan
Field Operator during well construction	Noble Energy (Mediterranean) Limited
Well Operator during well construction	Noble Energy (Mediterranean) Limited
Drilling Unit	The PRIDE NORTH AMERICA (subsequently the ENSCO 5006) is a column-stabilized moored semi-submersible drilling unit capable of operating in moderate environments and water depths up to 7,500 ft. using 18¾in 15,000 psi BOP and 21in OD marine riser.
Casing Programme	36", 20", 13.5/8", 9.5/8" liner
Total Depth	TD: 5528m MD/TVD -5504m TVDSS
Project Start Date	December 4, 2011
Project Finish Date	February 27 2012
Depth Measurement Units	Metric
TD Location	X: 580 485.6m E Y: 3,667,283.7m N

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	(WGS84 UTM 36North)
Reservoir Target/Depth	Miocene/Oligocene sands equivalent to Tamar / 5054m MD/TVD
Target Tolerance Polygon	282.8m square oriented NW-SE around the target location
Rig Heading	North-westerly / 300° T is preferred for prevailing weather and communication.
Directional	Vertical Well
Current Well Status	Temporary Abandonment

2.3.2.3 Operational Description.

The Pride North America reached the location on the 4th December 2011 where the anchors were run and cross tensioned without incident. The well was successfully spudded on the 9th December.

2.3.2.3.1 36" Interval

The 36" casing and 26" drilling assembly was made up on the Drill Ahead Tool (DAT) and run on drill pipe to the mud line. The casing string tagged the seafloor at 1,797m MD. The 36" casing was jetting to 1,868m, 71m below the mud line. The casing was jetted in place using seawater and high viscous sweeps. No problems were encountered. The casing was then allowed to soak for 6 hours before releasing the DAT.

2.3.2.3.2 26" Interval

This section was drilled down to 2,858 m using a Baker HCC mill-tooth bit with seawater and high viscous sweeps (pre-hydrated bentonite and guar gum). The remainder of the hole section, to 2,937 m, was drilled using a 10.0 ppg NaCl saturated brine and sweeps. Salt saturated brine was used to minimize washout and leaching of the salt where the 20" casing shoe would be set. After drilling to casing point, a 300 bbls salt saturated high viscous sweep was pumped and the circulated around. A short trip was made to 1,870 m, just outside the 36" casing shoe. On the trip back to bottom the BHA had to be reamed down from 2,858 m to 2,937 m (TD). Another 300 bbls high viscous sweep was pumped and the well was displaced to 11.6 ppg PAD mud. The 26" BHA was pulled from the well and a calliper log was run on wireline. The calliper log showed the last section drilled with brine was in gauge.

The 20" casing was picked up and ran to 2,922m, with no indications of hole problems. The casing was cemented back to the mud line via an inner string with Econolite Lead mixed at 12.5 ppg and Class G Tail mixed at 15.8 ppg with full returns achieved.

2.3.2.3.3 17.1/2" Interval

Upon landing and latching the BOP, the BSR could not be opened with the yellow POD, which meant the riser and BOP had to be pulled back to surface, the pod repaired and BOPs re-run. This issue resulted in 8 days NPT.

The wellbore and riser were displaced with 11.0 ppg salt saturated NaCl/ KCl mud. The cement, float equipment, rat hole and 3m of new formation were drilled out and a FIT was performed to 12.6 ppg. At this point the BHA (Baker HCC PDC bit, MWD with mud motor) was pulled out and replaced due to a MWD tool failure. The mud system was weighted up to 11.8 ppg prior to resuming drilling. The 17-1/2" hole section was then drilled ahead to 3,663 m (TD) at an average ROP of 20 mph with no further issues. At section TD, the hole was flushed with a 200 bbls hi-vis saturated salt polymer pill before 25 bbls of 16.0 ppg mud was spotted in the rat hole. The drilling assembly was then tripped out of hole without encountering any problems.

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The 13-5/8" casing was successfully run and cemented to 3,648 m, 15 m above interval TD. The casing was successfully cemented to the top of the salt section with a 12.5 ppg lead and 16 ppg tail cement design. An upper and lower plug system was used to place the cement. A subsequent cement bond log showed the top of the tail cement but did not pick up the top of the lead cement.

2.3.2.3.4 12.1/4" Interval

The 12.1/4" BHA consisted of a AutoTrak rotary steerable tool with OnTrak MWD/LWD and Baker HCC PDC bit. This section was drilled with mud used in the previous hole section converted to a salt saturated NaCl/KCl/GEM GP/CLAYSEAL PLUS polymer system. The fluid was also weighted up from 11.8 ppg to 12.0 ppg. The cement, float equipment, rat hole and additional 3m of new formation was drilled out and a FIT was performed to 13.08 ppg. The section was drilled to 4,634 m MD, with a maximum inclination of 0.18°. The average ROP was 10 mph with erratic ROPS seen during the interbedded shale and sand sections, these did not damage the bit however with a final dull grading of 1-1. Short trips were made on ~500 m of new hole drilled or every 24 hours. Back-reaming was required on short trips due to tight hole. At section TD, the hole was flushed with a 200 bbl hi-vis pill and circulated until the shakers cleaned up. Back reaming was required back to 4,233 m. Hard fill (9 m) was noted on the trip back to bottom before another 140 bbls high viscosity sweep and two bottoms up were circulated. The final trip out went without issue. A 9-5/8" liner was then run to depth with no hole problems.

The liner was cemented with a single 15.9 ppg slurry. Issues were encountered during the displacement when the plug did not bump after the theoretical volume. Subsequently, upon releasing the liner running tool 100bbls of contaminated mud, cement and spacer were circulated out and firm cement was tagged 225 m high within the liner prior to being drilled out. These factors indicated that the cement had been effectivity under-displaced.

Prior to drilling the next section a 9-5/8" liner pressure test proved unsuccessful. However, after failing to locate the leak with a retrievable packer the decision was made that the leak was not severe enough to halt drilling operations. The failed pressure test resulted in 2 days of NPT.

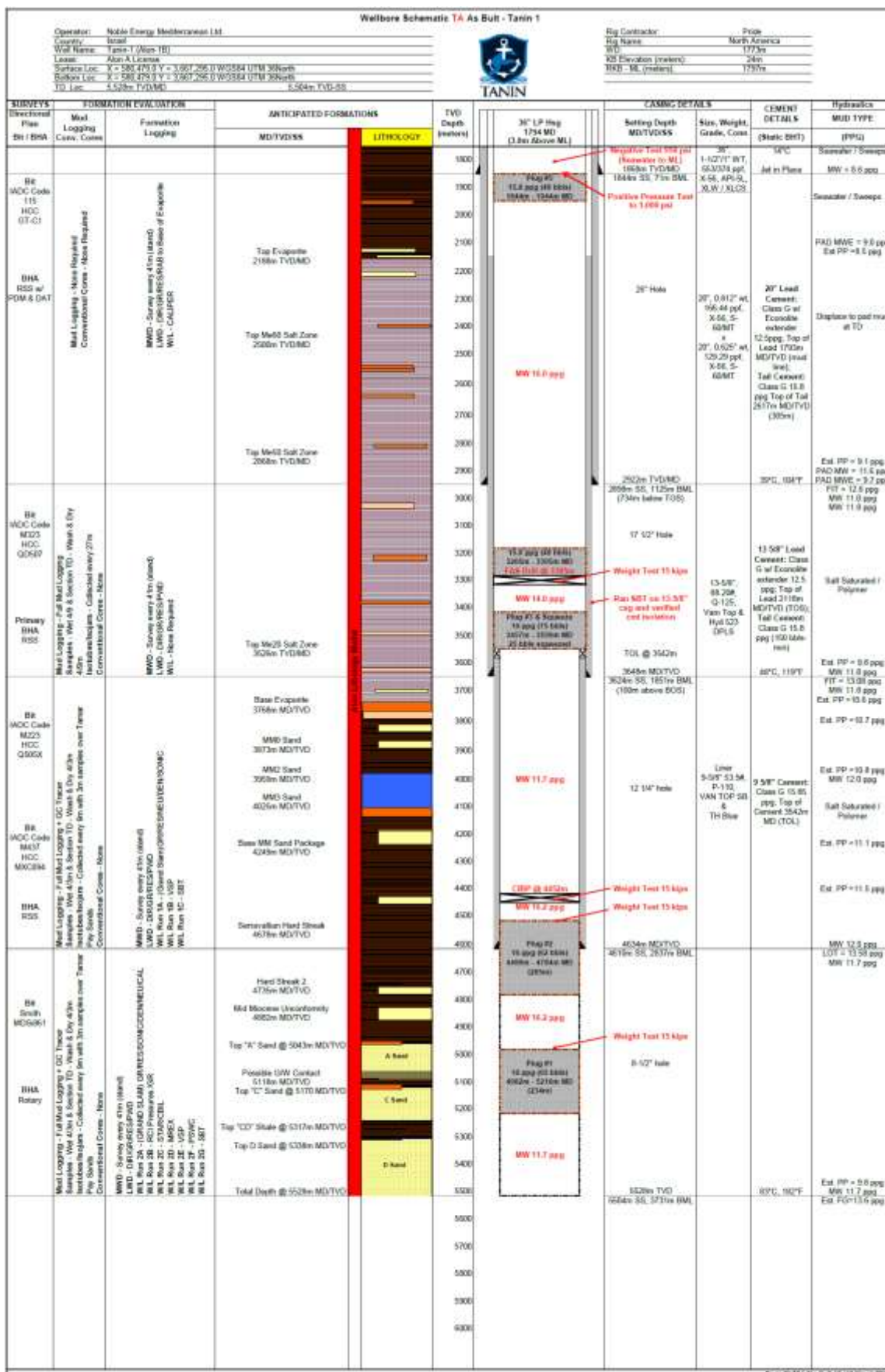
2.3.2.3.5 8.1/2" Interval

The 8-1/2" section was drilled using a rotary BHA with MWD and a Smith PDC bit. The drilling fluid was the same 11.7 ppg salt saturated NaCl/KCl/GEM GP/CLAYSEAL PLUS polymer system used in the 12-1/4" hole section. The cement, float equipment, rat hole and additional 3m of new formation were drilled prior to conducting a LOT to 13.58 ppg. The section was drilled to 5,528 m, well TD, initially at around 20 mph except when limited for formation evaluation until ROP gradually dropped to <5 mph towards TD. The bit was graded 3-1 upon recovery. A 100 bbl hi-vis pill was circulated around prior to making a short trip to the previous casing shoe. It was necessary to back ream from 5,410 m to 5,170 m but otherwise hole conditions were good. The BHA was tripped back to bottom and with another 100 bbl hi-vis pill circulated before pulling out of the hole to log. No back reaming or pumping was necessary on the final trip out of the hole. The hole was successfully logged over the next 5 days with no wiper trips required.

2.3.2.3.6 Temporary Abandonment

The wellbore was temporarily abandoned with a deep cement plug across the A and C sands with a second cement plug set across the 9-5/8" shoe with a cased hole bridge plug above. A third cement plug was set above the 9-5/8" liner top and squeezed into the liner x 13-5/8" annulus due to the liner leak and poor cement job. The liner lap was further isolated by a 4th cement plug set on a drillable plug inside the 13-5/8" casing. The temporary abandonment was completed by a 5th cement plug set shallow at 1,844 m. All plugs were suitably verified upon installation.

The anchors were then pulled and bolstered and the Pride North America departed the Tanin-1 location on 27-February-2012.



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Figure 2-4 Tanin-1 Well Status Diagram

2.4 Reservoir Geology

The discovered hydrocarbons within the Karish and Tanin Leases are contained within the Early Miocene submarine fan deposits of the Tamar sands, these are underlain by well-developed aquifer sands of Early Miocene and Late Oligocene age. A detailed discussion of the areal distribution of the reservoir units is given in Section 2.5.

The Tamar Sands are further subdivided into more detailed reservoir units (A-D Sands, with A being stratigraphically the youngest) and separated by pelagic shales interpreted to be maximum flooding surfaces, representing maximum sea levels and temporary starvation of the Levant Basin sediment supply.

The main reservoir at Karish is the massive, clean, C Sand which in Karish Main contains some 2 Tcf of gas in-place. The C Sands at Karish are c.130m TST and of outstanding reservoir quality (Section 3). The C Sands are interpreted to be extensive across the entire structure (Section 2.5.4). Excellent quality reservoir is also found in the D sand, but the gas volumes within the C Sand are estimated to be 362bcf (Karish Main) owing to the majority of these sands being limited to the aquifer.

The B Sands at Karish appear to be more distal/marginal turbidite deposits, relative to the C and D sands. This in part is thought to be due to the growth of the Karish Main structure during the early Miocene (post deposition of the laterally unconstrained C and D sands), resulting in predominantly dilute flows and fine grained sediment depositing Tamar sands over what was a bathymetric high. This results in the Sands being thinly bedded with conventional formation evaluation failing to adequately capture the true input of net reservoir sands within the B Sands (Section 3.5.5.7).

The A Sand is largely absent in the Karish-1 well, but it is expected to be present elsewhere within the Karish Complex, owing to Karish-1 penetrating the Top A Sand equivalent within a localised Middle Miocene channel scour.

The A and B sands are the only interpreted pay intervals within the Tanin Complex. The A and B sand are both well-developed 20m (TST) turbidite sands with NTG >80%. Whilst C and D sands of reservoir quality are present across Tanin, the low structural relief (c.100m), results in the C and D Sands being solely within the aquifer.

2.5 Seismic Interpretation and Mapping

2.5.1 3D Seismic Dataset

2.5.1.1 2009 East Mediterranean 3D (EMED-09)

The PGS Ramform Vanguard was contracted in 2009 to acquire a 3D seismic survey for Noble Energy and partners. The survey (EMED-09 - Figure 2-5) covered an area of 4190km² which provided full fold migrated coverage over the entire Tanin lease. The survey was shot with twelve 7050m streamers towed at 100 meter separation with two sources. The orientation of the sail lines was NW-SE.

PGS processed the dataset to Pre-STM using the 3D Kirchhoff bending ray algorithm. The output trace spacing was 12.5 x 12.5m and a trace length of 9s TWT at a 4ms sample interval.

2.5.1.2 2010 East Mediterranean 3D (EMED-10)

The PGS Ramform Vanguard was re-commissioned in 2010 to acquire a second 3D seismic survey for Noble Energy, east of the EMED-09 survey. The EMED-10 survey covered an area of 2223km² which included full fold migrated coverage over the Karish lease. The survey was shot with the same acquisition parameters as EMED-09. The orientation of the sail lines was NE-SW orthogonal to the EMED-09.

PGS processed the dataset to Pre-STM using the 3D Kirchhoff bending ray algorithm. The EMED-10 was merged post stack with the EMED-09 and re-gridded to a mega grid. The output trace spacing was 12.5 x 12.5m and a trace length of 9s TWT. The merged region of the two 3D seismic volumes is located on the SE of the Tanin lease (Figure 2-5).

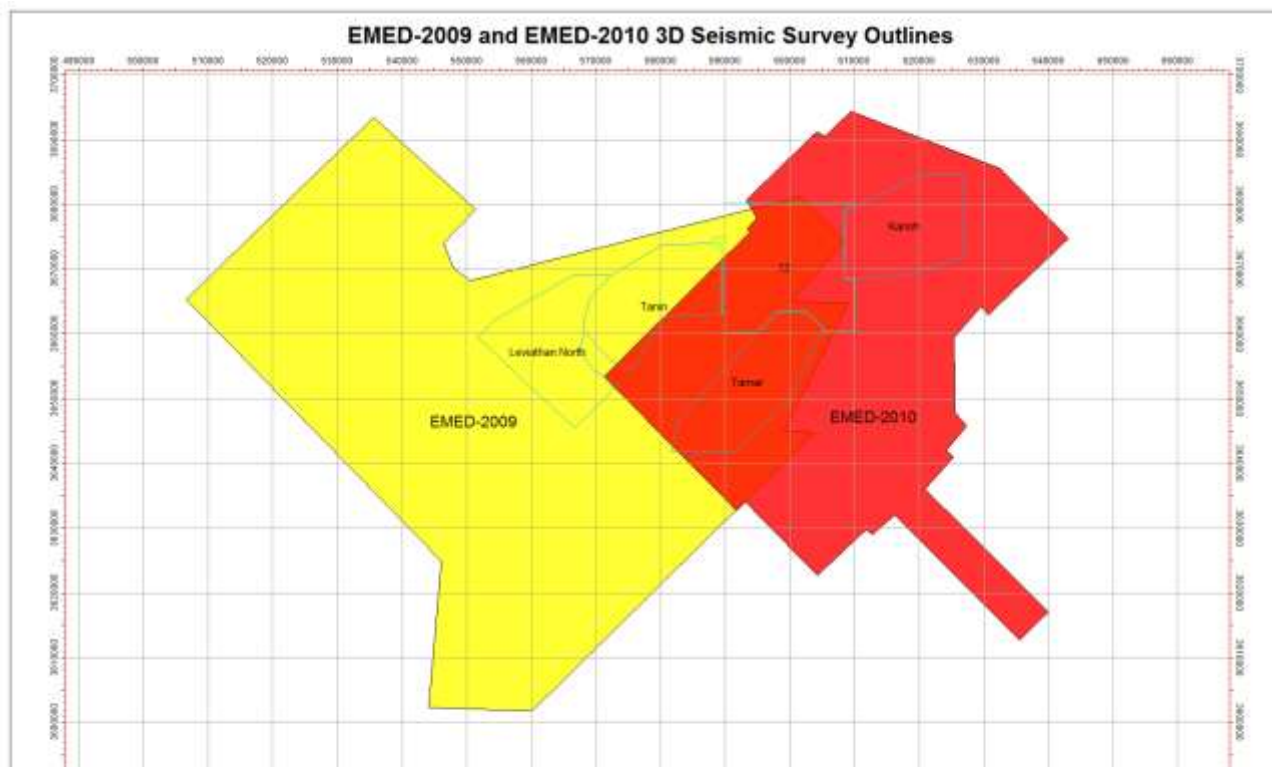


Figure 2-5 Seismic coverage.

Figure Notes: The EMED-09 seismic survey coverage in yellow. The EMED-10 seismic survey coverage in red. The post stack seismic merge zone is located SE of the Tanin lease.

The combined mega grid survey was processed to PSDM. The output square bin size was 12.5m at a trace length of 13km and a sampling interval of 5m. Subsets of the PSTM and PSDM were provided by Delek Energy covering the entire extent of both leases.

2.5.1.3 Polarity of seismic data

The seismic data was processed zero-phase. The polarity of the data is S.E.G. Normal (Figure 2-6) i.e. an increase in acoustic impedance is a zero phase peak. Figure 2-7 illustrates the seabed horizon on the PSTM and PSDM.

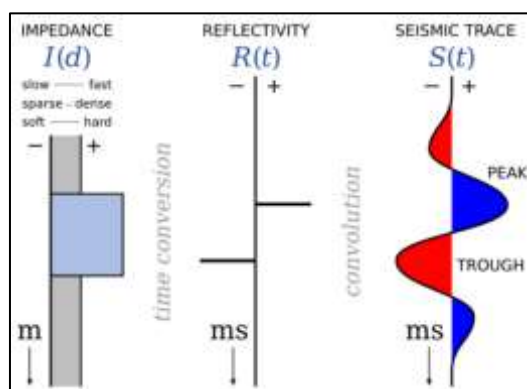


Figure 2-6 S.E.G. Normal polarity. Increase of acoustic impedance is a zero phase peak

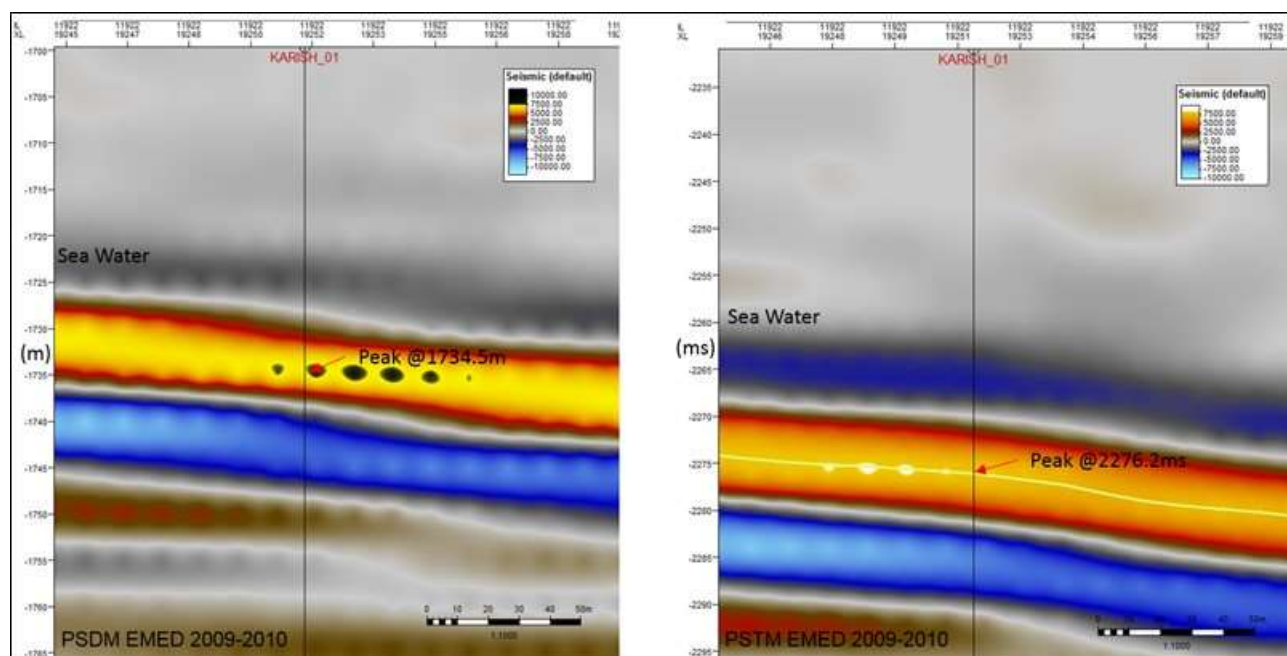


Figure 2-7 Seabed reflector.

Figure Note: Taken from the PSDM and PSTM 3D seismic volumes (inline 11922) at the Karish-1 well location. Red is a peak.

2.5.2 Synthetic Seismograms and Phase Analysis

2.5.2.1 Karish-1 Well

Baker Hughes acquired the sonic and density wireline logs over the 12.25" and 8.5" sections using the XMAC and ZDL wireline tools. Both curves were edited and spliced to produce continuous curves from 3160mMD to 4790mMD (Figure 2-8). A VSP was also acquired over the interval 4305-4765mMD, a total of 225 stations.

The compressional sonic curve was calibrated to the check-shots at lithological boundaries. The overall drift down to the base evaporite was 1ms. Below the evaporite the drift gradually decreases to -35ms. The sonic integrated time seems to be affected by the gas.

Synthetic seismograms were generated and phase matched to the surface seismic at the well location. The resulting well tie is excellent (Figure 2-8). A time shift of +10ms and a phase rotation of 15.7deg was used to match the seismic.

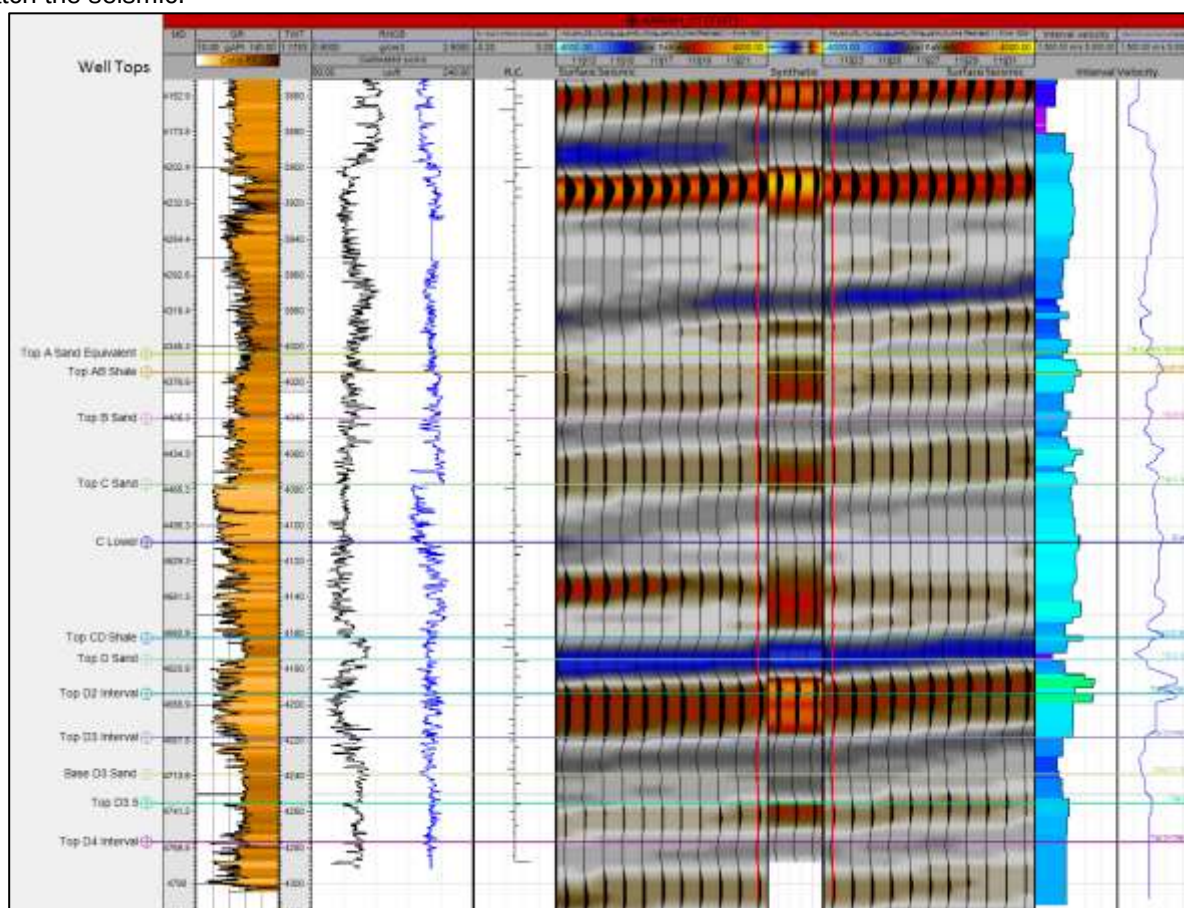


Figure 2-8 Well tie of the calibrated synthetic seismogram to the surface seismic at the Karish-1 well.

The VSFusion VSP processing report together with the composite displays are included as separate attachments.

2.5.2.2 Tanin-1 Well

Baker Hughes acquired the sonic and density wireline logs over the 12.25" and 8.5" sections using the XMAC and ZDL wireline tools. Both curves were edited and spliced to produce continuous curves from 3645mMD to

5500mMD (Figure 2-9). A VSP was also acquired in two runs over the interval 1797-4634mMD, a total of 225 stations.

The compressional sonic curve was calibrated to the check-shots at lithological boundaries. The VSP corridor stack and synthetic seismogram show an excellent match.

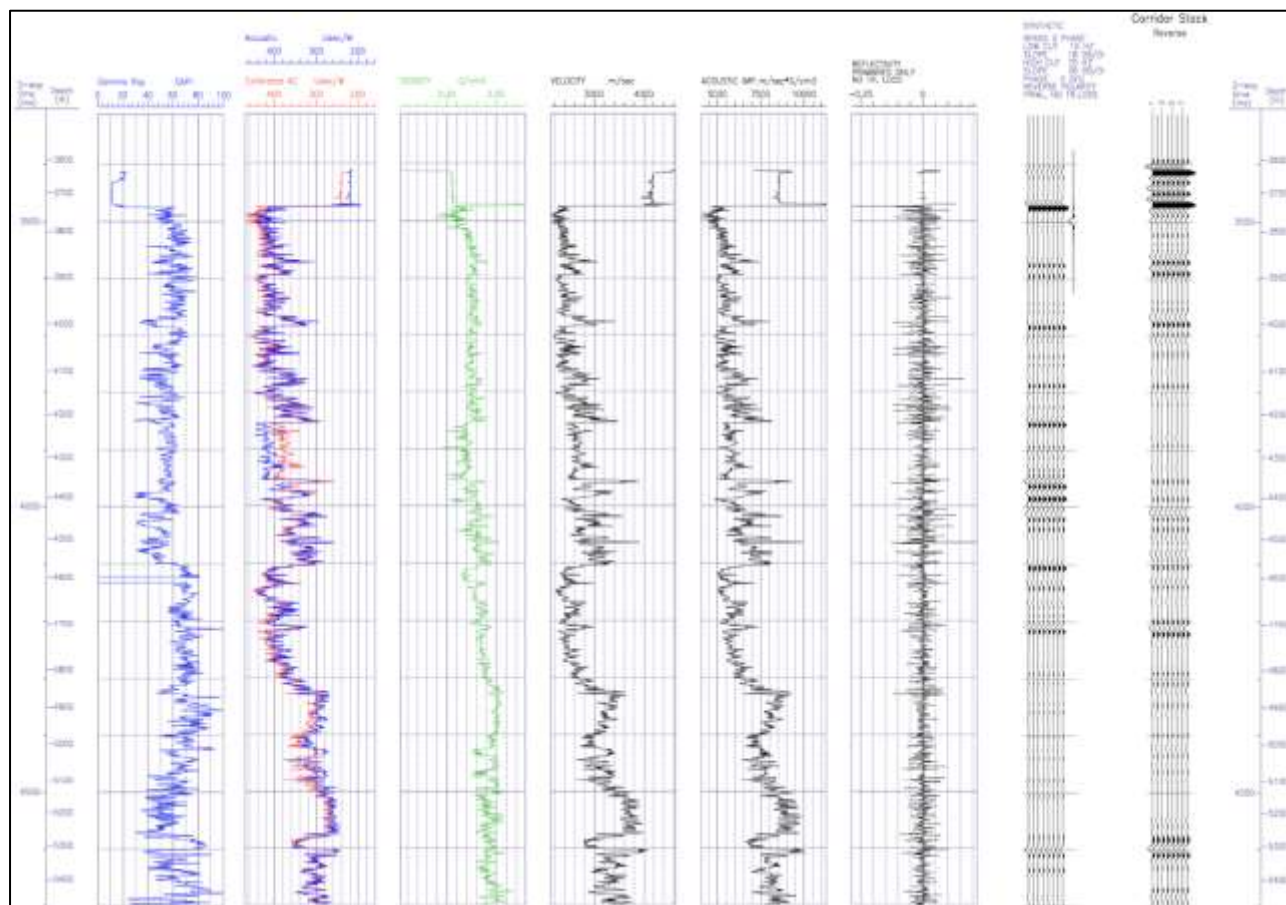


Figure 2-9 Sonic calibration.

Figure Notes: Synthetic seismogram and corridor stack (Normal S.E.G polarity) generated by VSFusion for Noble Energy.

2.5.3 Seismic Markers

2.5.3.1 Regional Seismic Markers and Seismic Facies

The regional seismic markers are consistent across both the Karish and Tanin leases. Figure 2-10 shows the seismic reflection characteristics of the seismic stratigraphic packages from Middle Jurassic to present.

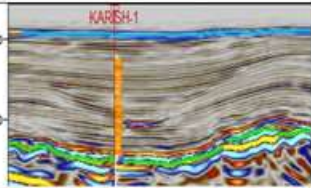
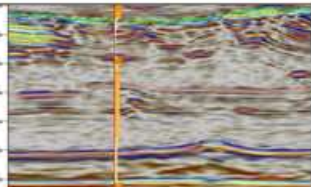
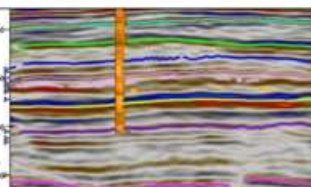
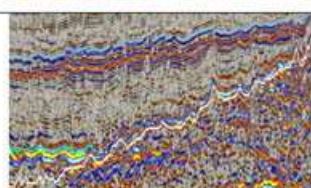
	Seismic Reflectivity	Seismic Horizon	Thickness (m)	Reflection Characteristics	Interpretation
Plio/Pleistocene		Seabed	250 to 450	Characterised by high frequency low amplitude reflectors. Subparallel wavy to lenticular configurations. Onlapping onto to structures generated by underlying salt movements.	Deep water depositional system controlled by the underlying salt movement. Strong seabed reflector
		Top Evaporite			
Messinian Evaporites		Top Evaporite	1550 to 1720	The upper interval shows discontinuous high amplitude reflectors folded and at places thrust imbricates are visible. The lower section is largely transparent with high amplitude parallel reflectors at the base of the salt.	Mobile halite dominated system with subordinate rafted clastics and evaporites. The halite mobility is gravity driven causing extensive folding and thrust imbricates.
		Intra Evaporite			
		Base Evaporite			
U. Miocene - Post Tamar Sands		Base Evaporite	900 to 2400	Predominantly extensive parallel high amplitude reflectors. The middle interval becomes more discontinuous and chaotic characterised by low amplitude reflectors	Deep water depositional system. Possible amalgamating basin floor fans
		MMUJ			
E. Miocene - Tamar Sands		MMUJ	250 to 350 A to D sands	Extensive parallel high amplitude reflectors. The upper part of the Tamar sands appears to be truncated.	Basin floor fans system
		Top Tamar Sands			
		Top B Sand			
		Top C Sand			
		Top D Sand			
Jurassic - Eocene		Top 3.5D Sand			
		Top Eocene		Parallel high amplitude reflectors are visible below the Top Eocene and Top Cretaceous horizons. Predominantly the interval is characterised by low amplitude reflectors affected by poor seismic quality.	The Cretaceous-Eocene interval onlaps onto the Jurassic highs.
		Top Cretaceous			

Figure 2-10 Seismic reflection characteristics of seismic stratigraphic packages

During Middle-Jurassic to Late-Cretaceous times the basin was in a passive continental margin setting. Clastics, carbonates and evaporates were deposited over that period. The equivalent seismic interval as shown on Figure 2-10 indicates parallel high amplitude reflectors on-lapping the Jurassic highs and overlying chaotic and discontinuous reflectivity, possibly clastics. The Middle Jurassic to Late Cretaceous interval is present over the Tanin lease but is absent over the Karish lease as it pinches-out to the west of the Lease.

Excluding the pinched out Cretaceous sequence over the Karish area the rest of the seismic sequences are extensive over both leased areas. An example seismic line is shown on Figure 2-11.

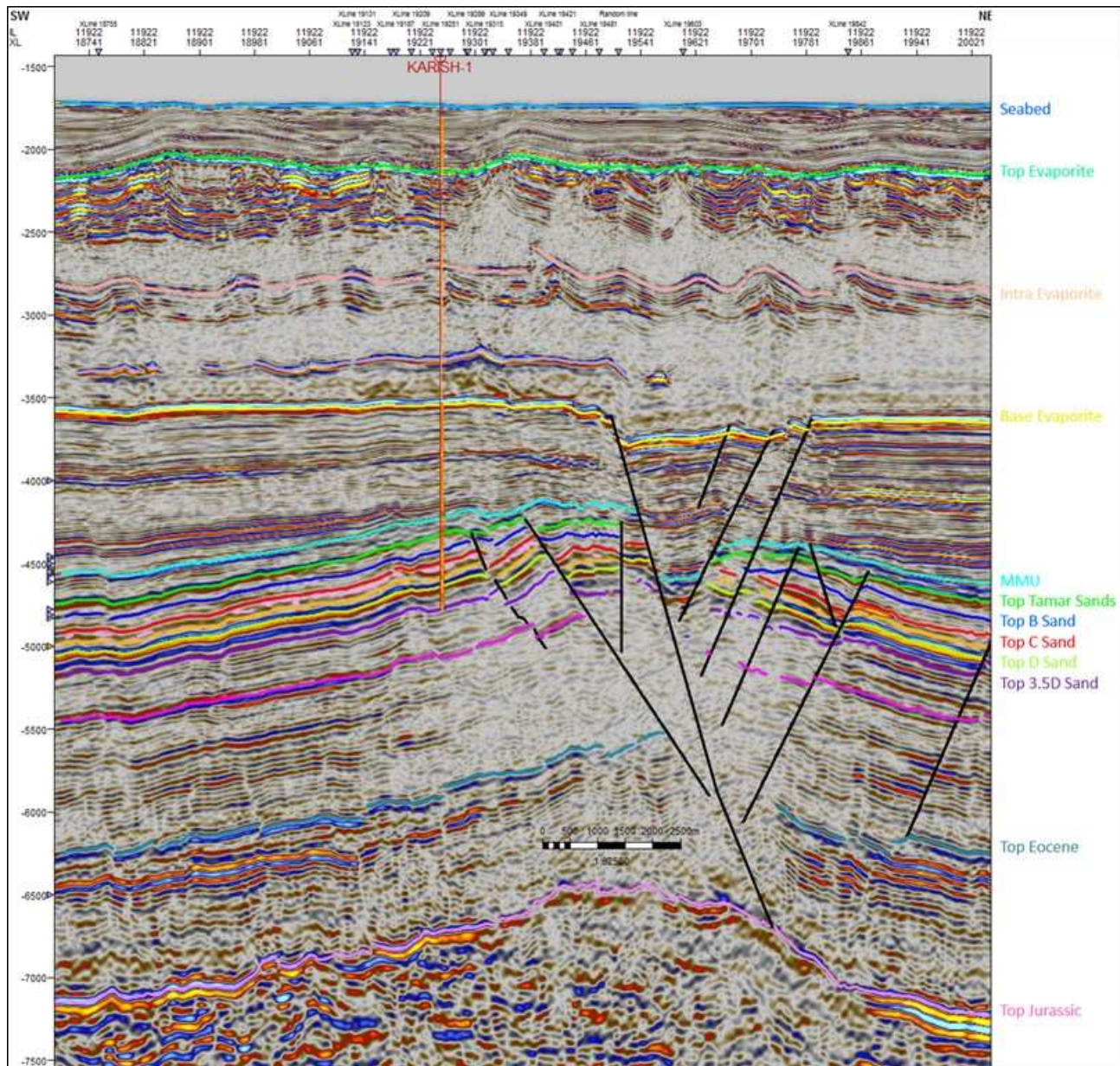


Figure 2-11 Seismic section through the Karish-1 showing the Inline 11922

2.5.3.2 Reservoir Interval Seismic Markers

The Early Miocene, Tamar Sands in the Levant Basin are sand rich, extensive, deep-water, turbidites. The Tamar sands are correlated across the Tanin-1, Karish-1 and Tamar-1 (Christiansen et al, 2013) wells. Noble/Delek has subdivided the Tamar Sands into four major sand units (A, B, C and D Sands).

The Top A Sand is missing at the Karish-1 well location. Subsequently the down truncating surface was picked on the inflection point defining the upper horizon to the Tamar Sand package. Figure 2-11 shows the Top Tamar Sands reflector also referenced in the document as “Top A Unconformity” pick.

The Top B Sand is picked on a trough (Figure 2-12). The acoustic impedance contrast across the interface is weak but clearly defined.

The Top C Sand formation top ties to the inflection point on the seismic. Due to the poor continuity of the inflection point the deeper trough (Figure 2-12) was selected for regional interpretation.

Although the Top D Sand formation top ties to a trough on the seismic the deeper inflection point was selected due to the excellent regional continuity and quality.

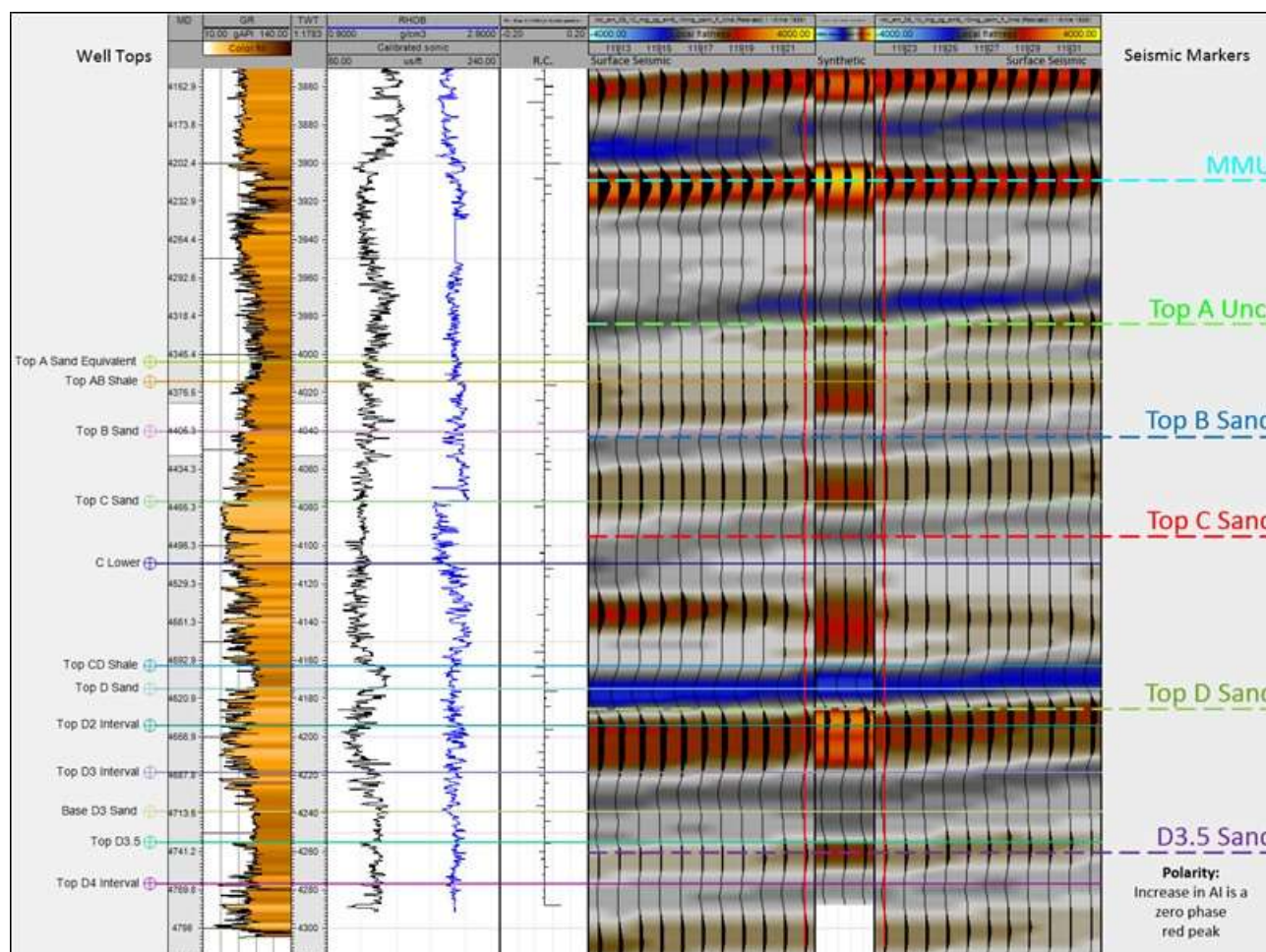


Figure 2-12 Seismic markers and formation well tops.

Figure Note: The picked seismic markers are displayed as broken lines

Two additional seismic horizons were interpreted for detailed isopach generation above and below the Tamar Sand interval. The MMU was interpreted on a peak and the D3.5 Sand on the corresponding trough

2.5.4 Karish Lease Interpretation

2.5.4.1 Horizon Interpretation

The Kirchhoff Pre-SDM 3D seismic volume was used for the interpretation of the Karish lease. Figure 2-12 explains the identification of the seismic markers associated with the individual top sand units.

The Top A Sand was absent in the Karish-1 well and possibly over most of the structural highs of the Karish Main field. Therefore the unconformity truncating downward into the A Sand was interpreted instead.

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Figure 2-13 shows minor erosional events (black lines) prior to the major unconformity. The exposed shoulders of the footwalls are affected by erosion together with the channel erosion on the corresponding hanging walls. The channel fill is composed of reworked sandstones and hemiplegic mud rich sediments. Reservoir pressure measurements taken from thin sands within the channel fill observed 50psi overpressure, indicating these thin sand layers were isolated and subsequently uplifted during the formation of the Karish structure.

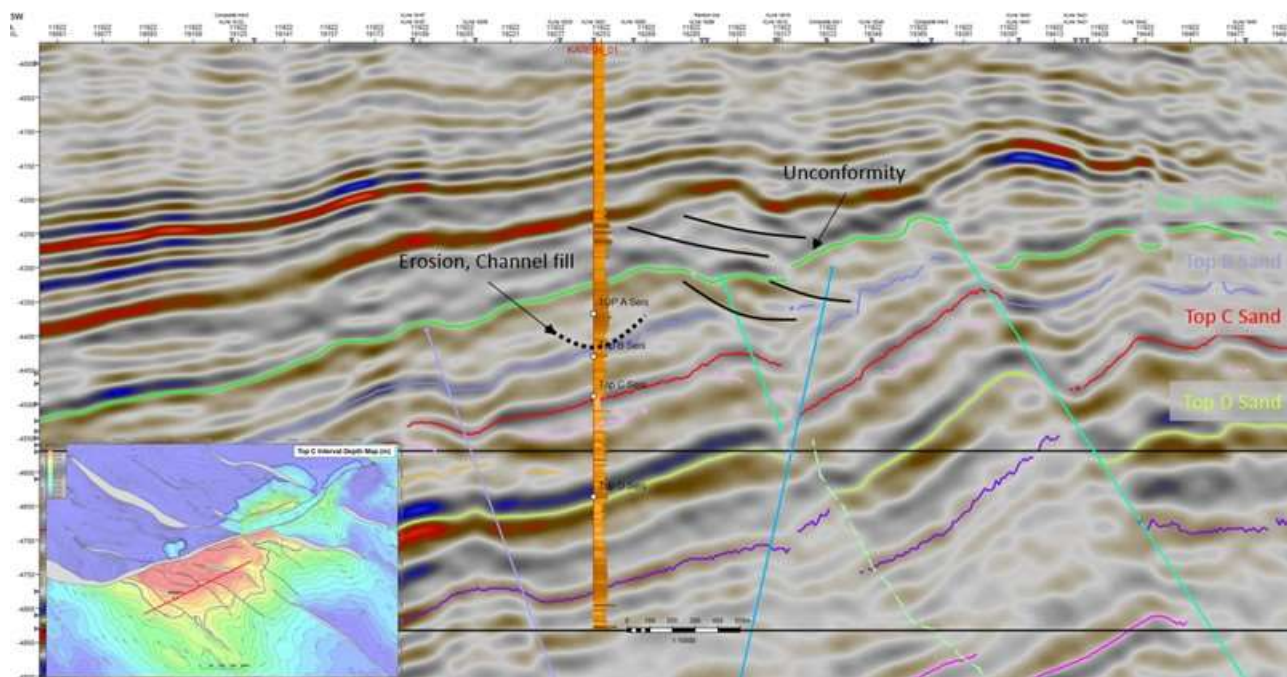


Figure 2-13 Arbitrary seismic line.

Figure Note: Eroded A Sand at the location of the Karish-1 well (broken black line)

The quality of the Top A equivalent horizon is affected by the following factors (Figure 2-14):

- The seismic quality diminishes below the fault shadow of the E-W oriented north bounding fault to the Karish field.
- Overburden lateral velocity variation affect the continuity of the Top A Unconformity reflector.
- The overlying interval on-laps the A sand. Therefore the acoustic impedance varies at the crest of the structure.
- The crest of the structure appears eroded.

The quality of the Top A Unconformity picked reflector is excellent away from the Karish structural high. The Top A equivalent surface is shown on Figure 2-18. Figure 2-19 shows the amount of the A Sand eroded

The Top B Sand horizon, shown on Figure 2-15, is picked on a low amplitude reflector affected mostly by the poor seismic quality associated with the faults as described above. The Top A equivalent and the Top D Sand horizon trends were used to generate the Top B surface. The quality of the Top B picked reflector is excellent away from the Karish structural high. The Top B surface is shown on Figure 2-20.

The Top C Sand reflector as shown on Figure 2-21 shows a weak amplitude response, the reflection strength is predominantly due to the density contrast at the interface. The reflector becomes discontinuous in the poor seismic quality areas discussed earlier (Figure 2-17). The Top C reflector is also affected close to the gas-water contact. Tuning between the Top C Sand reflector and the reflector associated with the gas-water contact causes a depth shift as shown on Figure 2-16. The depth shift is not consistent with the GWC deduced from the well.

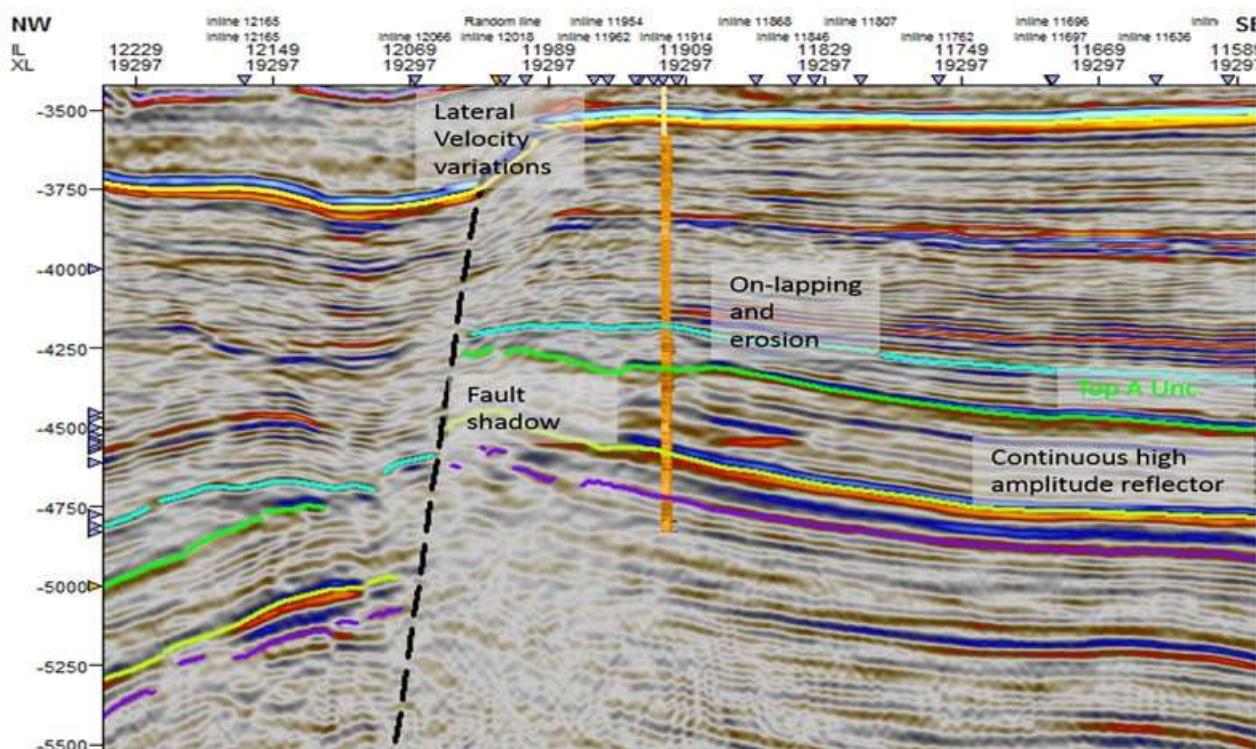


Figure 2-14 Cross-line 19297.

Figure Note: Highlighting the factors affecting the quality of the Top A equivalent horizon (green)

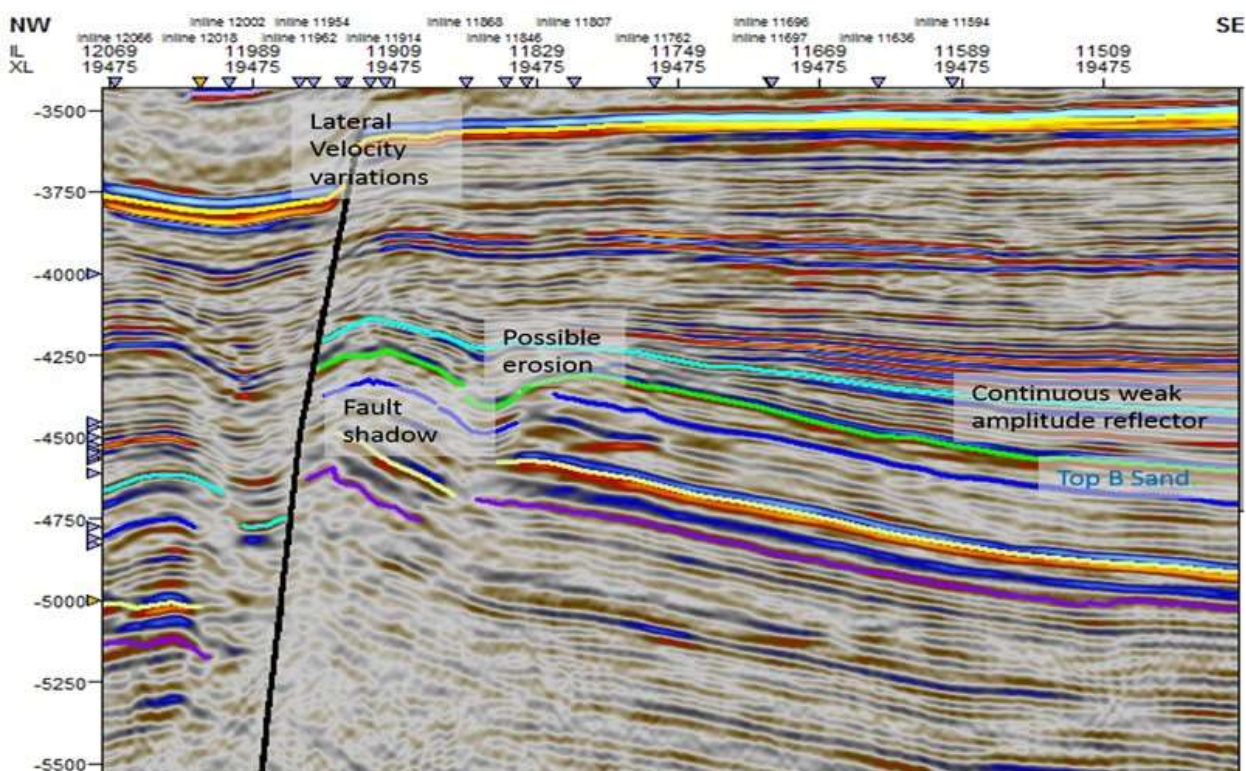


Figure 2-15 Cross-line 19475.

Figure Note: The Top B sand (dark blue).

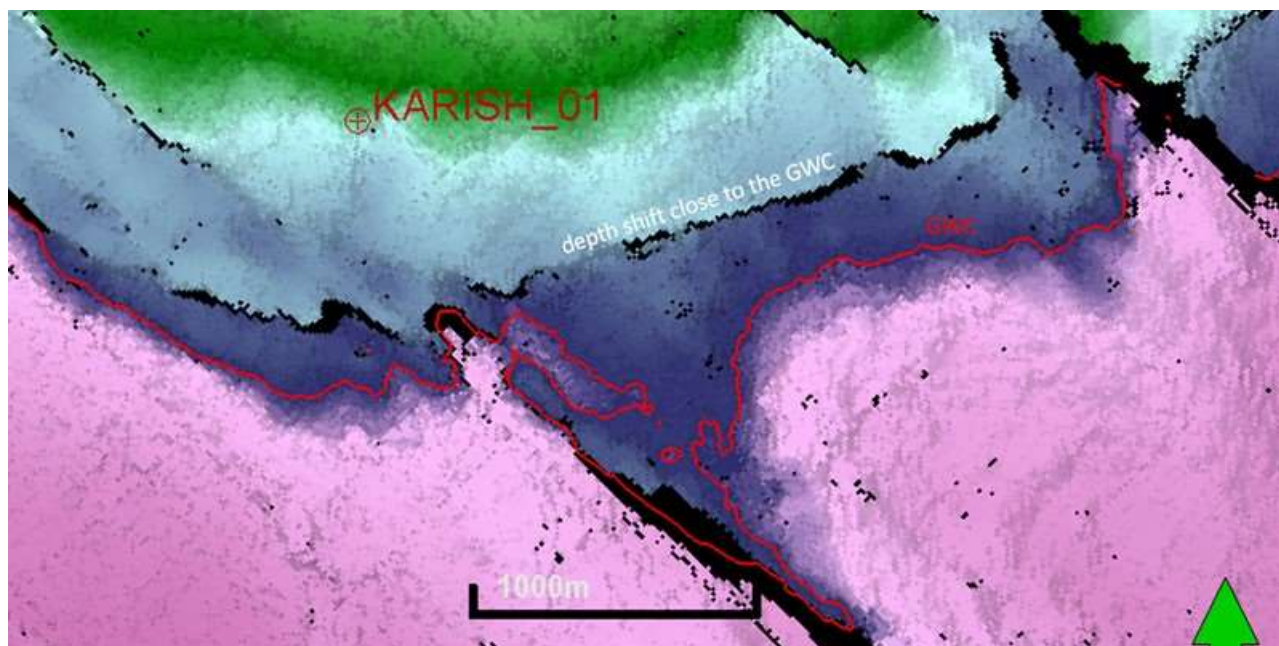


Figure 2-16 Depth shift due to tuning.

Figure Note: Tuning of the Top C Sand reflector and the GWC reflector (flat spot)

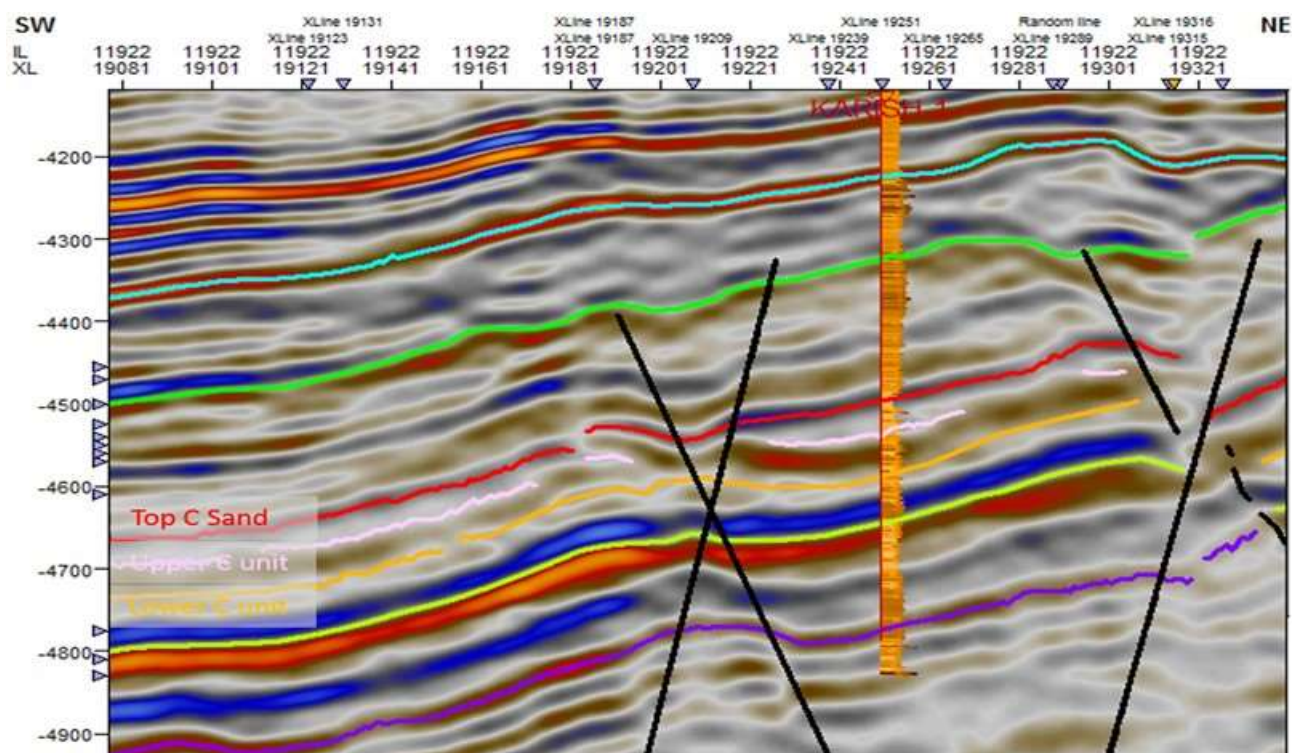


Figure 2-17 Inline 11922.

Figure Note: The upper C thick sand unit is separated from the lower interbedded sand unit by the pink horizon

Two internal C Sand reflectors were interpreted in order to investigate and extract potential facies information for the static model. Figure 2-17 shows the two internal C sand horizons interpreted.

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The upper C sand unit is almost entirely sandstone with a NTG of 93%. The resolution of the seismic is not adequate to resolve the upper C sand unit thickness over the entire Karish field complex. The upper C Sand unit was interpreted where it could be resolved. The extent of the interpreted upper C Sand unit is shown in Figure 2-24. Although the Upper C Sand is present over the wider area including the Karish lease the thickest part of the upper C Sand is better developed to the SW side of the Karish lease.

The underlying lower C sand unit is thinly layered and shows minimal thickness variations over the Karish field complex.

The Top D Sand was interpreted over the entire lease. The quality of the interpreted horizon is excellent. The Top D Sand interpretation (Figure 2-22) was robust in the low seismic quality areas as described above. Subsequently the Top D Sand trends were used to guide the interpretation of shallower horizons The Top 3.5D Sand was also interpreted.

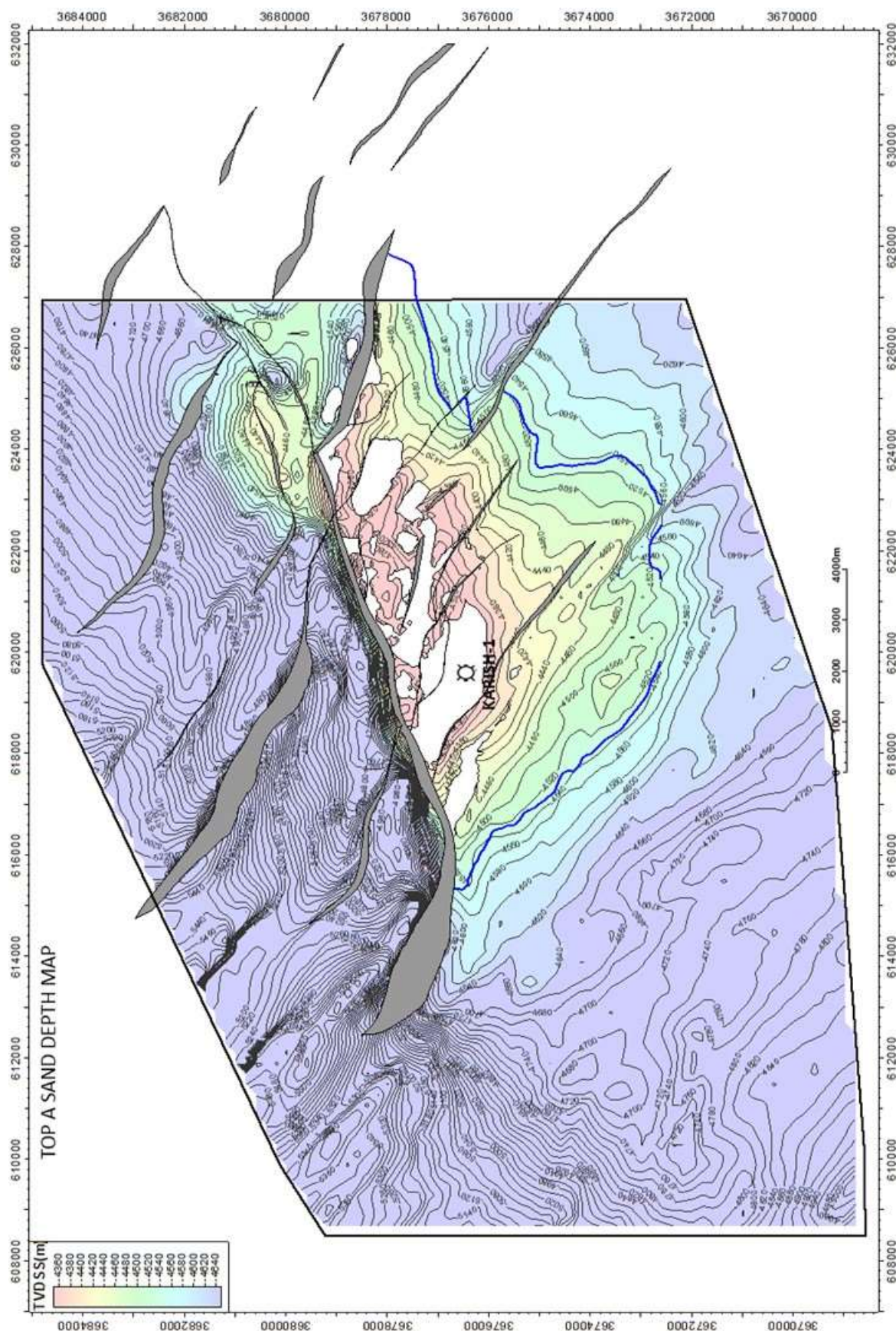


Figure 2-18 Top A Sand structural depth map (m)

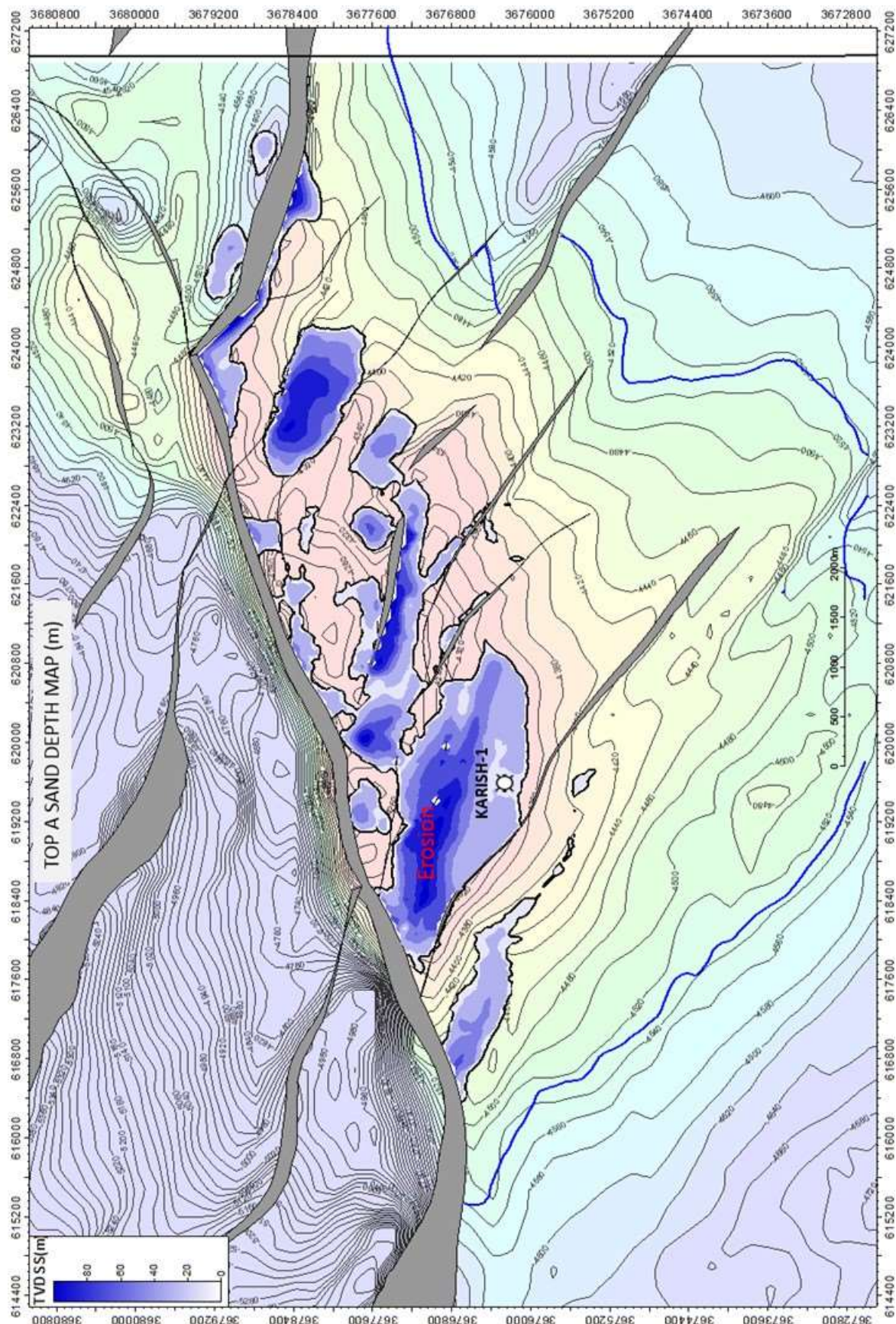
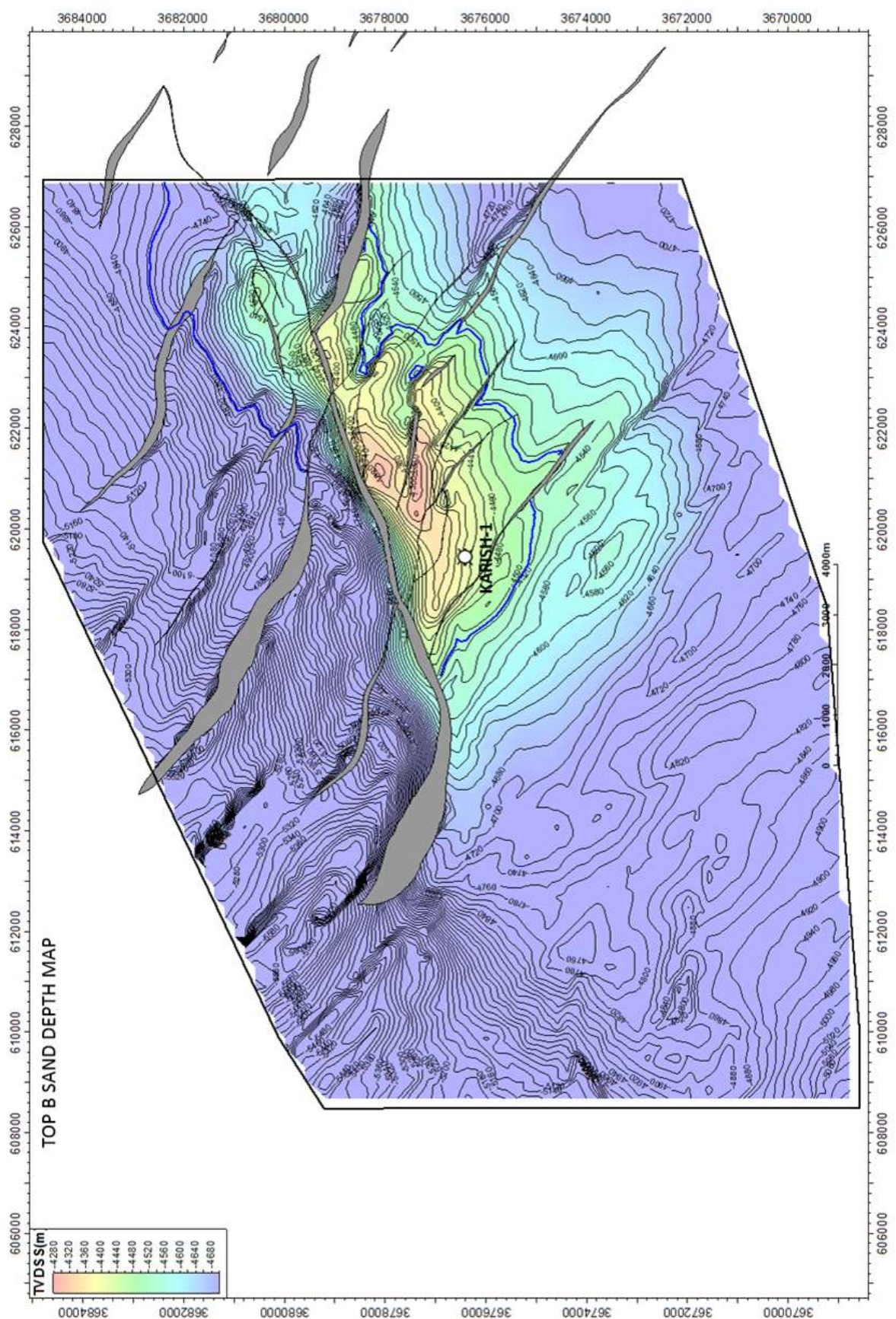


Figure 2-19 Top A Sand structural depth map (m) showing also the eroded areas



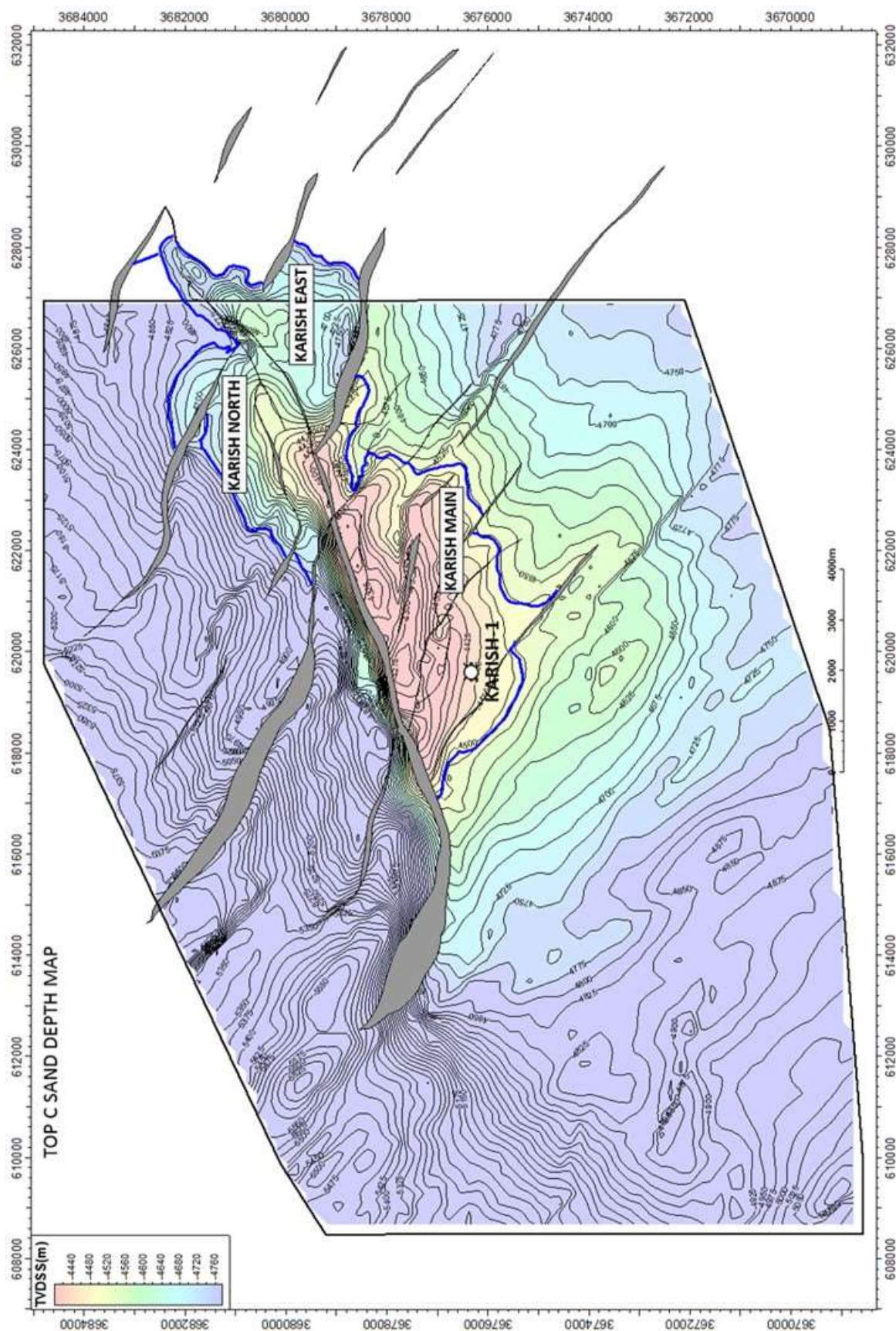


Figure 2-21 Top C Sand structural depth map (m)

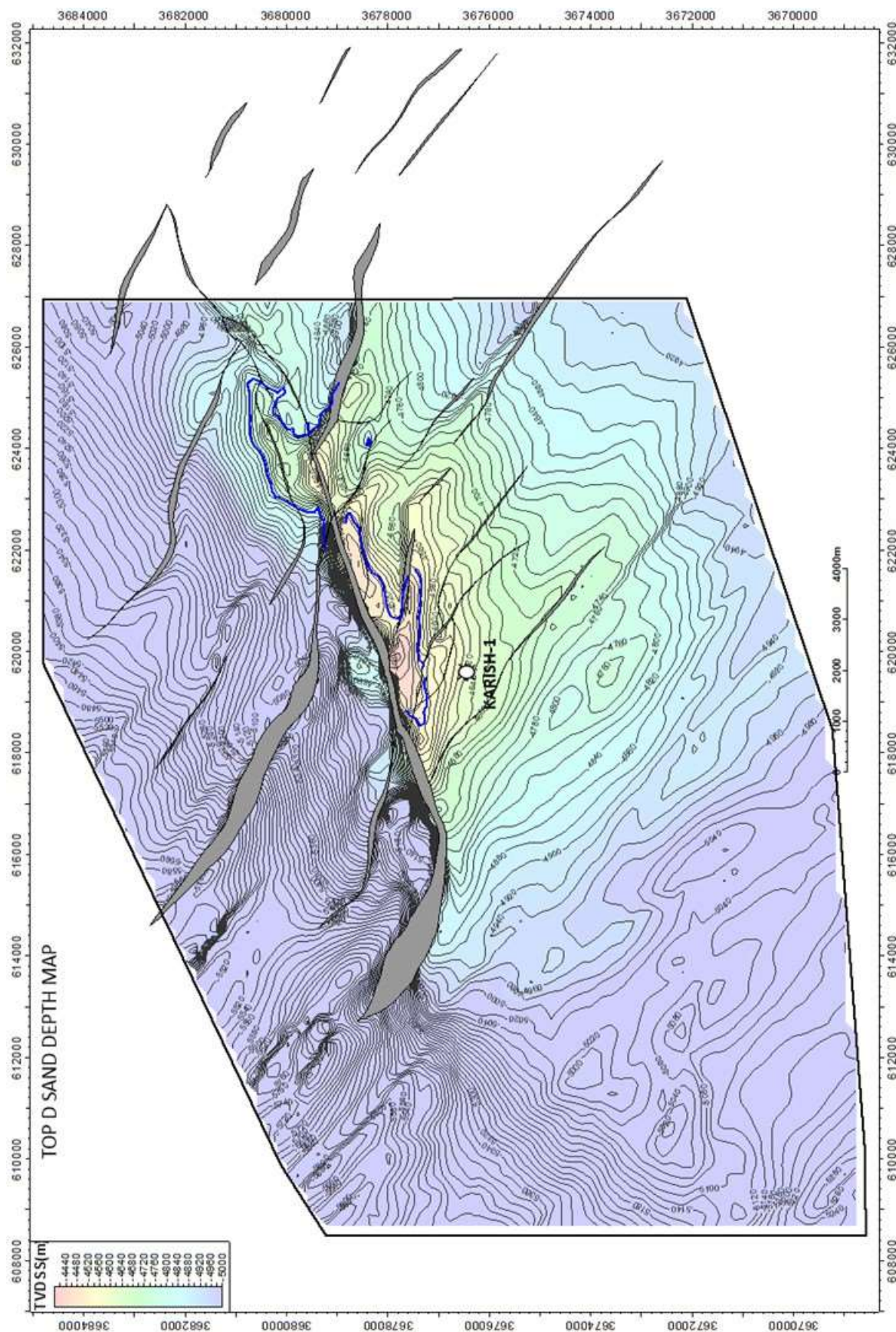


Figure 2-22 Top D Sand structural depth map (m)

2.5.4.2 Tectonostratigraphic Evolution of the Karish Field Complex

The Levantine Basin formed due to pulsed breakup of Gondwana during the Palaeozoic to Mesozoic (Gaffunkel, 1984). The strongest rifting pulse is believed to have occurred during the Early to Middle Jurassic. The extension occurred in the NW-SE direction with the major fault block orientation NE-SW. The north bounding fault to the Karish field is oriented ENE-WSW ("main fault") and originated during the rifting phase Figure 2-23.

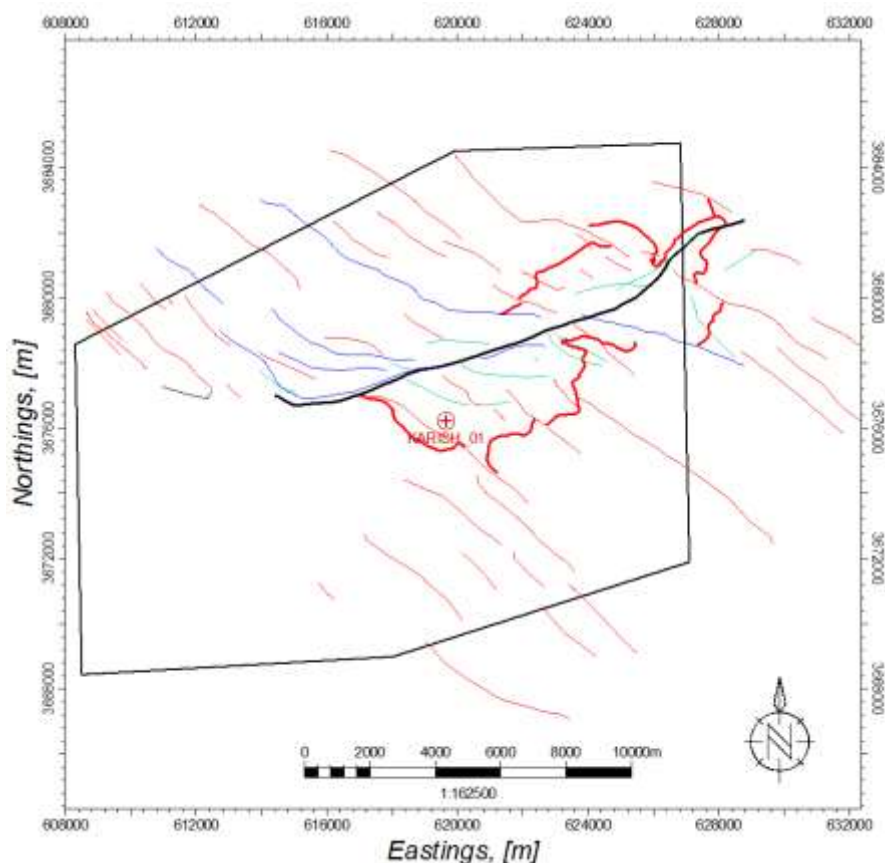


Figure 2-23 Fault Interpretation, Karish lease

Figure Note: Black: ENE-WSW Jurassic faults. Red: NW-SE Oligo-Miocene faults. Blue: Hard linked of Oligo-Miocene and Early Miocene low angle faults. Green: WNW-ESE Early Miocene faults

The basin was in a passive continental margin setting until the Late Cretaceous where the region starts to experience compression until the Paleogene due to the convergence of the African and Eurasian plates. This led to the inversion of older structures including the Karish structure. The Cretaceous sedimentary interval pinches out to the west of the Karish lease. The deeper Jurassic structure is consistently on-lapped until the Eocene.

A major regional unconformity in the Late Eocene is composed of deep marine chinks, shales and marls. According to Kosi (2012) this stratigraphic interval is acting as the basal detachment surface for the heavily faulted, overlying Oligocene to Miocene sequence.

The Oligocene to Miocene sequence is dominated by the clastic influx due to the onset of regional doming and uplift of East Africa (Afar plume and Red Sea rift). Therefore large amounts of terrigenous material supplied from Africa resulted in a much wider fluvial system and in shelf propagation that pushed the coastline of North

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Africa hundreds of kilometres northward resulting in wide spread basin floor fans that reached the Tanin-Karish area proved by the corresponding exploration wells in each Lease.

The Oligocene to Miocene normal faults trend NW-SE (Figure 2-23) and are spaced approximately 3-4km apart and measure throws up to 400m. The origin of the extensional tectonic event is not fully understood, it appears to be active during a break in compression and between the Syrian Arc I and II tectonic phases.

Isopachs of the successive reservoir units are used to explain the depositional model in the Karish area.

Figure 2-25 shows the isopach between the Top D and Top 3.5D surface. The isopach represents the deeper unit of the Tamar Sands. The thickness of the unit is uniform apart from the area north of the “main fault” where it is slightly thinner, indicating that that the fault was active. The WNW-ESE low angle faults (Figure 2-23) associated with the “main” fault are also active. These faults link up with the pre-existing NW-SE normal faults. The overlapping fault segments define relay ramps. These soft-linkage elements eventually break down by breaching creating hard fault linkages as growth continues. An extensive fault/seal analysis study was undertaken to investigate the linkages of all the faults in the Karish and Tanin areas.

The Late Miocene tectonic compressional event appears to have re-activated the older ENE-WSW Jurassic fault that today forms the north-bounding fault to the Karish Field structure (The footwall to the north is downthrown today 400m). The orientation of the compression caused by dextral strike-slip movements coupled with the orientation of the “main fault” cause a restraining bend system that eventually results in the uplift and creation of the Karish structure.

Figure 2-26 shows the isopach between the Top C and Top D surfaces. The C Sand is thicker in the SW. Dextral strike slip movement culminates in a basin floor topographic high to the east of the Karish lease. Sediment supply from the west ponded against the high restricting the basin floor fans to the Karish area. The upper C sand unit was described in section 2.5.4.1 and is shown on Figure 2-24.

Figure 2-27 shows the isopach between the Top B and Top C surfaces. It is evident from the Isopach that further compression shifted the apex of the Karish structure further to the west resulting in a thinner B Sand unit over the crest of the Karish structure. A thicker B Sand unit is expected over the Karish East and Karish North areas.

The isopach of the Top A unconformity and the Top B (Figure 2-28) indicates further uplift of the Karish structure that eventually results in the submarine erosion of the A Sand at the crest. The erosional features are oriented along the strike of the WNW-ESE low angle faults. Erosive channels are also visible on the isopach.

Figure 2-29 shows an isopach of the Top A unconformity and the Mid Miocene Unconformity which drapes over the Karish structure. South of the “main” fault there is an increase in thickness along the hanging wall of the low angle faults. The thickness of fill against each low angle fault diminishes towards the east. Therefore the underlying A sand is more likely to be preserved towards the Karish North and Karish East area.

The area north of the main fault shows a rapid increase in thickness. This is due to the pull apart extension associated with the dextral strike-slip movement.

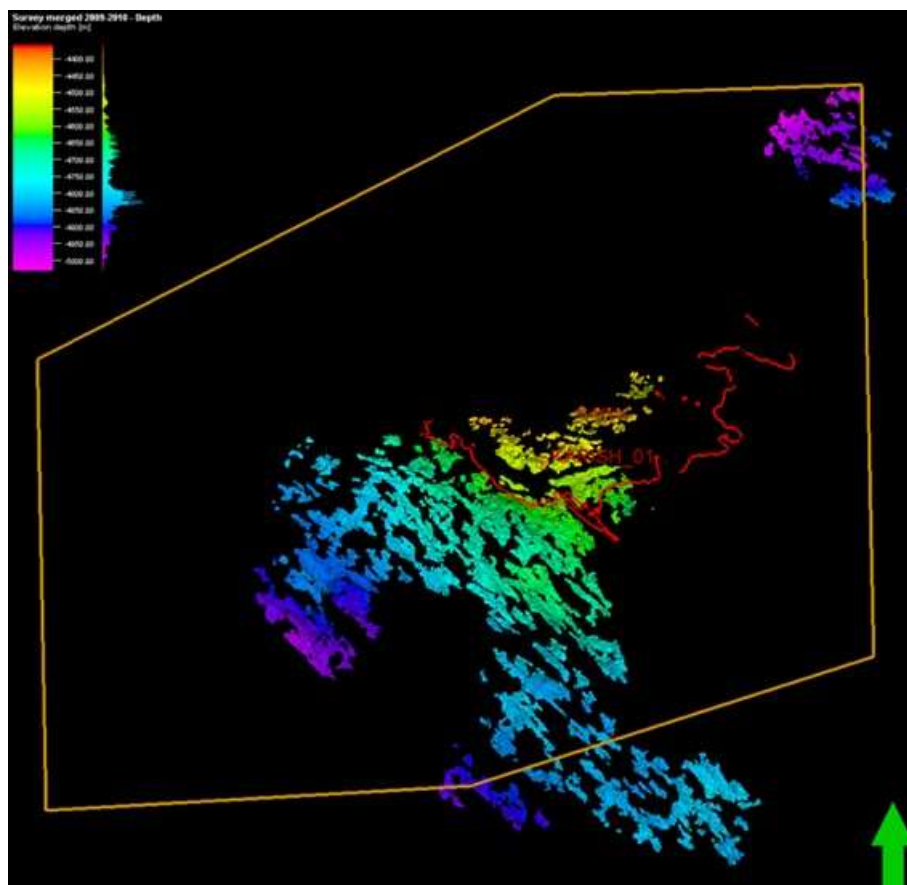


Figure 2-24 The interpreted thick upper C sand

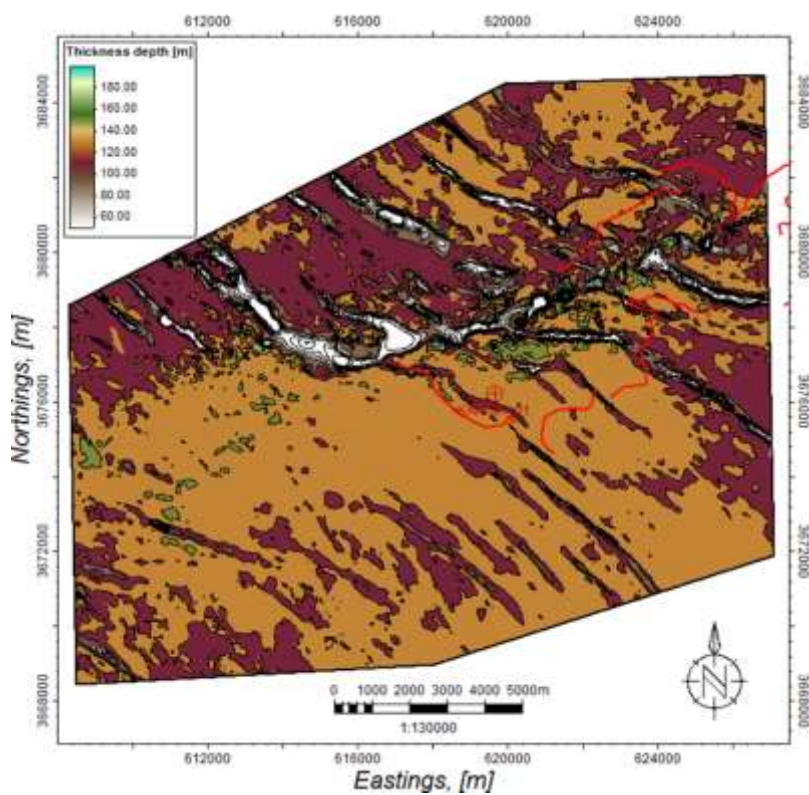


Figure 2-25 Isopach of the Top D and Top 3.5D sands

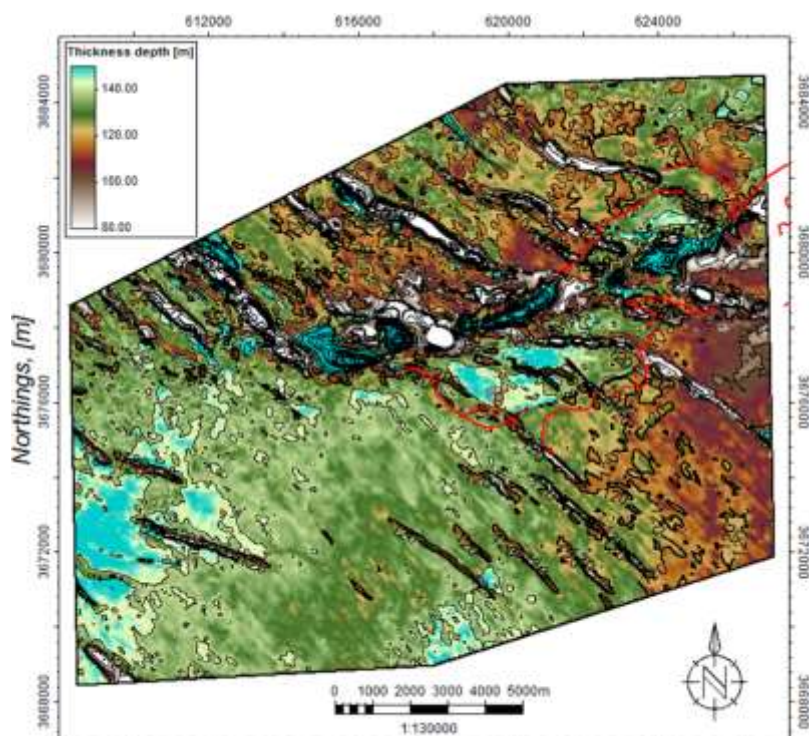


Figure 2-26 Isopach of the Top C and Top D sands

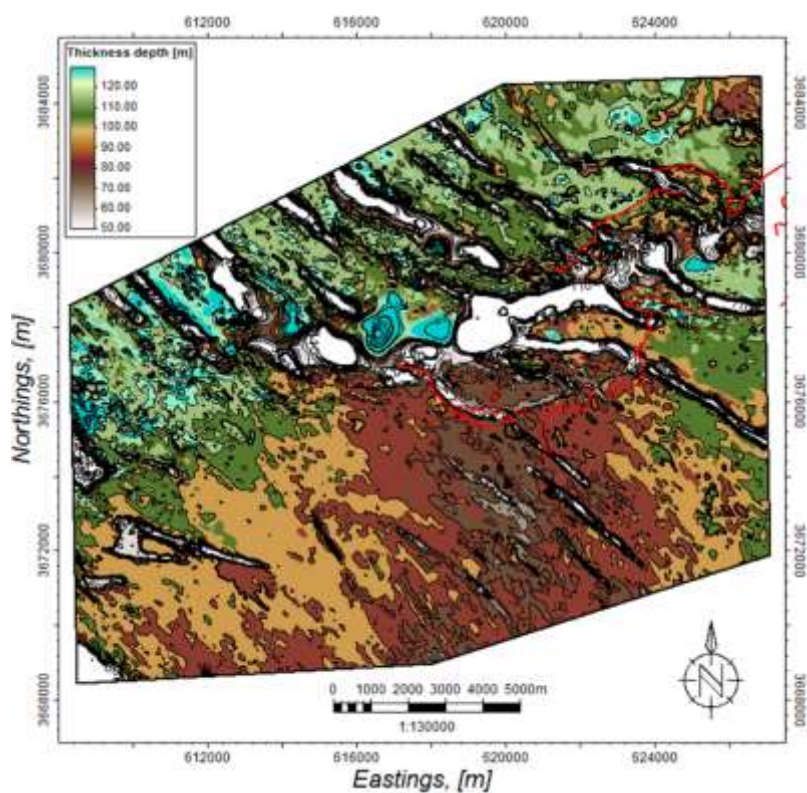


Figure 2-27 Isopach of the Top B and Top C sands

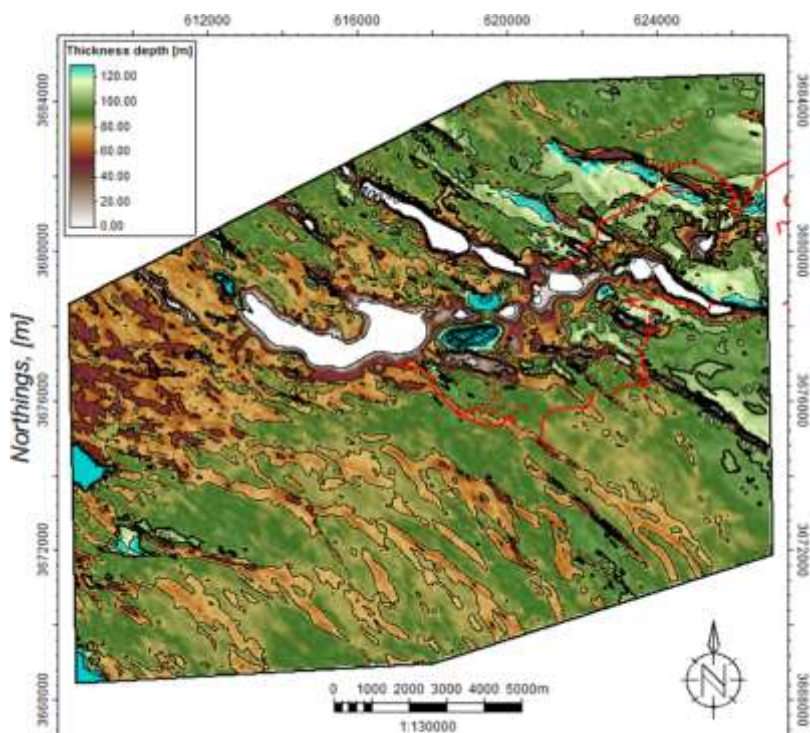


Figure 2-28 Isopach of the Top A and Top B sands

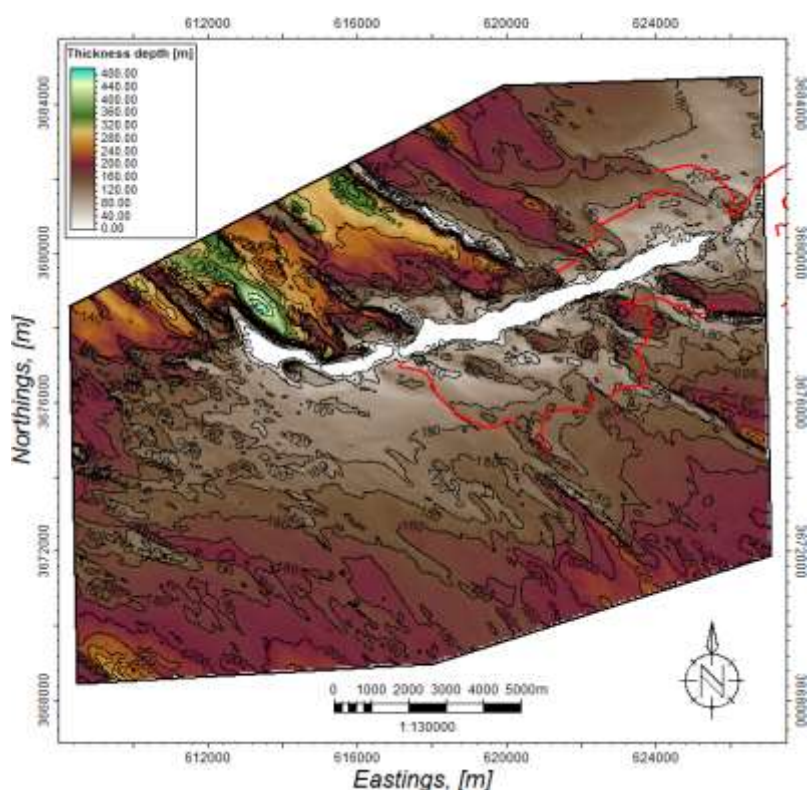


Figure 2-29 Isopach of the MMU and Top A unconformity

2.5.4.3 Karish Complex and Direct Hydrocarbon Indicators

The Karish Field Complex encompasses three main closures. The Karish Main segment is described as a two way closure against two faults. Bound to the North by the reactivated Jurassic main fault and to the east of the field by an Oligo-Miocene normal fault. The extent of the Karish Main segment is based on the structurally consistent flat spot that matched the GWC observed in the Karish-1 well (Figure 2-32).

Evidence of direct hydrocarbon indicators over the Karish Field Complex due to gas are listed below:

Horizon interpretation of the C Sand identified a depth shift close to the GWC. This is due to tuning between the Top C Sand reflector and the reflector associated with the gas-water contact, flat spot (Figure 2-16). The depth static was also observed on the forward model response shown on Figure 2-30 A and B. The depth shift occurs prior to the actual pinch-out of the GWC with the top sand. The effect was observed on Figure 2-16. The angle of top sand in relation to the contact determines the offset discrepancy between the “depth shift” on the horizon and the actual GWC (Figure 2-16).

- Figure 2-32 shows the extent of the “Bright spot”. The top sand amplitude above the GWC is stronger than the amplitude observed below the GWC (Figure 2-30-C). The forward model indicated a similar bright spot response Figure 2-30-B.
- Finally the flat spot appears to sag over the larger gas column at the crest of the structure.
- The lower frequency content of the seismic below the Karish Field is due to the loss of high frequencies as energy passed through gas interval

The elastic model used to generate the forward modelled response was built using Vp, Vs and density from well logs.

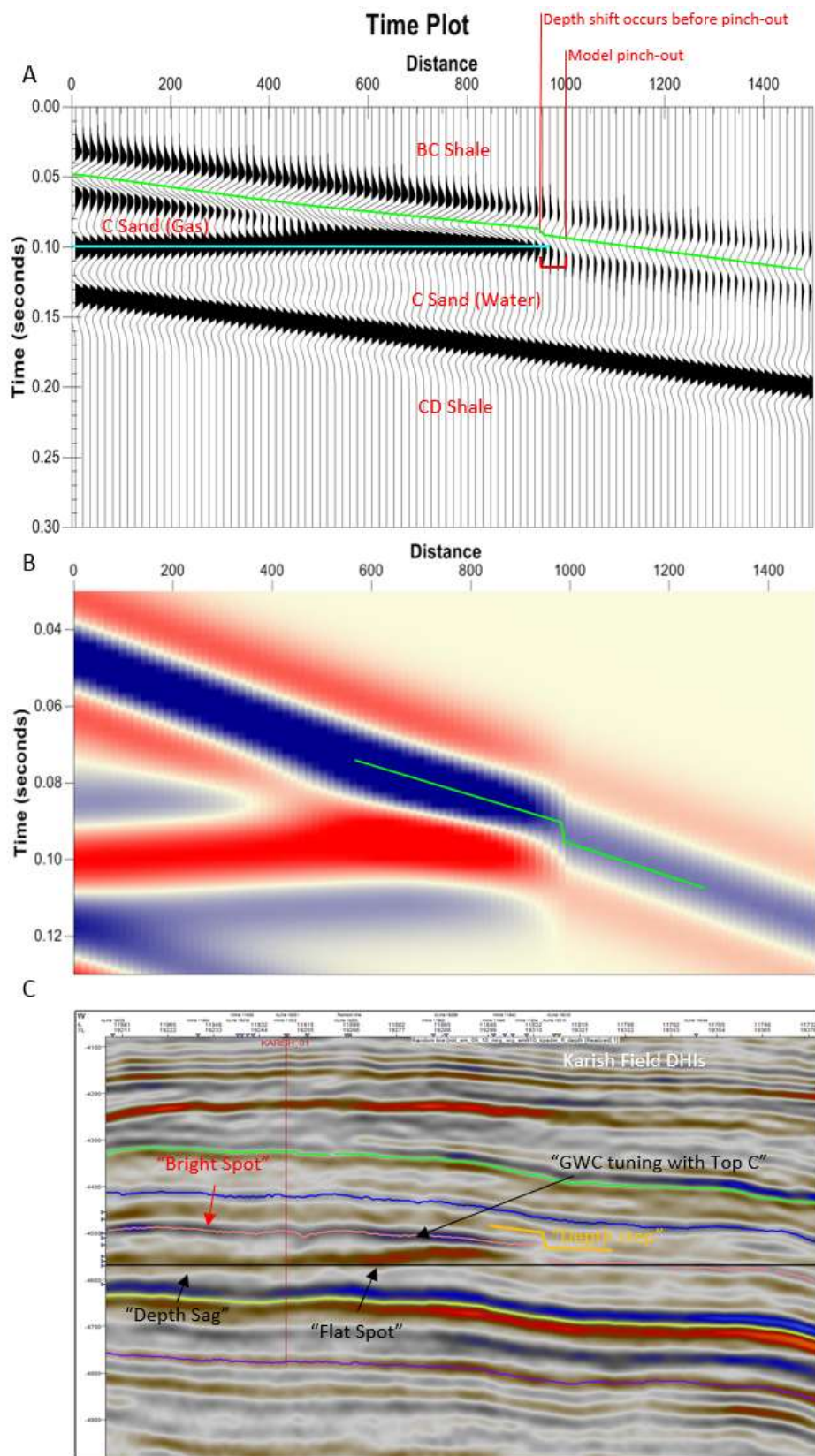


Figure 2-30 Modelling of Karish flat spot.

Figure Notes: A: Forward modelled pinch-out of the GWC to the Top C Sand. B: Modelled depth shift. C: Seismic section showing the bright spot, flat spot, depth static and depth static. All observed DHIs match with the forward modelled response.

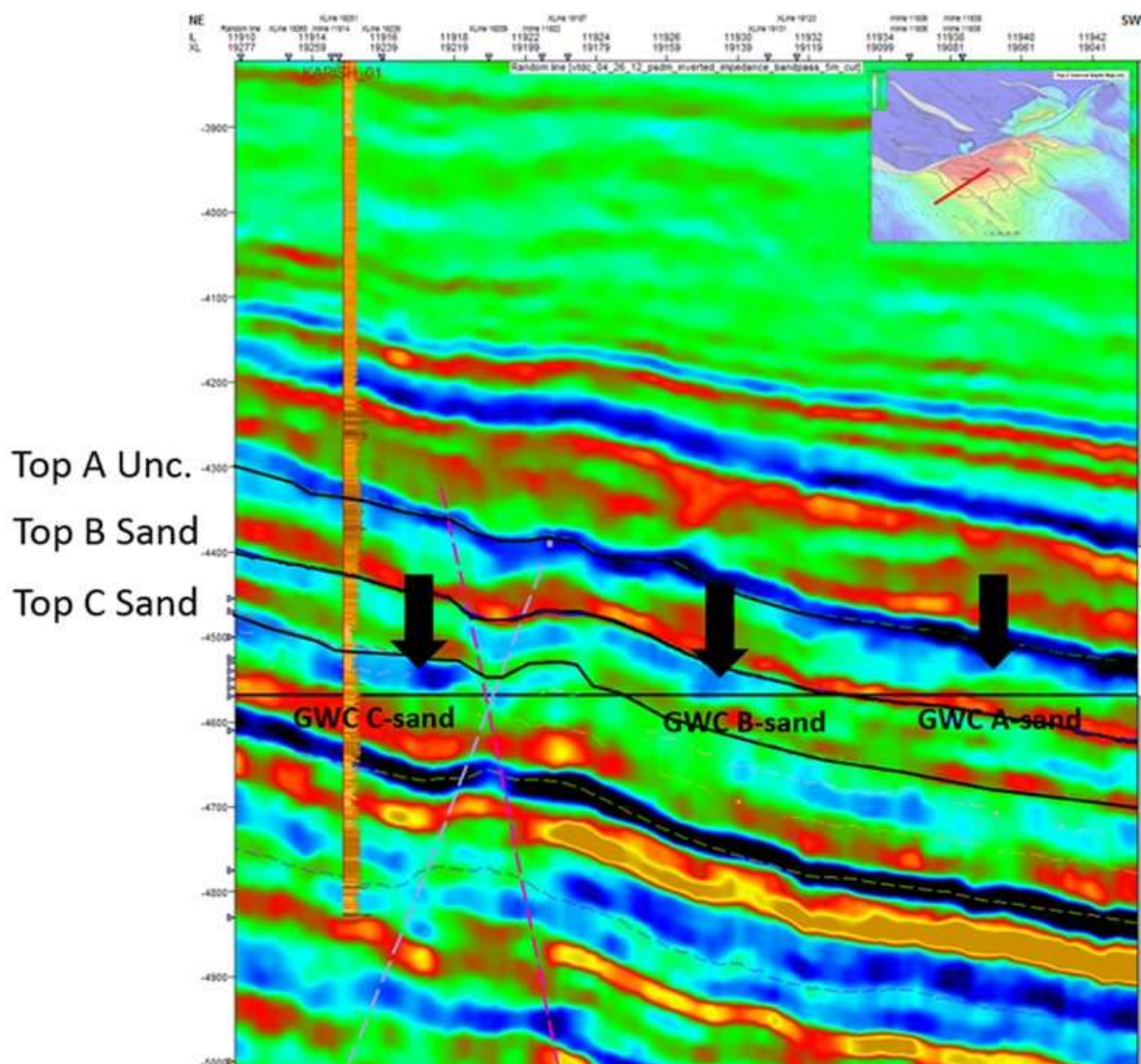


Figure 2-31 Acoustic Impedance section showing a common GWC..

Figure Note: Acoustic Impedance line. The arrows indicate the change in acoustic impedance across the GWC for all sand units. Blue is low impedance (gas sand).crossing into the green higher impedances below the GWC. A flat spot is observed in each sand unit.

Figure 2-31 shows an inverted acoustic impedance seismic line. The arrows indicate the change in acoustic impedance across the GWC. Blue is low impedance (gas sand). Below the GWC all the sand units become green to red reflecting the higher acoustic impedance (water saturated sand). A flat spot is observed in each sand unit. The A, B and C sands appear to have a common contact. The D sand is found above the GWC close to the E-W fault and therefore is affected by poor seismic quality. However fault seal analysis has shown that the C and D sands are entirely juxtaposed against each other along internal faults in the Karish Main field.

Karish North was originally thought to be a three way closure bound to the south by the “main” Jurassic fault. It appears that the Karish North structure connects to a smaller structure to the NE that has the same GWC as deduced from seismic flat spot.

The Karish North DHI is deeper than the GWC observed in the Karish main structure.

Karish East is a structure separated from the Karish Main structure by a NW-SE Oligo-Miocene normal fault with a throw in excess of 200m. The Karish East structure appears to be at the same depth level as the Karish North structure. It is believed that the Karish North and Karish East structures could form a single four-way closure. Figure 2-33 shows three successive seismic crosslines that illustrate the juxtaposition of the Karish East and Karish North structures at the C Sand level.

Figure 2-33-A shows the most northern crossline. The Karish East block is downthrown compared to the Karish North fault block. Figure 2-33-B is the middle crossline and shows a good juxtaposition of the C sand across both fault blocks. Finally Figure 2-33-C shows the most southern crossline. The Karish North fault block is downthrown in relation to the Karish East fault block. The switch in throw over the length of the “main” fault is due to the dextral strike slip movements. Importantly Figure 2-33 shows that there is a region between the Karish North and Karish East fault blocks that are in perfect juxtaposition.

The DHI observed over the Karish North fault block is not visible on the Karish East structure (Figure 2-33). The seismic quality is poor over the Karish East area and possibly masks the effect of the DHI. It should be noted that the estimated depth of the DHI observed at Karish north corresponds to the structural spill point of the Karish East structure.

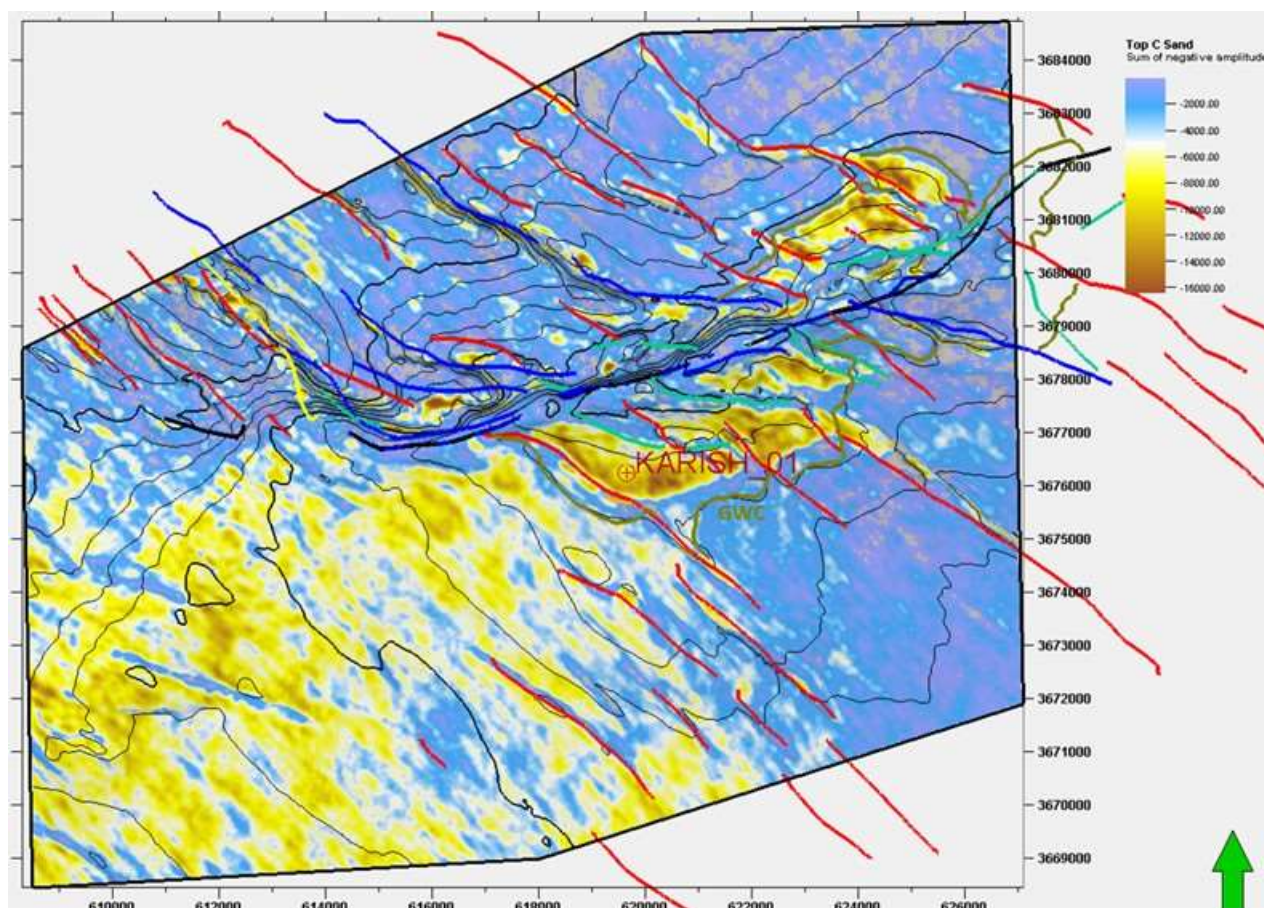


Figure 2-32 Top C sand surface attribute “bright spot”.

Figure Note: (Seismic attribute: sum of negative amplitudes)

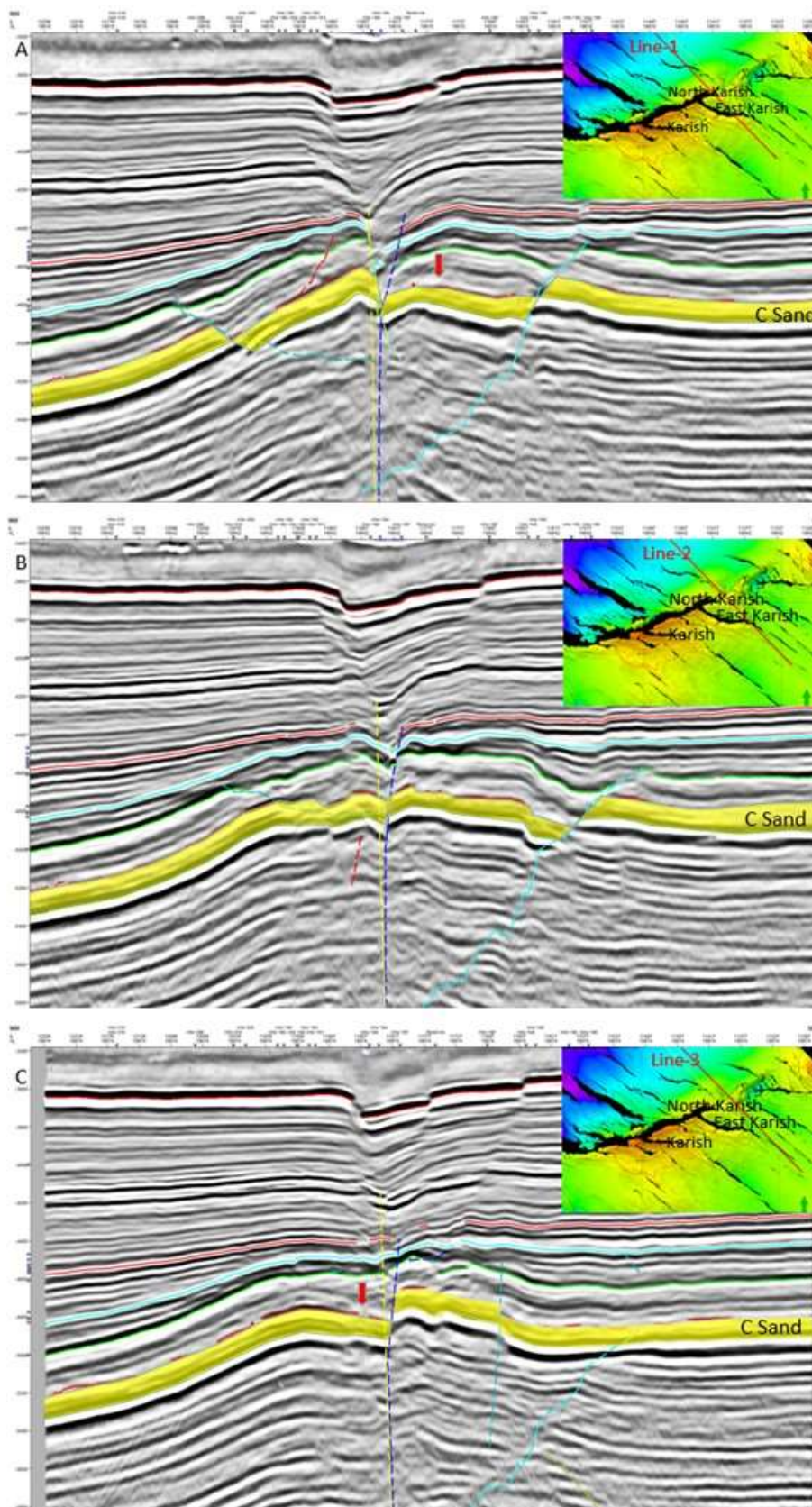


Figure 2-33 Juxtaposition of Karish North and Karish East.

Figure Notes: A: The southern seismic line (Line-1) shows the East Karish block is downthrown. B: Middle seismic line (Line-2) shows good juxtaposition between both blocks. C: The northern seismic line (Line-3) shows the Karish North block downthrown compared to Karish East.

2.5.5 Tanin Lease Interpretation

2.5.5.1 Horizon Interpretation

The Kirchhoff Pre-SDM 3D seismic volume was used for the interpretation of the Tanin lease. Figure 2-34 shows the seismic correlation of the Karish-1 and Tanin-1 wells. The correlation is excellent. The amplitude variations of corresponding intervals reflect the differences in sand content as seen on the GR.

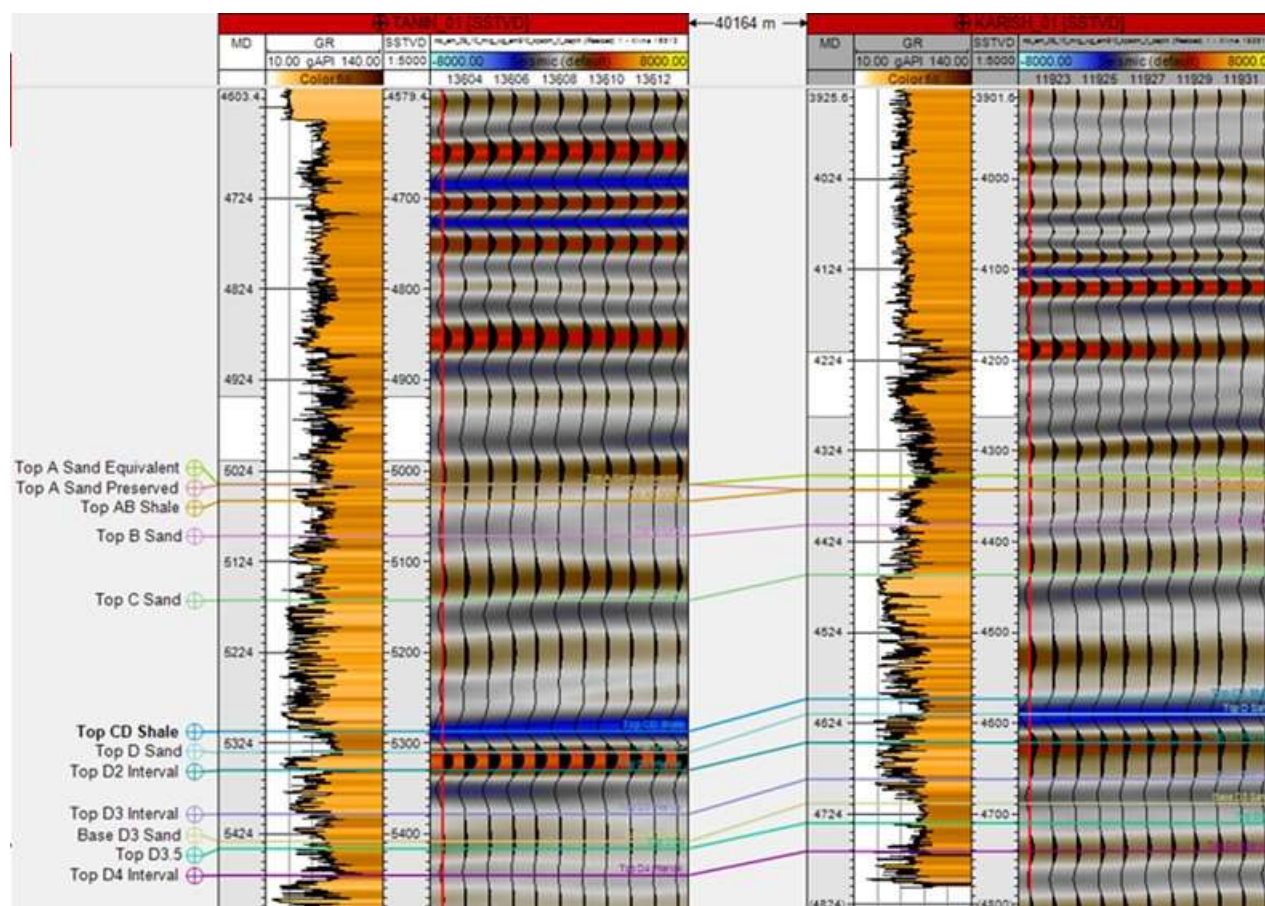


Figure 2-34 Seismic correlation of the Karish-1 and Tanin-1 well

The A Sand is fully developed in the Tanin-1 well. The Top A unconformity does erode the A sand over the highs in the vicinity of the Tanin field complex, the fault shoulders of the footwalls being the most similar areas (Figure 2-35).

The Top A unconformity is an excellent reflector interpreted over the entire Tanin lease.

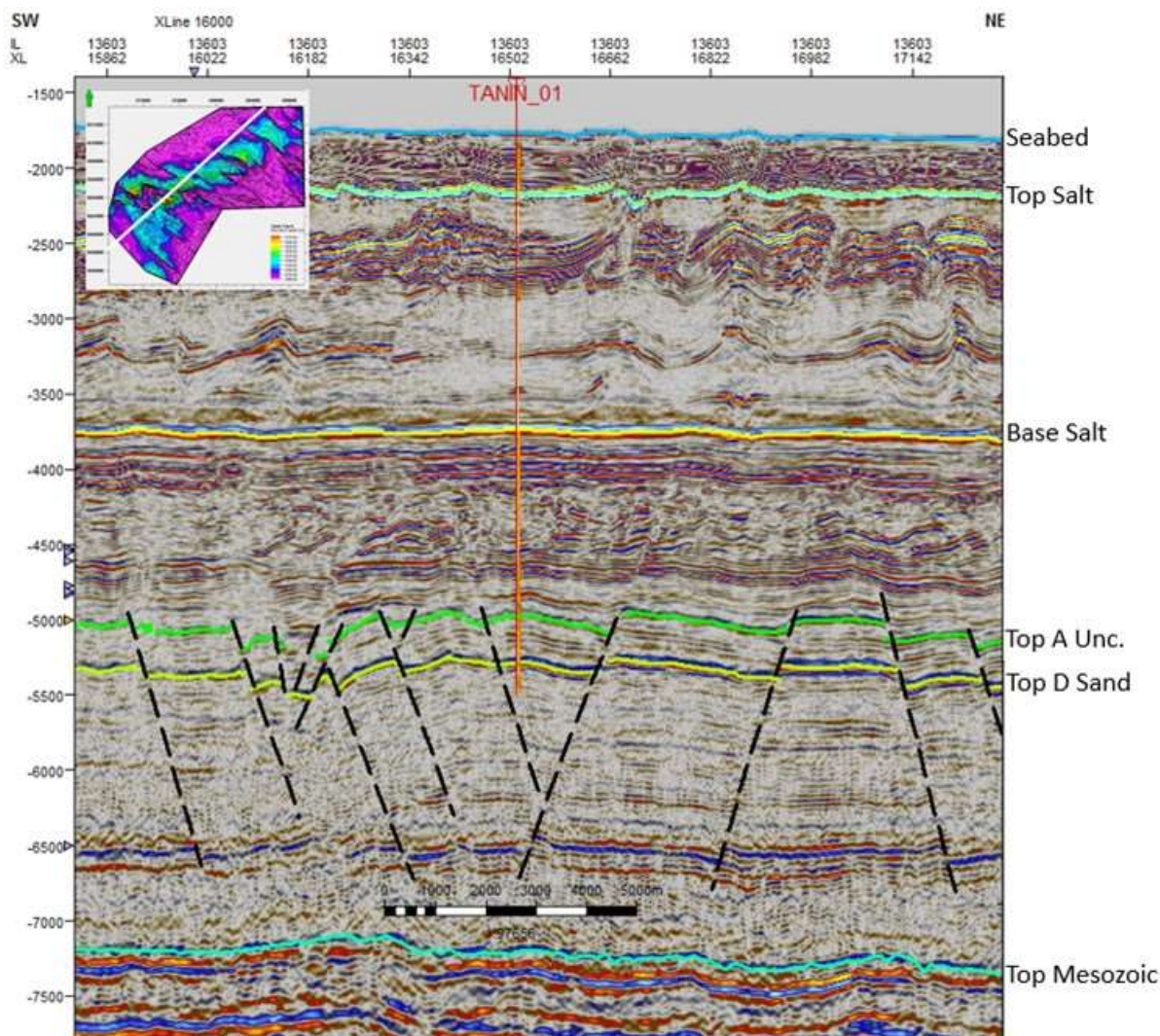


Figure 2-35 Inline 13603 across the Tanin-1 well.

The Top D Sand was also interpreted over the entire Tanin Lease area. Similarly to the Karish area the Top D surface trends were used to guide the interpretation of other horizons in poor seismic quality areas.

2.5.5.2 Tectonostratigraphic Evolution of the Tanin Field Complex

The Tanin area is 20km east of the Karish lease and has a similar geological history to the Karish area as described in section 2.5.4.1.

Similarly to the Karish area, the Jurassic faults observed in the Tanin area are oriented ESE-WNW. During the passive margin phase a thick package of the Cretaceous sediments on-lapped the Jurassic high as seen on Figure 2-36.

A major regional unconformity in the Late Eocene is composed of deep marine chinks, shales and marls. According to Kosi (2012) this stratigraphic level is acting as the basal detachment surface for the heavily faulted overlying Oligocene to Miocene sequence.

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During the Oligo-Miocene times large amounts of terrigenous material were deposited in the Levantine basin through an extensive fluvial system (Nile River to the east) extending to a widespread basin floor fan system. NW-SE oriented normal faults were active during the same period (discussed in section 2.5.4.1).

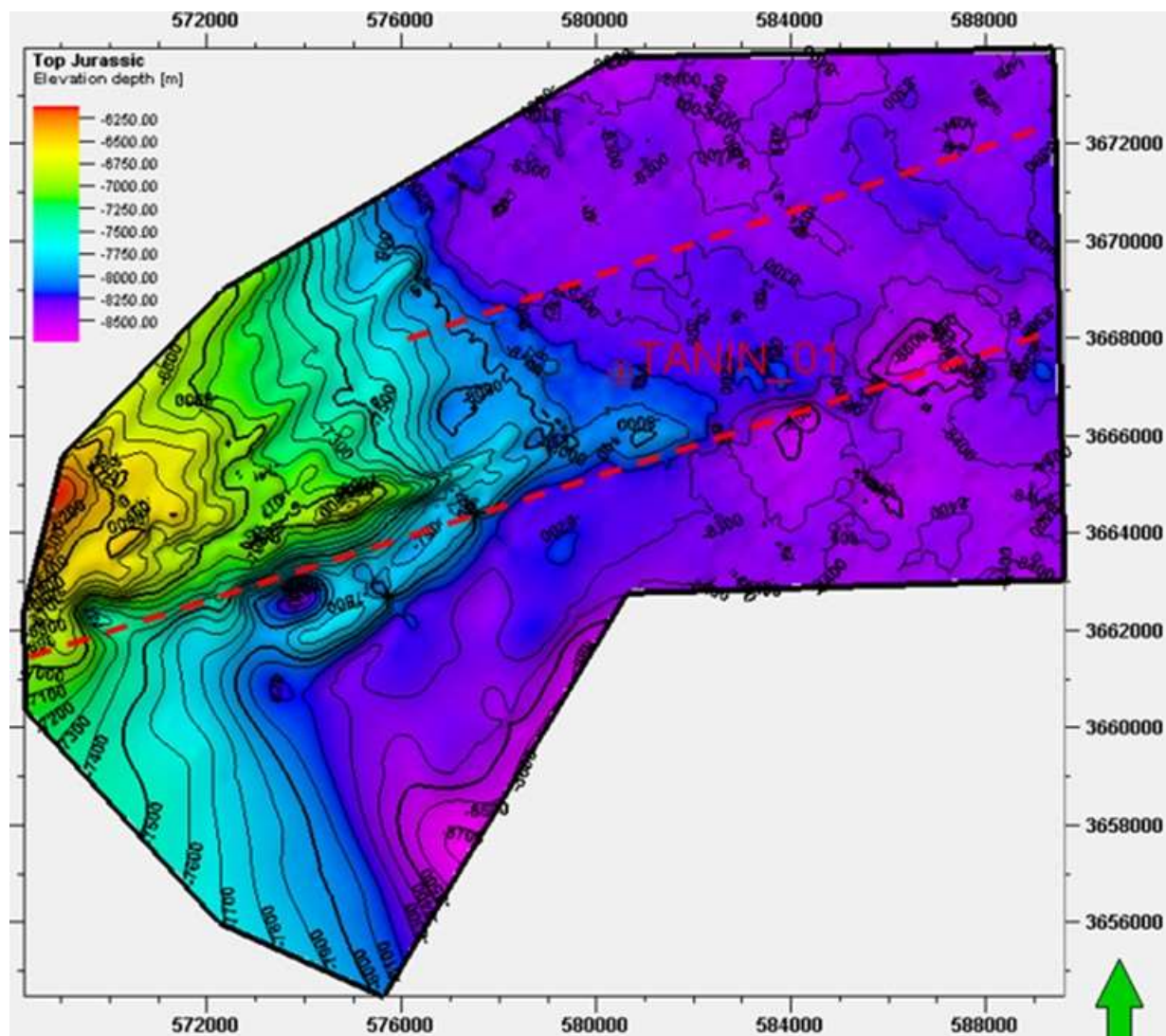


Figure 2-36 Top Jurassic. The ESE-WNW Jurassic faults in red

Syrian Arc II compression during the Late Miocene re-activated the older Jurassic ESE-WNW faults into dextral strike-slip faults. NE trending anticlines folded the fault blocks oriented NW-SE. The uplifted echelon structures include the Tanin A, B C, D, E and F blocks (Figure 2-37).

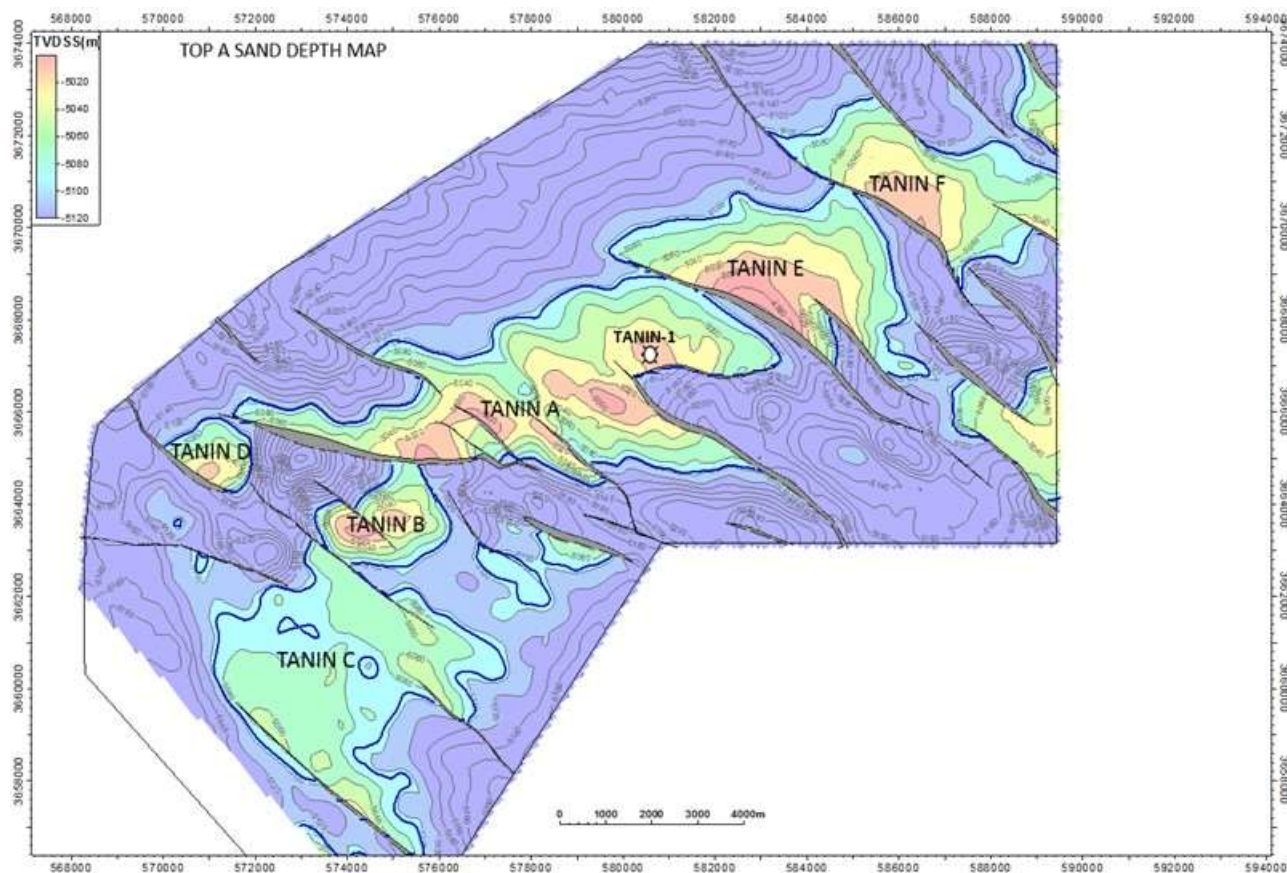


Figure 2-37 Top A Sand Tanin Field Complex. NW trending echelon structures

2.5.5.3 Tanin Field Complex

The Tanin Field Complex includes six main structures (Figure 2-37). The Tanin A, B and C segments have a common GWC. The Tanin D, E and F structures appear isolated. Regionally the Tanin structure is a WNW-ESE anticlinorium that is segmented by NE-SW Oligo-Miocene normal faults and E-W faults associated with the dextral strike-slip movements of the older Jurassic faults.

Figure 2-38 shows a seismic line oriented NW-SE and along the fold axis of the regional anticlinorium. The same figure shows a characteristic seismic crossline over the Tanin E structure. Three way closure structure bound to the west by an Oligo-Miocene normal fault.

Figure 2-39 shows an arbitrary seismic line over the Tanin-1 well. It is clear that the amplitude of the Top A Sand reflector diminishes as the reflector rises above the GWC. East of the fault the Top A Sand reflector is faulted down below the GWC consequently the amplitudes become higher. The dimming of the Top A Sand over the highs is structurally consistent over the entire Tanin lease. A maximum amplitude surface attribute over the Top A Sand (Figure 2-40) shows that the "dark blue" low amplitude areas correspond to the GWC polygon (red) determined from the CPI of the Tanin well.

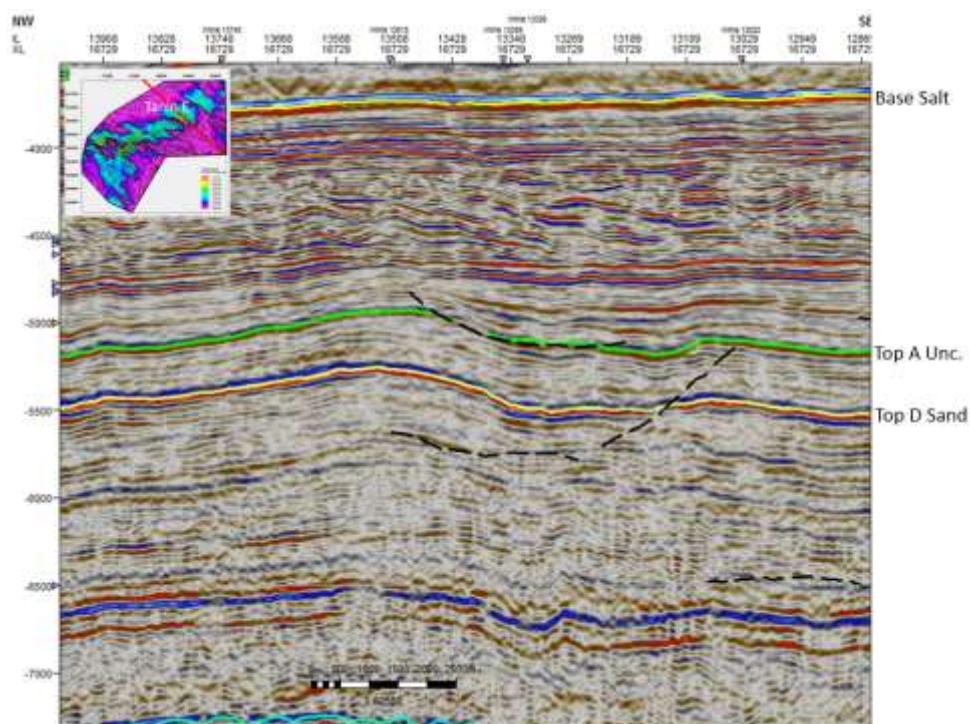


Figure 2-38 Seismic line over Tanin Block E.

Figure Notes: Cross 16729. Oriented NE-SW located over the Tanin E structure. The anticlinorium results from the Late Miocene compression event. Characteristic line of all the Tanin structures.

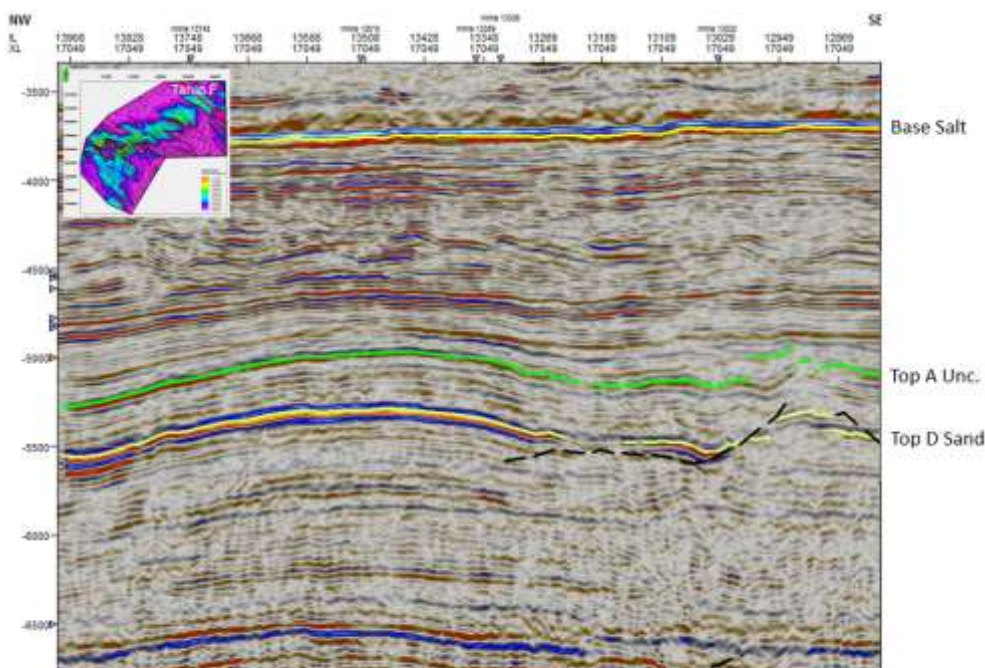


Figure 2-39 Arbitrary line through Tanin-1.

Figure Note: Amplitude dimming above GWC

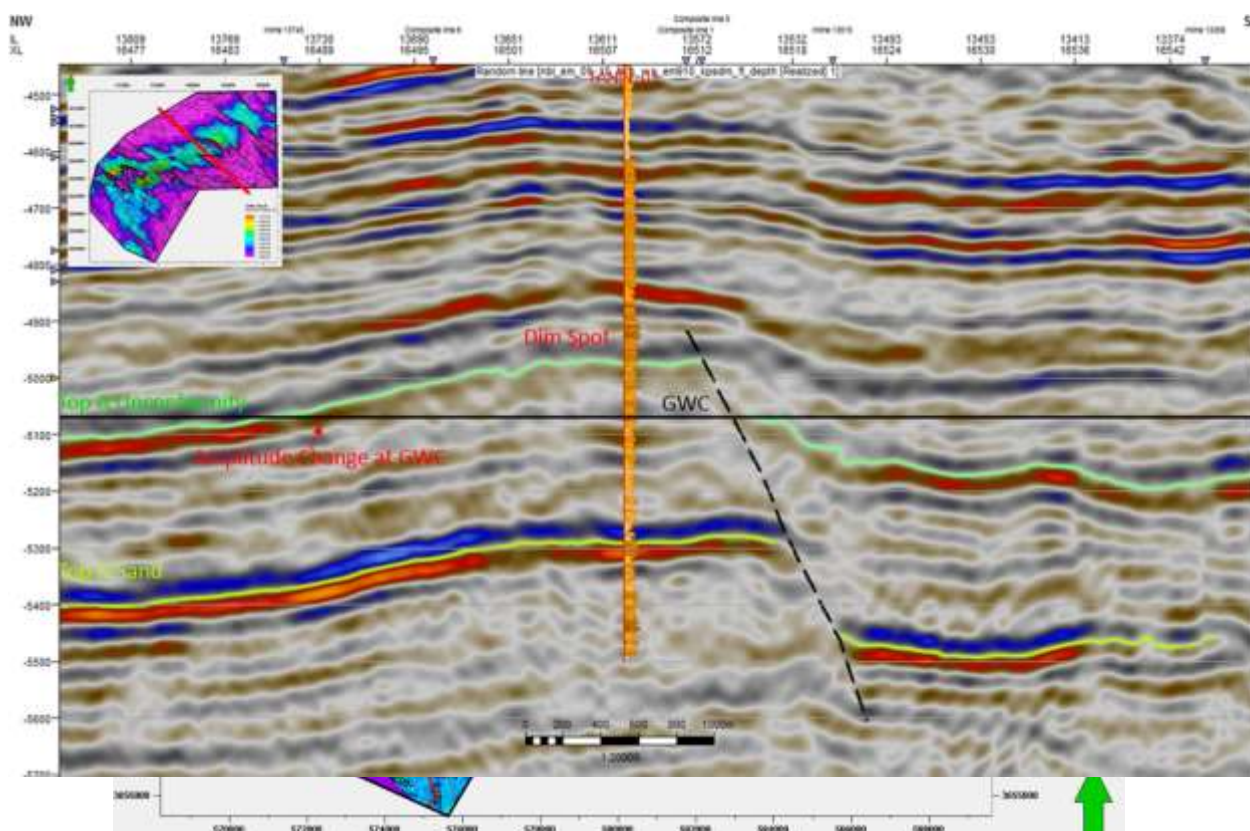


Figure 2-40 Top A Sand, Maximum Amplitude surface attribute

2.6 Section references

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3 Petrophysics

3.1 Summary

A full petrophysical interpretation of the Karish-1 and Tanin-1 wells was carried out in Q1 2017 by Down Under Geosolutions (DUG) on behalf of the Operator, in order to investigate the lithology, reservoir quality and fluid content of the submarine fan deposits of the Tamar Sands (Early Miocene). The workflow completed by DUG consisted of:

- Collation of relevant information.
- Input and merging of all available data.
- Quality check and curve editing including, but not restricted to, merging, depth matching and despiking
- Performance of environmental, “bad hole” and invasion corrections as required.
- Determination of a realistic interpretation model by utilising a variety of cross plotting techniques and researching the available data.
- Generation of synthetic curves (in particular shear velocity), where data are missing.
- Determination of lithology, porosity, fluid saturations and net/gross.
- Calibration of interpretation to any available core, NMR and/or test data.

3.2 Karish-1 Overview

Karish-1 is interpreted to contain a total of 63.3m net gas-bearing sandstones within the A, B and C Sand Units. The gas-water contact for Karish-1 is interpreted at 4535.2 mMDRT (4512m TVDSS) based on the pressure gradient plotted from the B and C Sand Units. All sands below 4535.2 mMDRT are essentially water-saturated and the gas reading from the mud during drilling, is consistently low towards the base of the C Sand. In general, the core porosity (percussion sidewall cores) in Karish-1 compares well with the log-derived porosity over the clean sandstone intervals. However, the log derived porosity is pessimistic in some reservoir intervals primarily where there is an increase in clay content. This suggests that the clays in the sidewall cores have been dried and/or the sidewall core has been damaged on acquisition.

The application of the high resolution borehole resistivity and acoustic image logs in Karish-1 has significantly improved the net pay estimation, particularly in the thinly bedded A and B Sand Units. The net pay in the A Sand increased by 85% (from 4.6 m to 8.5 m), whereas the net pay in B Sand increased by 130% (from 4.5 m to 10.4 m), compared to the results using conventional logs. As the C Sand Unit consists of massive and thick clean sands, the total net pay does not vary significantly between the image and conventional log interpretations.

3.3 Tanin-1 Overview

Tanin-1 is interpreted to contain a total of 32.3 m net gas-bearing sandstones within the A and B Sand Units. The gas-water contact is interpreted at 5118.0 mMDRT (5095m TVDSS) based on the formation pressure gradient plotted from pressures obtained in the A and B Sand Units. The core porosity in Tanin-1 does not have a good match with the log-derived porosity, as the cores are thought to have been damaged during acquisition, by the percussion sidewall coring process.

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3.4 Petrophysical Analysis

3.4.1 Methodology

3.4.1.1 Vshale

The volume of shale calculated from gamma ray and SP, assuming a linear transform.

$$V_{sh} = \frac{GR - GR_{clay}}{GR_{clay} - GR_{clean}} \quad V_{sh} = \frac{SP - SP_{clean}}{SP_{clay} - SP_{clean}}$$

3.4.1.2 Lithology

From the lithology descriptions, the sediments generally consist of claystone and quartz rich sandstones. Therefore, the lithology evaluation in these wells is based on a breakdown into quartz, limestone and dolomite. The contribution of each mineral in the bulk volume of the rock was determined using the Umapp/RHUmapp cross plot (based on the PEF and density logs) or the RHUmapp/Dtmapp cross plot (based on the density and sonic logs).

3.4.1.3 Bad Hole Determination

“Bad hole” conditions occur where the pad tools are not in connection with the borehole wall. This results in unreliability in the logs, particularly the density. To define areas of “bad hole”, a single measurement is not enough. A smooth, large hole can still have good conditions, whereas a rough hole can result in unreliable readings. Therefore, “bad hole” is defined using a combination of two measurements: hole-size (calliper) and density correction (DRHO). The absolute values of each of these parameters vary, depending on different bit sizes and well conditions.

3.4.1.4 Porosity

Porosity was primarily calculated from the density log and density/neutron cross plot. Porosity was also derived from the sonic log based on the Raymer-Hunt-Gardner equation and utilised over areas designated as “bad hole”. The porosity curve is calibrated with the porosity measured from the routine core analysis, where core is available.

3.4.1.5 Cementation exponent, “m” and Saturation exponent, “n”

In situations where no special core analysis data is available, the cementation exponent, m, was set to 2.00, with the coefficient, a, was set to 1.00 and the saturation exponent, n, assumed to be 2.00.

3.4.1.6 Water Saturation

In sand-shale reservoirs, the water saturation (Sw) is calculated using the Indonesian (Poupon-Leveaux) equation:

$$\frac{1}{\sqrt{Rt}} = \left(\sqrt{\left(\frac{\phi h^m}{a * R_w} \right)} + \frac{(Vcl)^{(1-Vcl)/2}}{\sqrt{Rcl}} \right) * S_w^{\left(\frac{n}{2}\right)}$$

Formation water salinities (ppm NaCl equivalent) have been derived from logging logs using methods such as Pickett plot and SP, and compared to any water samples recovered. The Pickett plot is a logarithmic cross plot

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of true resistivity (R_t) and porosity, which results in a straight line of water saturation with a negative slope of cementation exponent “ m ”. For water saturation value less than 100%, the lines will displace to the right of the cross plot.

The porosity logs generally have a shallow depth of investigation that is measuring in the flushed zone. An estimate of water saturation seen by the porosity tools (S_{xo}) is therefore required for porosity determination and invasion correction. To investigate the movability of hydrocarbons is to determine water saturation of the flushed zone (S_{xo}). This is accomplished by substituting into the Archie equation those parameters pertaining to the flushed zone. S_{xo} is derived using from the same Indonesian (Poupon-Leveaux) equation used to derive S_w . Parameters in the equation are substituted as follows; R_{mf} for R_w , R_{xo} for R_t , R_{mfb} for R_{wb} and R_{xoCl} for R_{cl} . The final S_{xo} curve was then applied with limits depending on types of drilling mud (i.e. oil-based mud or water-based mud), in order to give a sensible water saturation values. For this study, water-based muds were used to drill the two wells. Water-based muds introduce additional water into the formation and hence the S_{xo} will always be greater than or equal to S_w . Therefore, in this drilling mud environment, the saturations are limited using the following logic:

$$S_{xo} \leq S_w^{S_{xo} \text{ limit}}$$

3.4.1.7 Reservoir Determination

To discriminate between reservoir and non-reservoir rocks, a shale and porosity cut-off have been applied to each sample point. Several cut-off values for shale and porosity has been used to estimate the range of hydrocarbon volume in place for this area. Results are evaluated based on the high case, reference case and low case, by applying a shale cut-off ranging from 40-60% and porosity cut-off that ranges from 8-10%.

3.4.2 Log Editing Workflow

The quality of the recorded elastic logs, such as density, compressional sonic and shear sonic were affected in some intervals by wellbore washout, casing points, gaps and missing data. These were due to the various conditions, such as logging through casing, “bad-hole” conditions, logging tools that were not working properly, etc. Therefore, the original elastic logs, if required, were environment-corrected, despiked, filtered to remove the anomalous data points and depth matched.

Synthetic data was also generated using rock physics trends and Gassmann fluid substitution theory over the missing data intervals and “bad-hole” affected logs (i.e. density log in general). The Gassmann theory will be discussed in the next sub-topic (Methodology of mud filtrate invasion correction). To demonstrate the reliability of the reservoir and non-reservoir trends, a synthetic density, compressional sonic (DT) and shear sonic (DTS) have been generated for Karish-1 (Figure 3-1) and Tanin-1 (Figure 3-2) wells. Note that, in Karish-1, most of the interpreted section shows good agreement with the recorded logs for, density, compressional sonic and shear sonic. However, the shaley section, in the Serravallian unit (4250-4280 m) the logs tend to be “bad hole” affected (particularly density log) as indicated by the rugose calliper and low density readings, therefore the density log was patched with the synthetic density for the final set of elastic logs.

In this study, both wells have recorded shear sonic data, although Tanin-1 only has shear data available from 3616.0-4618.8 mMDRT. Therefore, the synthetic shear sonic has been generated and used for Tanin-1 to extend the log down to 5500.9 mMDRT. The method uses a mixed lithology input of sand/shale trends that have been derived from the statistical rock physics model and Gassmann fluid substitution theory. The V_p/V_s relationships for various lithologies were derived using the shear sonic from the two wells. The mixed lithology has been backed out using the petrophysical interpretation, i.e. volume of clay, water saturation and porosity curves.

The final step of log editing workflow is to then apply invasion corrections on the elastic curves, to correct the elastic logs from the effect of mud filtrate.

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3.4.3 Methodology of Mud Filtrate Invasion Correction

The recorded elastic logs, such as density, compressional sonic and shear sonic are often affected by mud filtrate invasion, over permeable intervals. Invasion occurs in porous and permeable formations by drilling mud due to the imbalance of hydrostatic pressure and formation pressure. The mud filtrate invasion affects tools with a shallow depth of investigation, such as the sonic and density more than those tools with a deeper depth of investigation, such as the deep induction resistivity. Therefore, invasion corrections are applied using Gassmann fluid substitution, over intervals with a Vsh cut-off of 50% and PHIT cut-off of 10%.

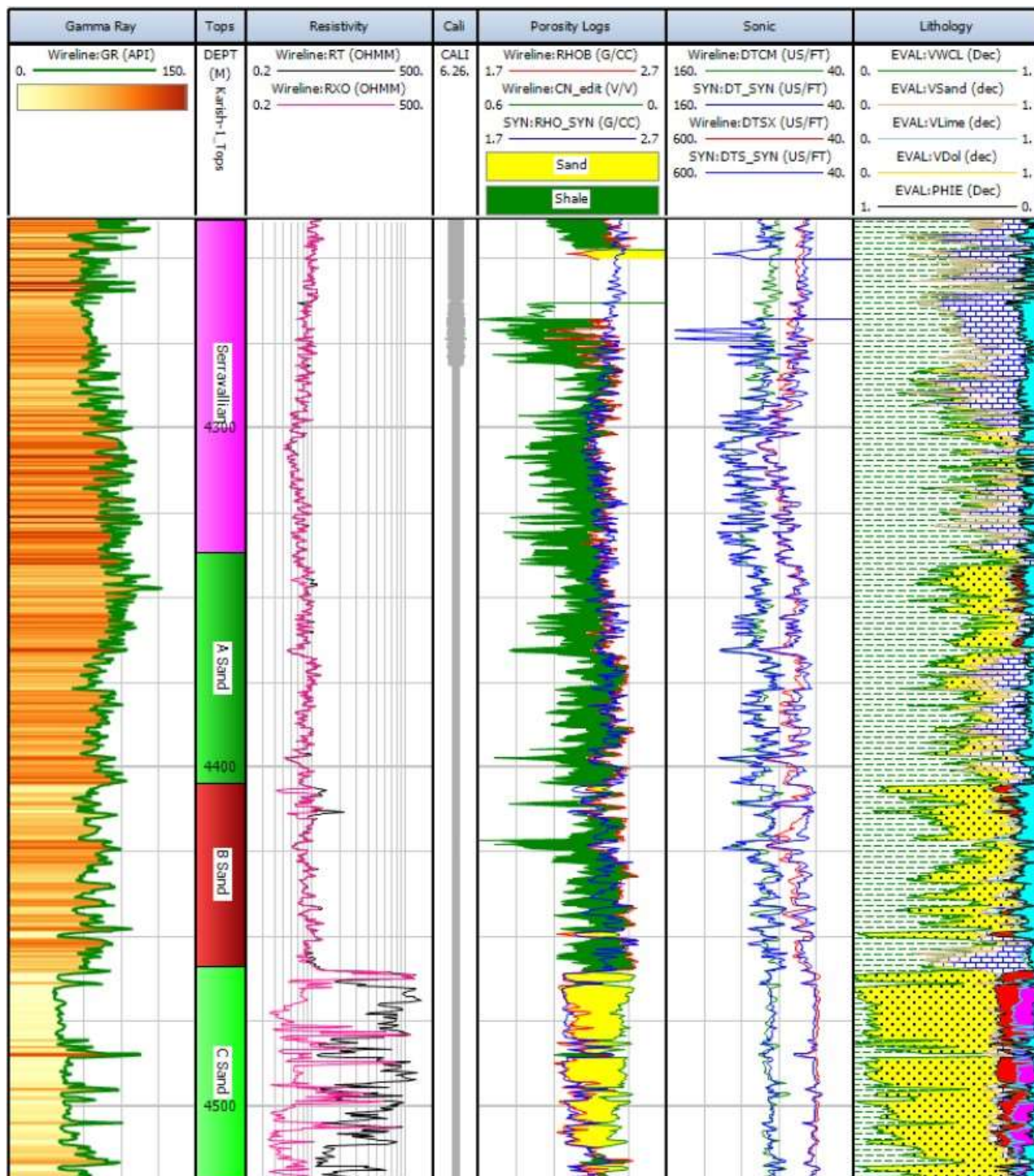


Figure 3-1 Karish-1 log analysis.

Figure Notes: Comparison of the synthetic density with the recorded logs section.

Synthetic DT and DTS shown as blue curves

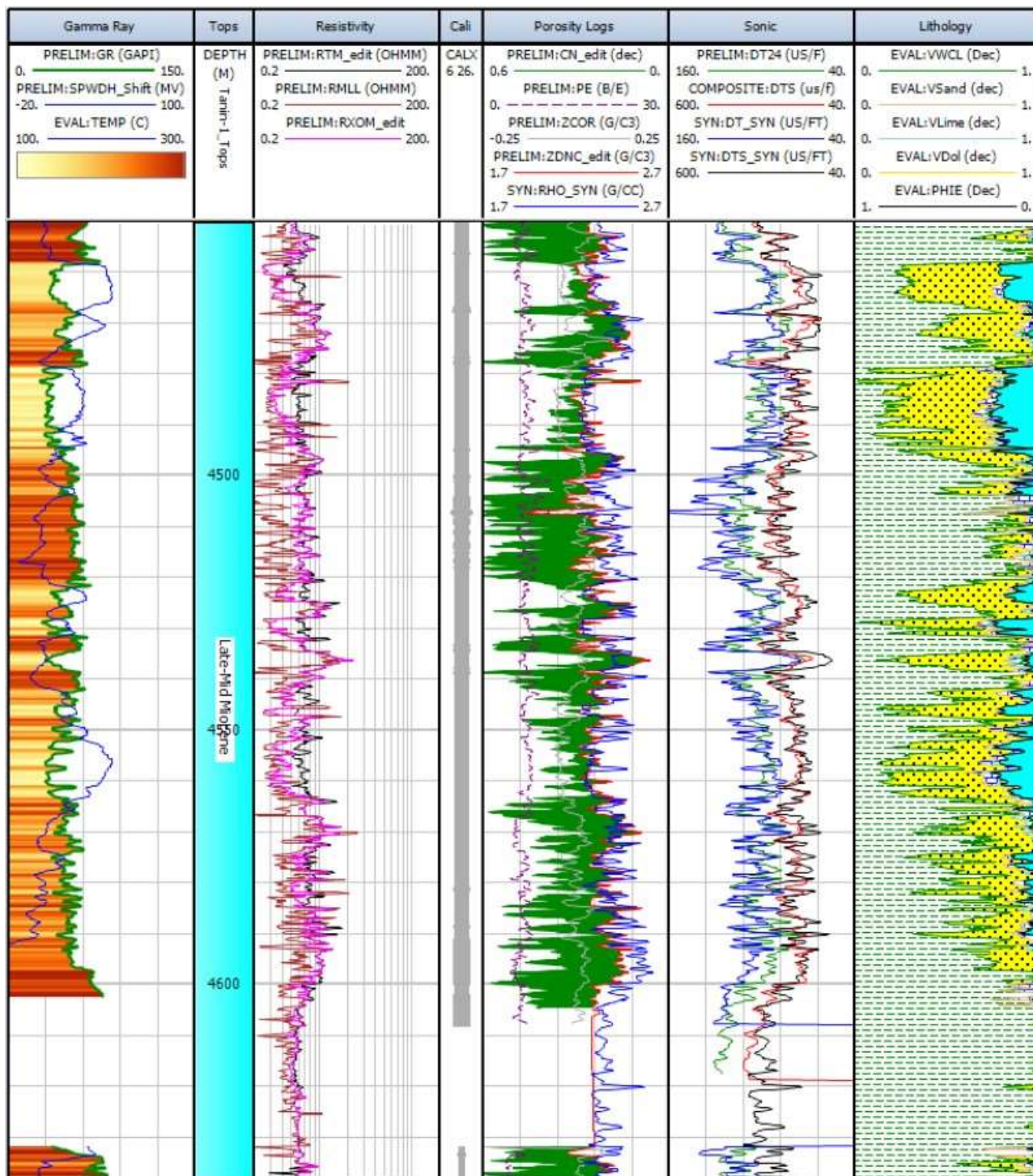


Figure 3-2 Karish-1 log analysis continued.

Figure Notes: Comparison of the synthetic density with the recorded logs section.

Synthetic DT and DTS shown as blue curves

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The first step is to quantify the extent of invasion using resistivity curves with multiple depth of investigations. For example, in Karish-1, the flushed zone-resistivity, RXO measures the flushed zone and RT measures into the virgin formation. The water saturation is calculated for both the flushed zone and the true formation using the Indonesian (Poupon-Leveaux) equation. The Sw curve is computed from the deep resistivity and the Sxo from the shallow resistivity.

The properties of water, oil and gas at true reservoir conditions are calculated using the BatzleWang formulas. Batzle and Wang (1992) provided generalised fluid properties, using empirical relationships between the in situ fluid to temperature, pressure, gas gravity, gas-oil ratio (GOR), oil density and brine salinity. Gassmann fluid substitution is then carried out using the calculated fluid properties to derived a new set of elastic logs i.e. density, compressional sonic and shear sonic at reservoir conditions before invasion.

Gassmann's equation relates the saturated bulk modulus of the undrained rock (Ksat) to its porosity (O), the bulk modulus of the porous rock frame (K*), the bulk modulus of the mineral matrix (Ko) and the bulk modulus of the pore-filling fluids (Kfl) as shown in equation (1). The calculation involves two main flows, where the bulk modulus of the porous dry rock frame prior to its initial pore fluid is calculated. The bulk modulus of the rock-saturated with the desired new fluid will then be calculated.

The process of fluid substitution involves the calculation of the saturated bulk modulus of undrained rock Ksat using wireline logs in equation (2). Consequently, the shear stiffness is determined from wireline logs in equation (3). The modulus of the mineral matrix is calculated using the average of harmonic (Reuss) and arithmetic (Voight). The two or more fluid mixing phases were calculated using Reuss average. The K*, bulk modulus of the porous rock frame is then calculated by rearranging equation (1). The new density, Vp and Vs are then determined using equation (4) to (6).

$$K_{sat} = K^* + \frac{(1 - \frac{K^*}{K_o})^2}{\frac{\phi}{K_f} + \frac{(1 - \phi)}{K_o} - \frac{K^*}{K_o^2}} \quad \text{----- (1)}$$

$$\rho_B = \rho_g (1 - \phi) + \rho_f \phi \quad \text{----- (4)}$$

$$K = \rho_B (V_p^2 - \frac{4}{3} V_s^2) \quad \text{----- (2)}$$

$$V_p = \sqrt{\frac{K_{Sat} + \frac{4}{3} G}{\rho_B}} \quad \text{----- (5)}$$

$$G = \rho_B V_s^2 \quad \text{----- (3)}$$

$$V_s = \sqrt{\frac{G}{\rho_B}} \quad \text{----- (6)}$$

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3.5 Karish-1: Petrophysical Analysis Results

3.5.1 Available Data

3.5.1.1 Wireline Logging

Wireline logging was carried out by Baker Atlas down to the total depth of 4805 mMDRT as summarised in Table 3-1.

3.5.1.2 MWD/LWD Logs

LWD logs were acquired by Baker Hughes INTEQ and summarised in Table 3-2.

3.5.1.3 Conventional Cores/Sidewall Cores

A total of 50 PSWC (Percussion Sidewall Core) were attempted over the interval of 4305.0-4764.6 mMDRT with 48 considered to be good samples, and 2 were lost, which resulted in 96% recovery.

3.5.1.4 Formation Testing

A total of 45 pressure test points were attempted using the RCI over the interval of 4341-4667 mMDRT, resulting in 37 good tests, 7 were tight and 1 had a lost seal. During the run, a total of 12 formation fluid samples were recovered and the details of the fluid samples are summarised in Table 3-3.

3.5.1.5 Hole Condition

The hole and casing details are summarised in Table 3-4.

The logging measurements, in particular the density log, are affected by poor hole condition, particularly in non-reservoir lithology, over the intervals of 3556-3586 and 4247-4282 mMDRT, due to hole washouts. Despite these conditions, the log responses are generally valid and did not affect the reliability of the petrophysical analysis. In porous sandstone intervals, the mud cake was well developed, resulting in a smaller hole diameter and good log responses. The Karish-1 well was drilled with a salt saturated water-based mud system. Details of the mud properties are summarised in Table 3-4.

3.5.2 Input Parameters

The shale parameters were obtained from various cross plot techniques. The input parameters used in the interpretation are presented in Table 3-5.

3.5.3 Temperature

Wireline logging measured a maximum bottom hole formation temperature of 81.1°C at 4812 mMDRT. Assuming a seabed temperature of 15.0°C, the geothermal gradient in the Karish-1 well is 2.17°C/100 m.

3.5.4 Water Salinity

The formation water salinity in Karish-1 well was primarily determined from the Pickett plot analysis, derived from known brine sandstone intervals, and compared to the water analysis results.

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A Pickett plot over the interval of 4458.8-4595.0 mMDRT within the C Sand (Figure 3-3) indicates that the formation water resistivity, R_w is 0.222 Ω m at 25.0°C, which equates to a formation water salinity of 27,000 ppm NaCl equivalent. This value has resulted in close to 100% water saturation in clean water-bearing sandstones. This formation water salinity value is comparable to that determined from the water analysis result of the RCI sample taken at 4553.4 mMDRT. Using the Schlumberger's Empirical Ion Multiplier Chart (Figure 3-4), this method yields a calculated formation water salinity of 27,860 ppm NaCl equivalent.

3.5.5 Discussion of Results

A summary of the reservoir intervals is presented in Table 3-6 which is based on the “most-likely case” (using the S_w derived from the saturation height function) and will be discussed further in this section.

3.5.5.1 A Sand

Based on petrographic study on the sidewall core sample, reservoir in this unit consists of argillaceous calcareous siltstone, which contains abundant monocrystalline quartz, moderate potassium feldspar with minor plagioclase, argillaceous and igneous rock fragments. Based on the drilling report, the A Sand was poorly developed although good gas shows were noted and the RCI data confirmed some poor to fair mobility in this sand.

A total of 6.7 m net gas sandstone is interpreted over the interval of 4340.4-4355.3 mMDRT, with an average porosity of 15.1% and average water saturation of 36.8% (Figure 3-5). The presence of gas is confirmed by recovery of RCI sample at 4350.8 mMDRT which contained gas. There is also a gas peak observed at around 4352.0 mMDRT. Due to high clay content in this reservoir, the core porosities tend to match the log-derived total porosity (PHIT) compared to the effective porosity (PHIE).

3.5.5.2 B Sand

Sandstones in this unit are generally described as white to clear, very fine to medium grained, with occasional coarse grains. The grains are sub angular to sub rounded, moderate to well sorted and occasionally contain traces of ash and calcareous material.

Sandstones over the interval of 4405.2-4413.7 mMDRT are interpreted to have net gas pay of 6.9m, with an average porosity of 19.5% and average water saturation of 28.5%. The presence of gas is confirmed by the recovery of RCI gas sample at 4410.0 mMDRT (Figure 3-6). There is a good match between core porosity and the log-derived porosity (PHIT) in this reservoir.

A thin gas sand is interpreted at 4448.1-4450.7 mMDRT towards the base of the B Sand Unit with a net pay of 2.0m. This reservoir has an average porosity of 21.2%, with an average water saturation of 26.3% (Figure 3-6). A gas peak was observed at 4448 mMDRT.

3.5.5.3 C Sand

The C Sand reservoir holds the majority of the net gas pay in the Karish-1 well. Sandstones in this unit are generally described as white to clear and translucent in colour, mostly fine grained to coarse-grained, predominantly unconsolidated, moderately sorted and calcareous in part.

A total of 55.4 m net gas pay is interpreted over the interval of 4460.3-4544.0 mMDRT, with an average porosity of 19.8% and average water saturation of 35.7%. One RCI sample was recovered at 4489.0mMDRT which contained gas (Figure 3-7).

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Sandstones over the intervals of 4544.0-4596.4 mMDRT are interpreted to be essentially water saturated, with an average porosity of 16.0%. One RCI sample was recovered at 4553.4 mMDRT which contained water (Figure 3-7).

3.5.5.4 D Sand

Sandstones in this unit were generally described as white, clear and translucent in colour, mostly fine to coarse-grained, mostly unconsolidated, with friable to slightly consolidated. The grains are moderately sorted, sub rounded to rounded and occasionally contain calcareous material and trace amounts of chert.

A total of 56.4 m net water-bearing sandstone is interpreted over the interval of 4613.6-4703.1 mMDRT, with an average porosity of 17.6% and average water saturation of 96.4% (Figure 3-8).

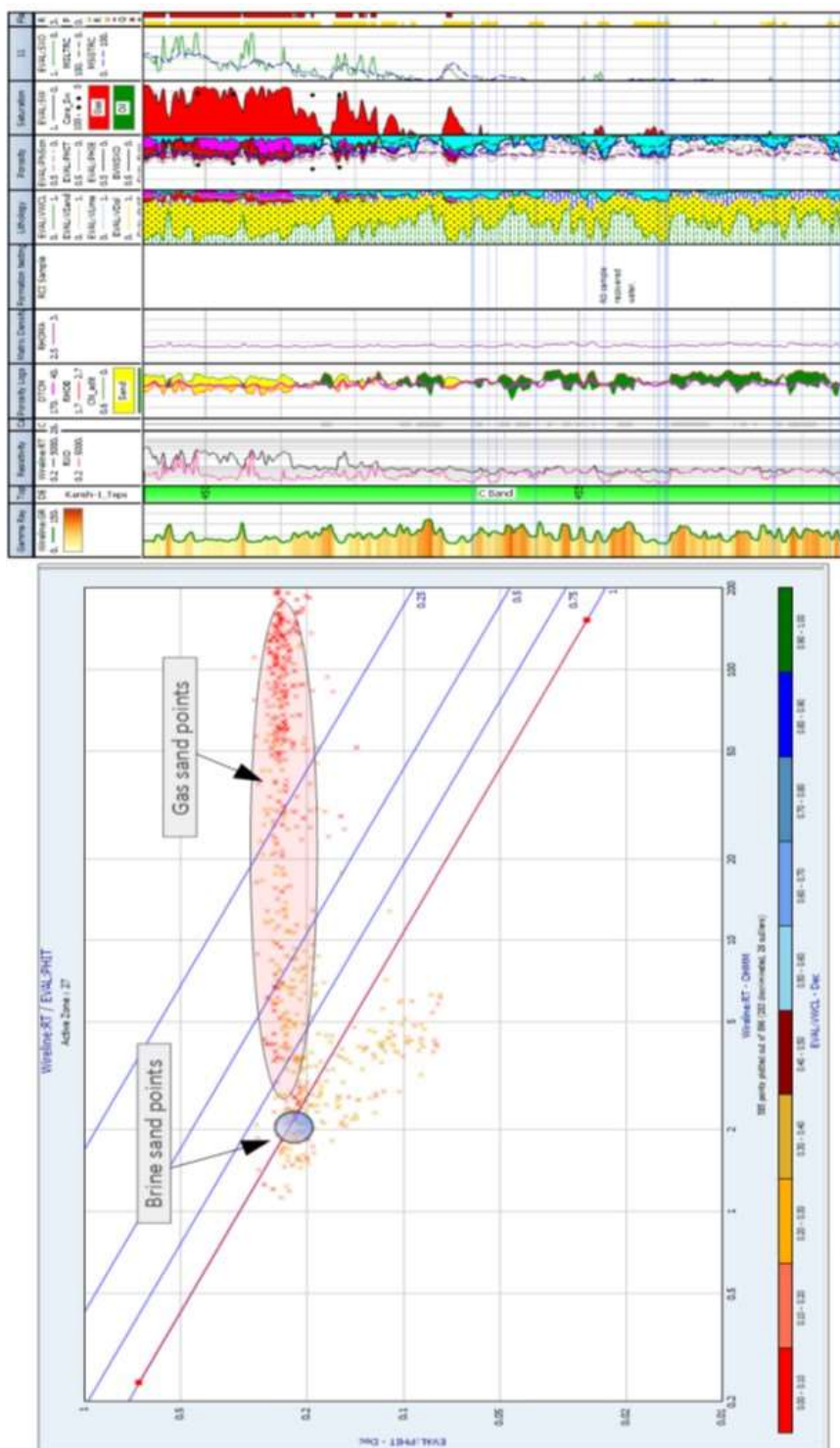


Figure 3-3 Karish-1 - Pickett plot over the C Sand Unit

Figure Notes: Rw of 0.222 ohm-m@25°C, which equates to a formation water salinity of 27,000 ppm NaCl equivalent.

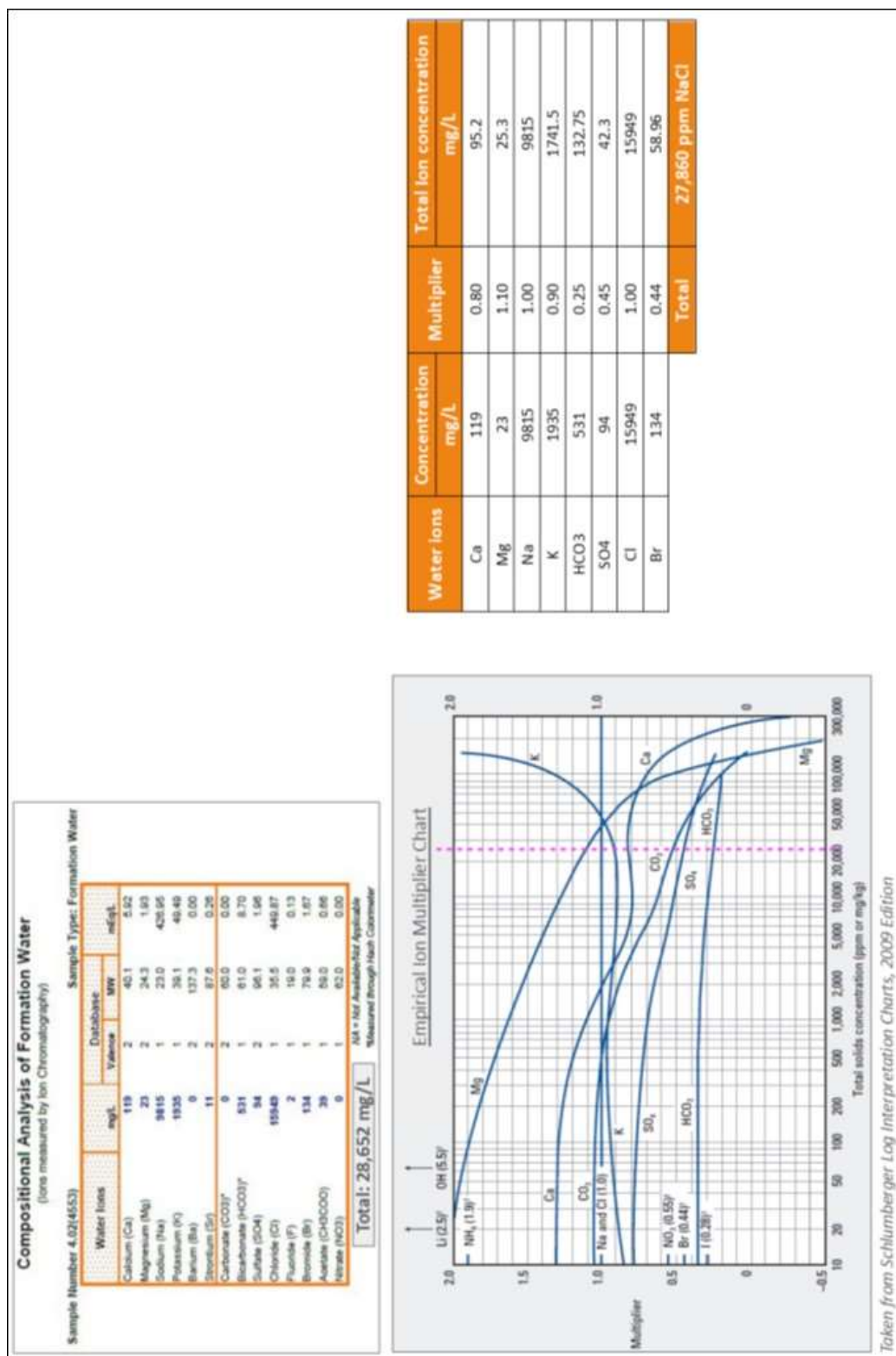


Figure 3-4 Karish-1 Formation water salinity

Figure Notes: Derived from the chemical composition in water sample analysis, yields a salinity of 27,860 ppm NaCl equivalent.

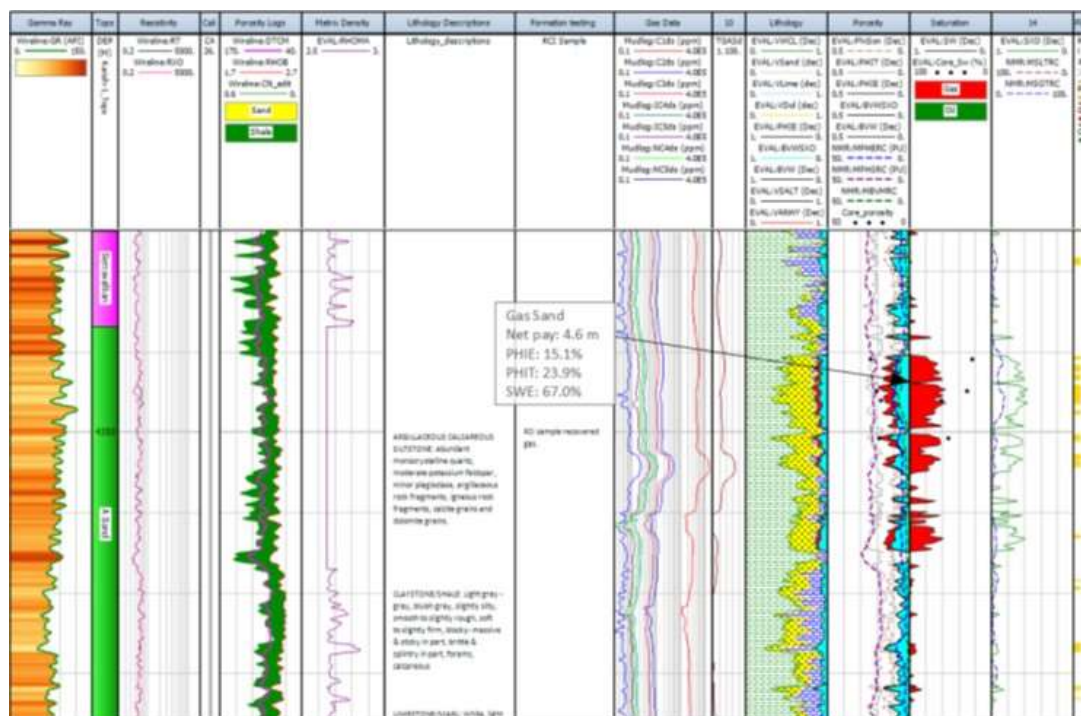


Figure 3-5 Karish-1, interpreted section of the A Sand Unit.

Figure Notes: A 4.6 m net gas pay is interpreted over the interval of 4340.4-4355.3 mMDRT, with an average porosity of 15.1% and 67.0% average water saturation.

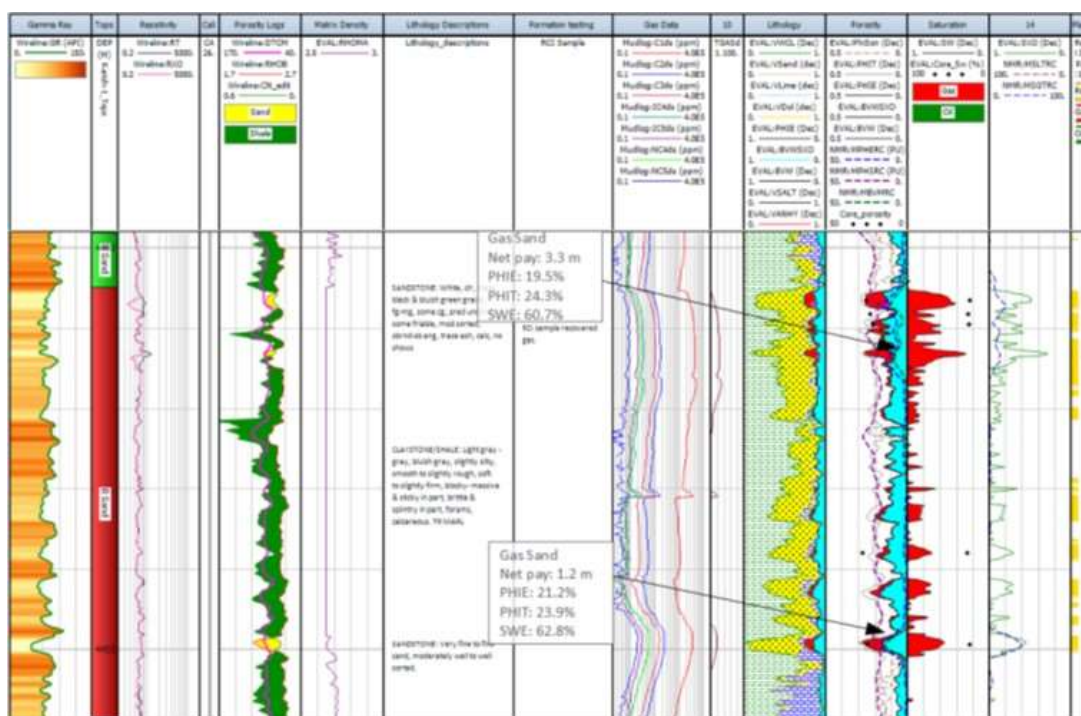


Figure 3-6 Karish-1, interpreted section of the B Sand Unit.

Figure Notes: 3.3 m and 1.2 m net gas pays are interpreted over the interval of 4405.2-4413.7 and 4448.1-4450.7 mMDRT respectively.

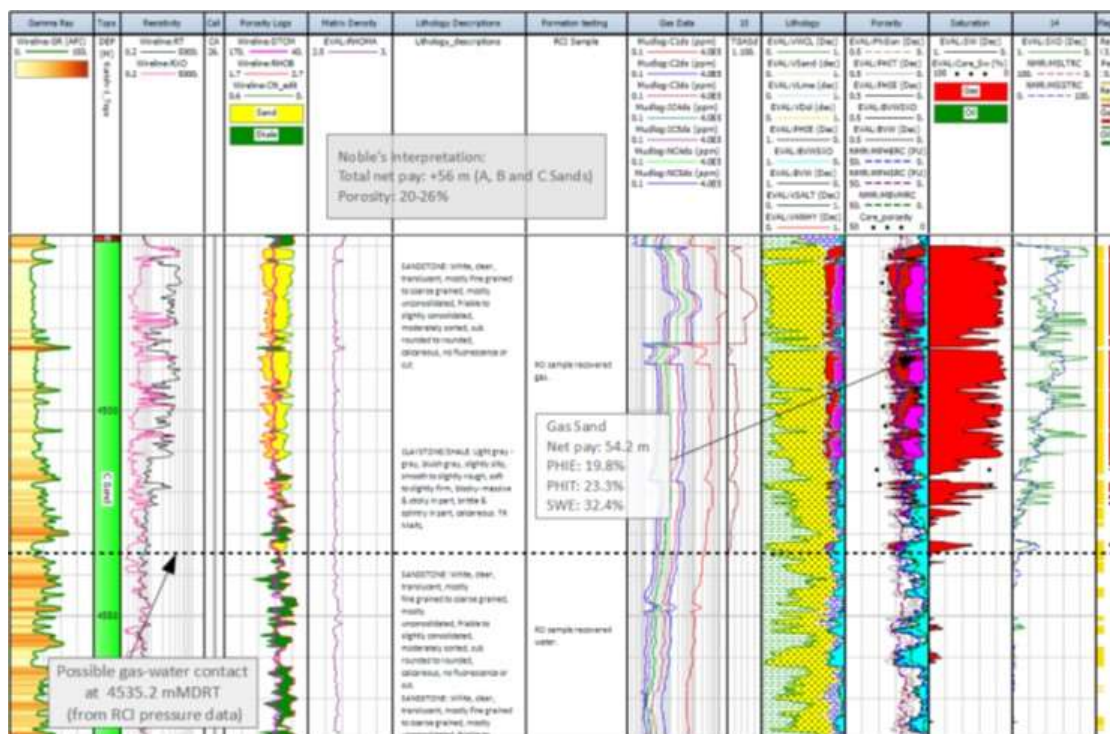


Figure 3-7 Karish-1, interpreted section of the C Sand Unit.

Figure Notes: A total of 54.2 m net gas pay is interpreted over the interval of 4460.3-4544.0 mMDRT. A gas-water contact is predicted at 4535.2 mMDRT. Below the GWC, a total of 17.5 m net water-bearing sandstone is interpreted from 4544.0 to 4596.4 mMDRT.

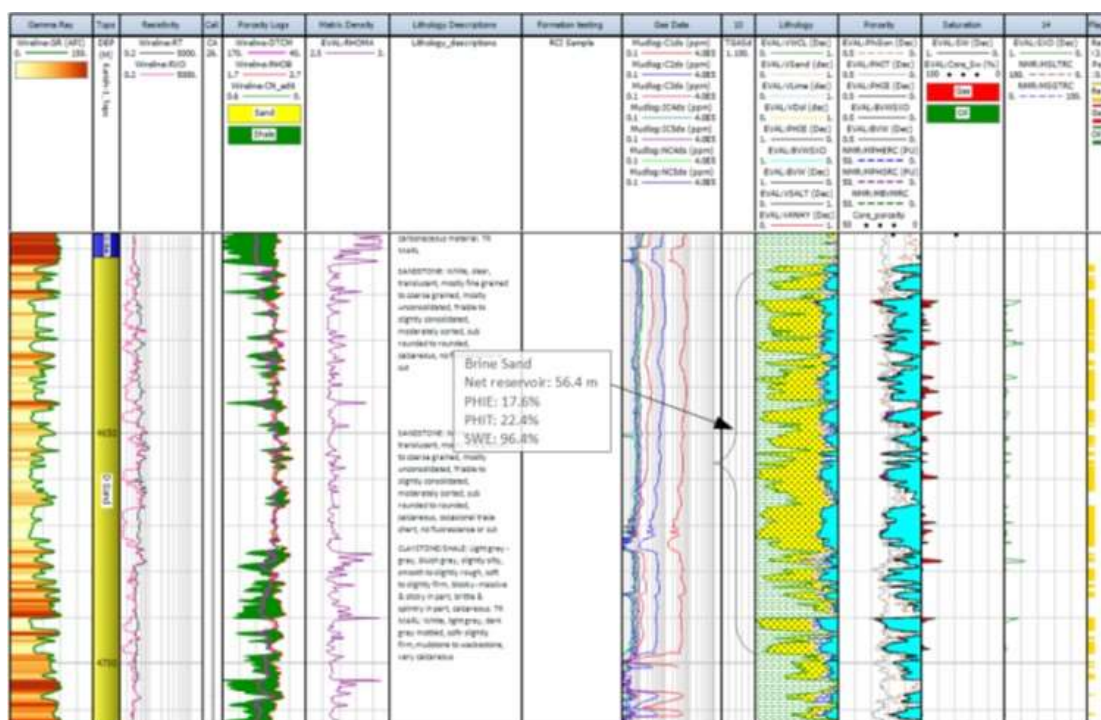


Figure 3-8 Karish-1, interpreted section of the D Sand Unit.

Figure Notes: A total of 56.4 m net water-bearing sandstone is interpreted over the interval of 4613.6-4703.1 mMDRT, with an average porosity of 17.6%.

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3.5.5.5 Comparison between various porosity methods (Density, Neutron-Density and Sonic porosities)

Porosity has been calculated over the gas sandstone in C Sand Unit using the density, neutron-density and sonic logs to assess the uncertainties of different porosity methods. Based on the interpreted section shown in Figure 3-9, the sonic porosity gives the highest porosity value compared to the other two methods as sonic porosity is affected by fluid property changes (gas effect). The fluid effect is more linear on the neutron and density logs and therefore the porosity evaluation using these tools is more reliable. The density and neutron-density porosities are relatively similar. The density porosity is preferable in this zone as it gives a good agreement with the core porosity in clean sandstone.

3.5.5.6 Comparison between well log interpretation to NMR results calibration

As the NMR logging tool has a relatively shallow depth of investigation, the tool readings can be affected by fluid invasion and borehole conditions in permeable zones. In general, a reasonable match between the NMR result curves and the well log-derived curves was observed (Figure 3-10).

3.5.5.7 Image Analysis

The resistivity and acoustic image logs were run with the Baker Hughes STAR-CBIL tool over the interval of 4260.0-4788.0 mMDRT. The high resolution image logs have confirmed the presence of highly laminated sand-shale sequences, particularly within the A and B Sand Units. When the beds are less than approximately 2 ft. thick, they are classified as thin beds and are below the resolution of many of the conventional logging tools. In the earlier discussion, it was suggested that the resistivity measurements are affected by thin conductive shale layers. Hence the saturation height function was applied to determine water saturations.

The next area of uncertainty is the net pay thickness. Thus, using the provided high resolution image logs (~5 mm resolution), the estimation of net pay in the thinly bedded sands can be improved. The workflow started with the determination of bed boundaries from both resistivity and acoustic image data. The high resolution acoustic and resistivity logs were cross-plotted in linear to log scales and the classification of different lithofacies were identified (Figure 3-11). Subsequently, the areas and boundaries were determined for each lithofacies. Four lithofacies were classified namely as Shale (Facies 0), Shaly-sand (Facies 1), Laminated Sand (Facies 2) and Good Quality Sand (Facies 3). For the net pay determination, Facies 0 is considered as “non-pay”, whereas Facies 1, 2 and 3 were considered as “pay”.

Facies 0 is characterized by higher resistivity and higher reflectance travel time compared to Facies 1, 2 and 3. Based on petrophysics interpretation, this facies is captured mostly at very high clay volume intervals (shale prone) and is considered as non-pay. Facies 1, which is referred to as “Shaly Sand” facies has similar reflectance travel time, but with slightly lower resistivity compared to Facies 0. In comparison with Facies 2, this facies has higher reflectance travel time and considered as the “shalier” laminated sand. Facies 2 is considered as the “better developed laminated sandstone” compared to Facies 1. This facies has higher resistivity compared to Facies 3 and referred to as “Laminated Sand” facies. Facies 3 has lower resistivity (flushed zone) compared to all facies and captured mostly in clean and thick gas-bearing sandstones and referred to as “Clean Sand” facies. Results of the net pay estimation based on the image log are summarised in Table 15. Based on this method, a total of 8.5 m net pay is calculated in the A Sand Unit (Figure 3-12 and Figure 3-13), which has increased by 85% compared to the net pay calculated from the conventional log interpretation (4.6 m). In the B Sand Unit, the net pay has increase from 4.5 m to 10.4 m (130%). Note that the net pay from the image log is thought to be overestimated at 4450-4453 mMDRT due to possible tool failure and therefore has not been included (Figure 3-14). The C Sand Unit has a slight increase (~5%) in the total net pay, from 54.2 m (using the conventional log interpretation) to 57.0 m (using the image log interpretation). This is not unexpected as this sand unit consists of massive and thick clean sand compared to the A and B Sand Units (Figure 3-15).

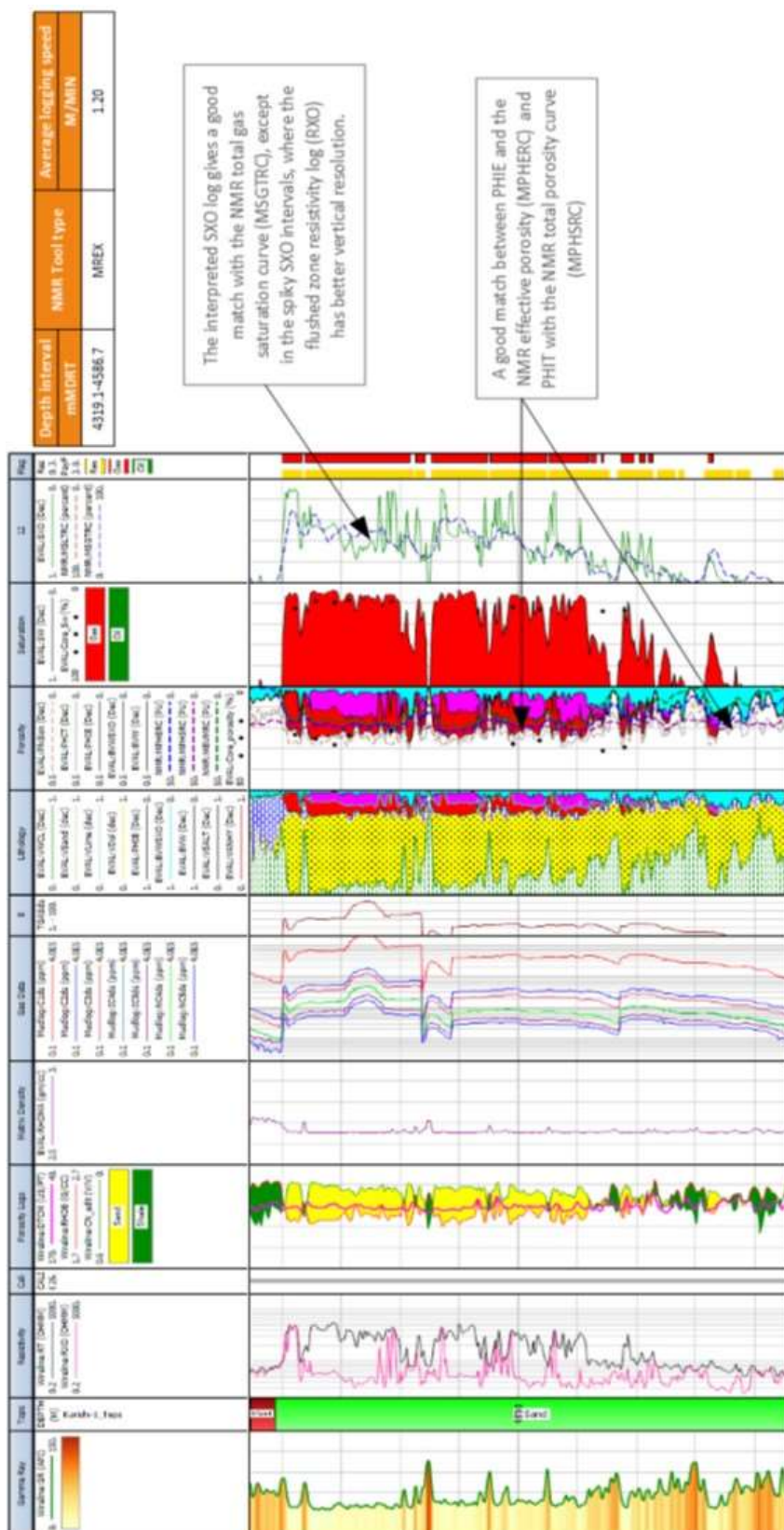


Figure 3-10 Karish-1, well log interpretation to NMR results calibration.

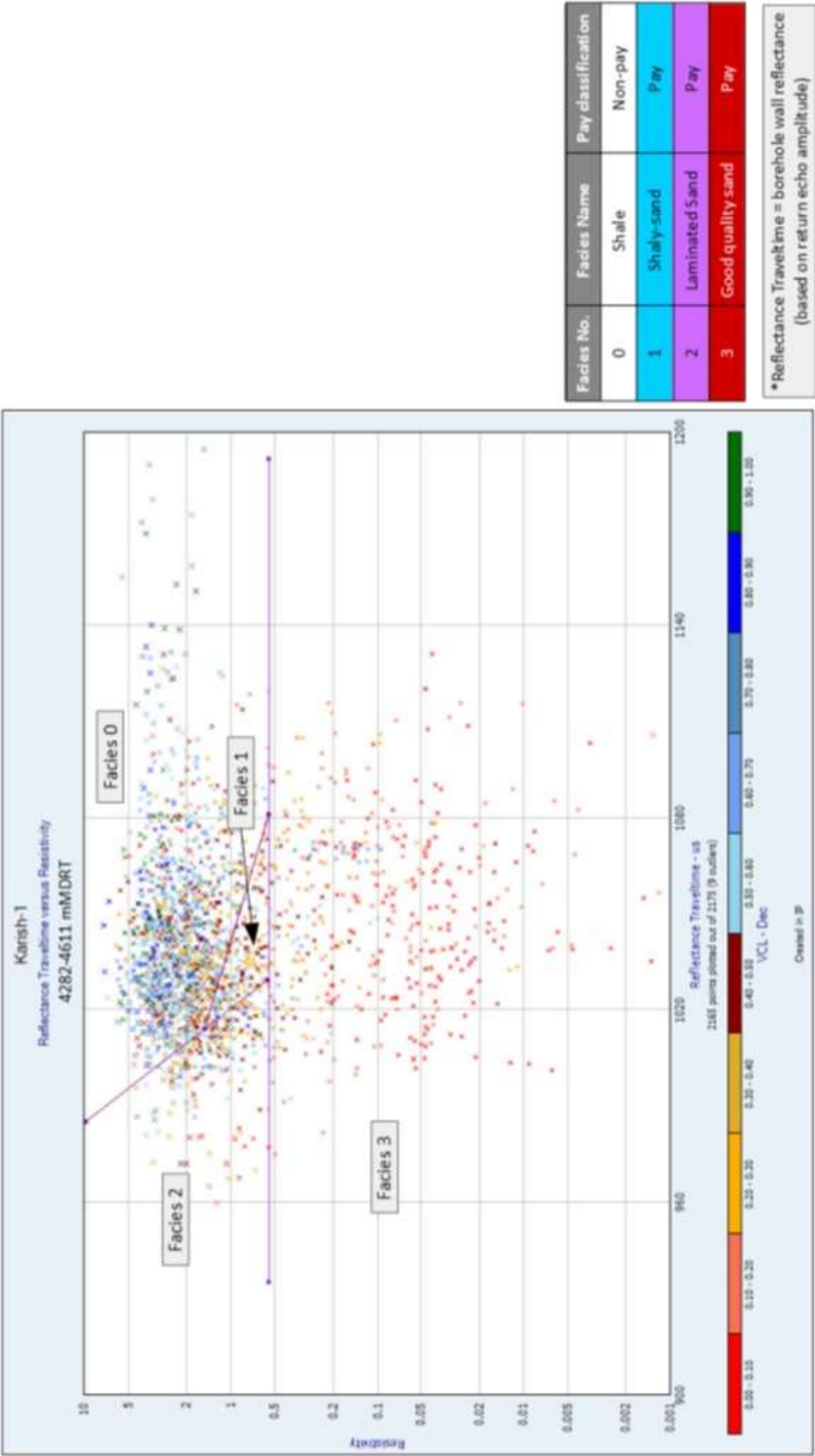


Figure 3-11 Karish-1, cross plot.

Figure notes: Reflectance Travel time versus Resistivity and classification of the lithofacies.

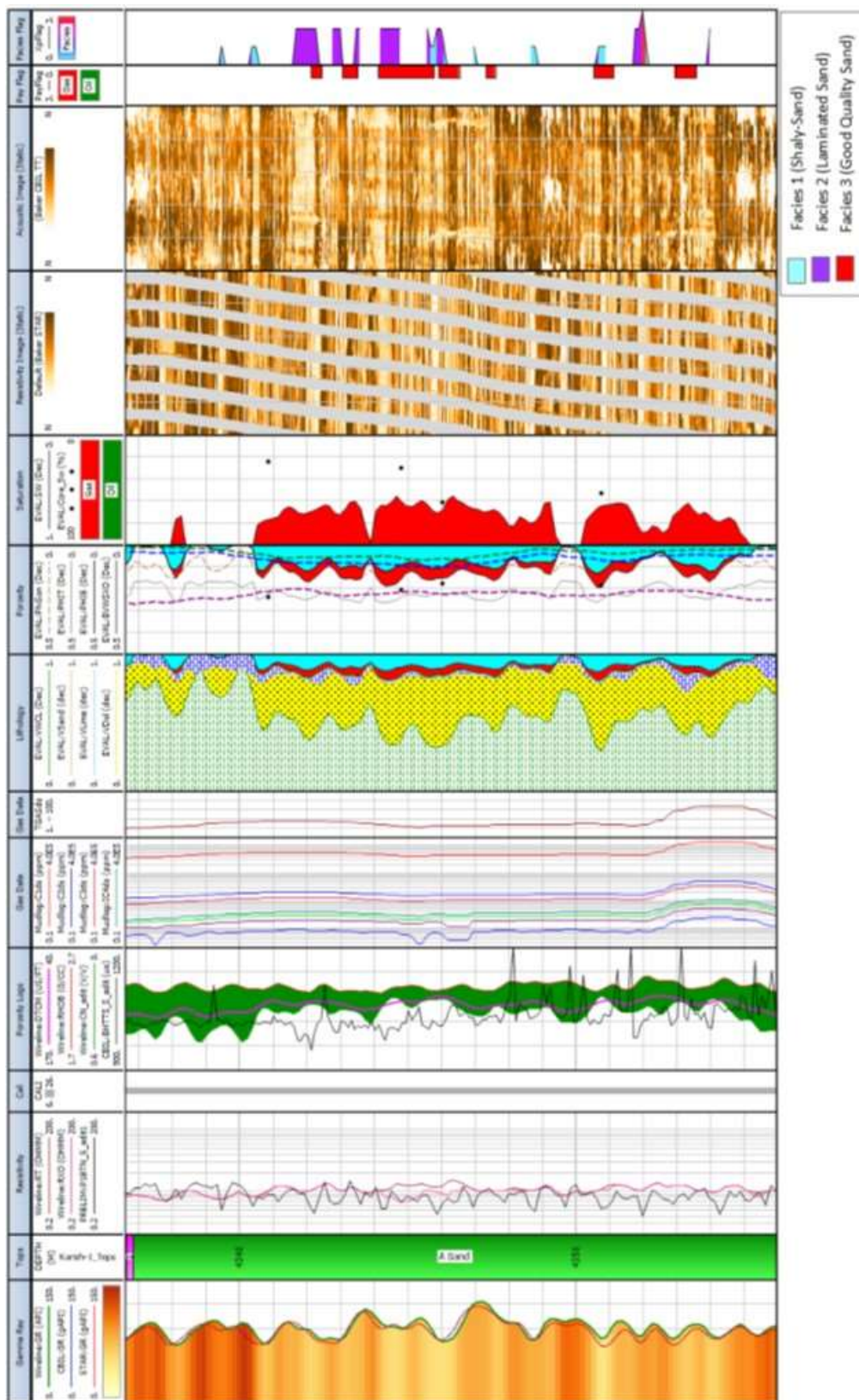


Figure 3-12 Karish-1, interpreted section of the A Sand Unit (upper section)

Figure Note: Showing the resistivity and acoustic image logs, with facies flag in the last column.

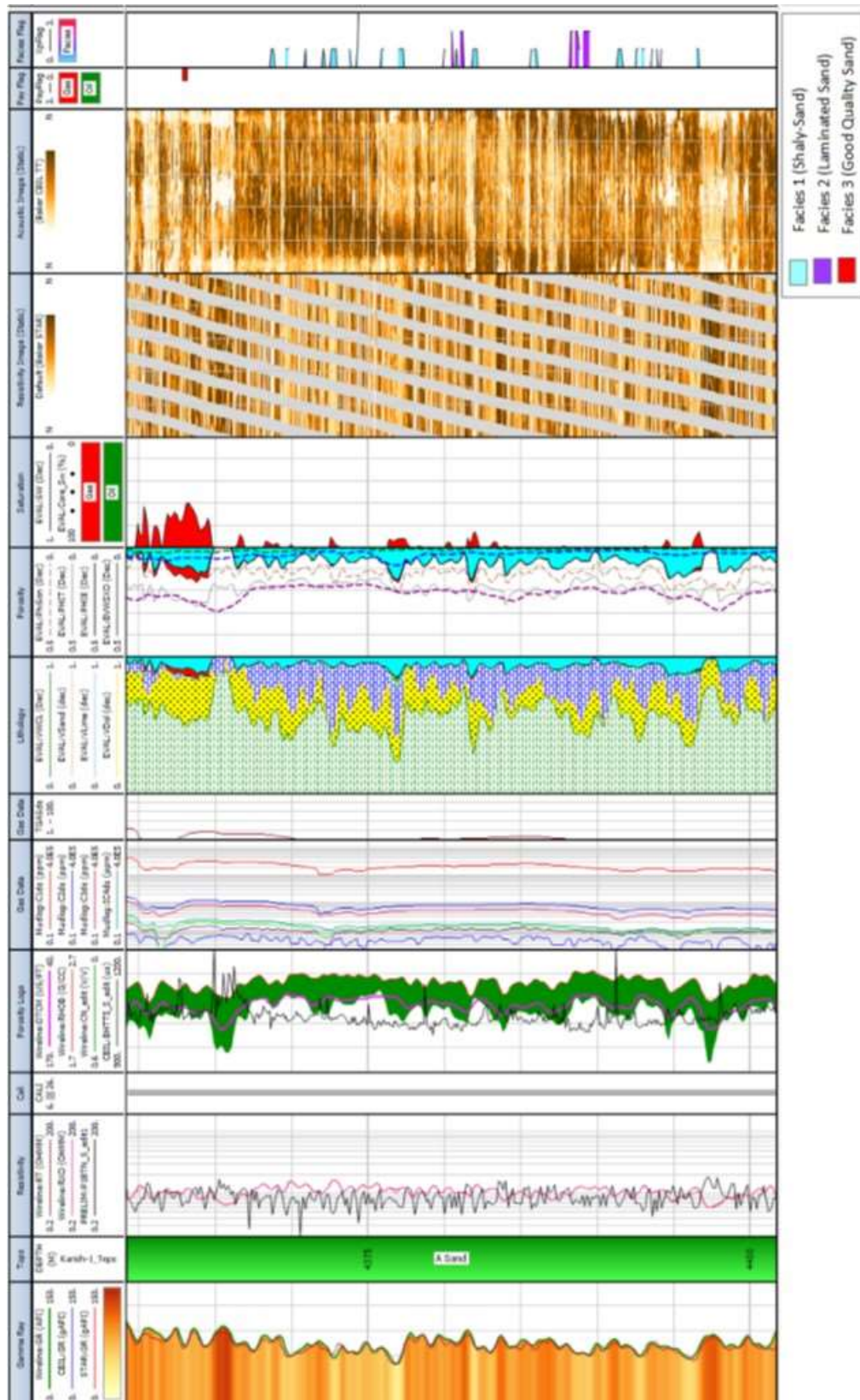


Figure Note: Showing the resistivity and acoustic image logs, with facies flag in the last column

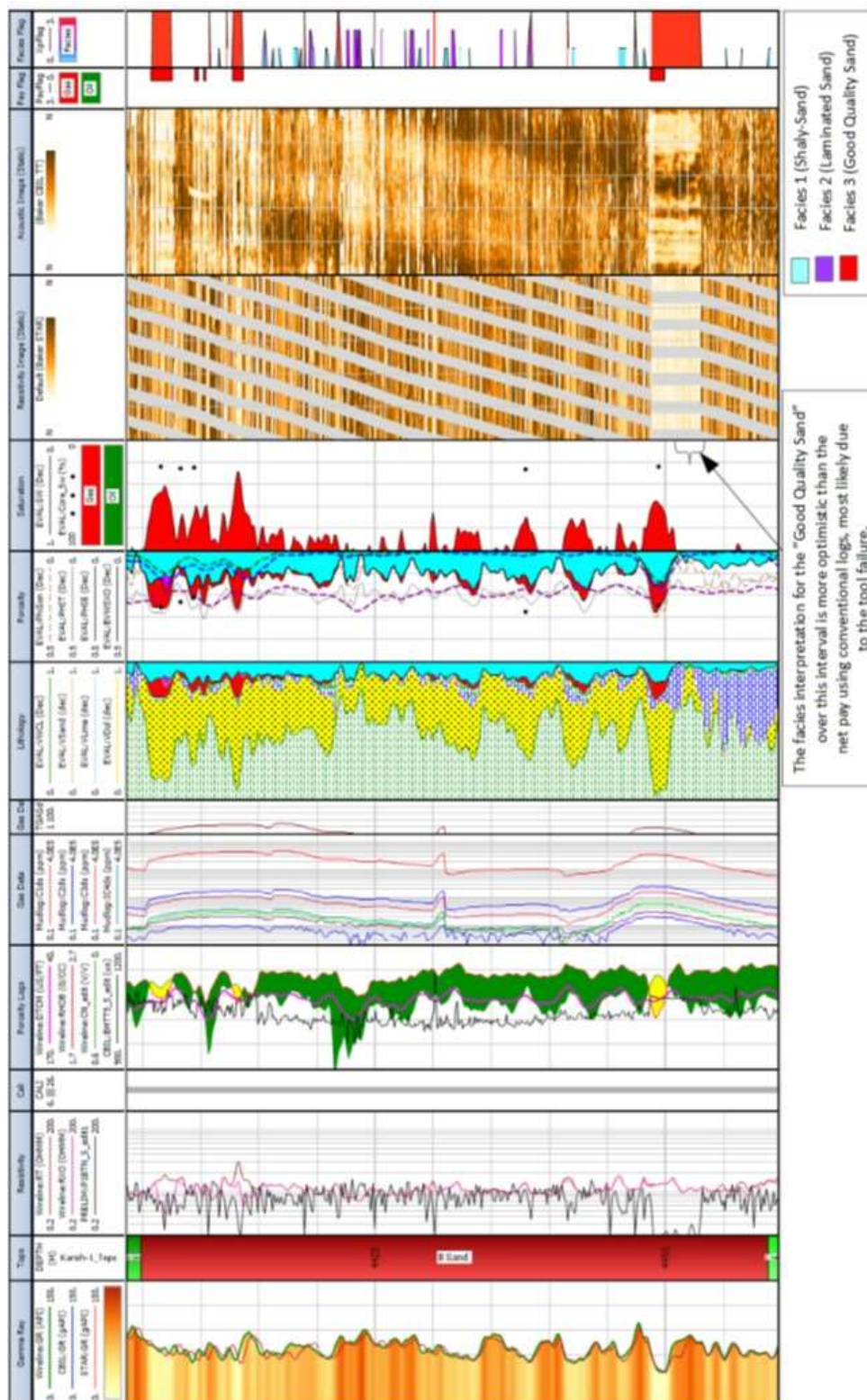


Figure 3-14 Karish-1, interpreted section of the B Sand Unit:

Figure Note: Facies flag in the last column. Shows the resistivity and acoustic image logs

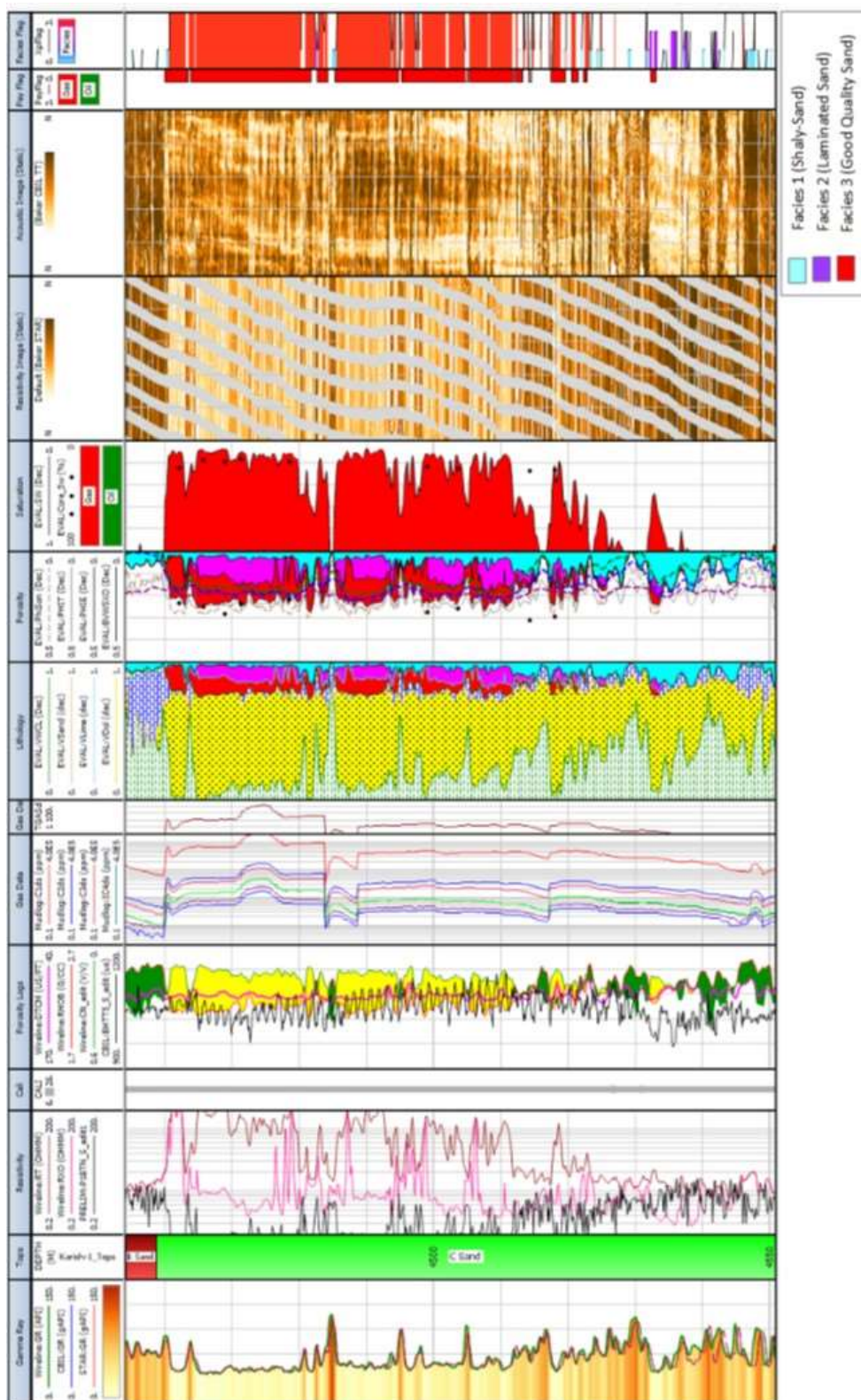


Figure 3-15 Karish-1, interpreted section of the C Sand Unit

Figure Note: Facies flag in the last column. Shows the resistivity and acoustic image logs

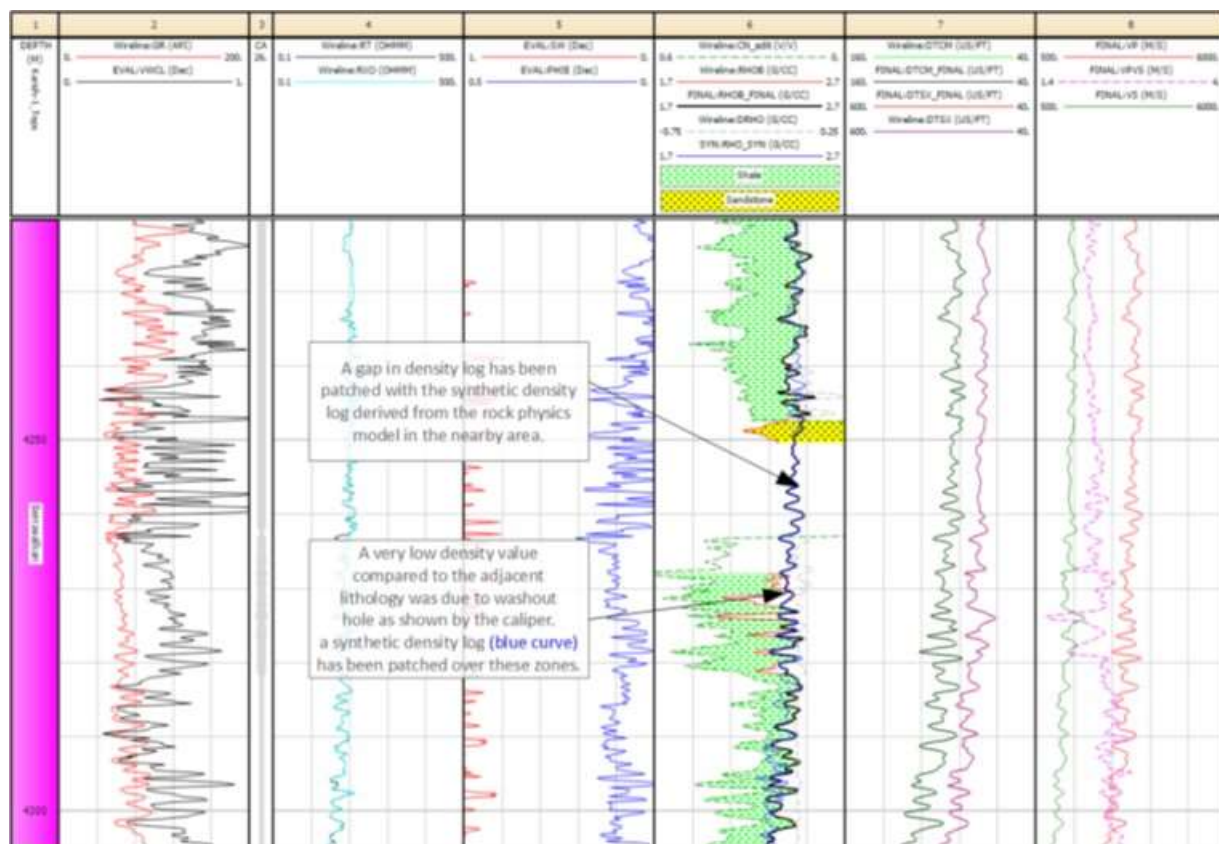


Figure 3-16 Karish-1, composite plot of the Serravallian section.

Figure Note: comparing the original and the final elastic logs.

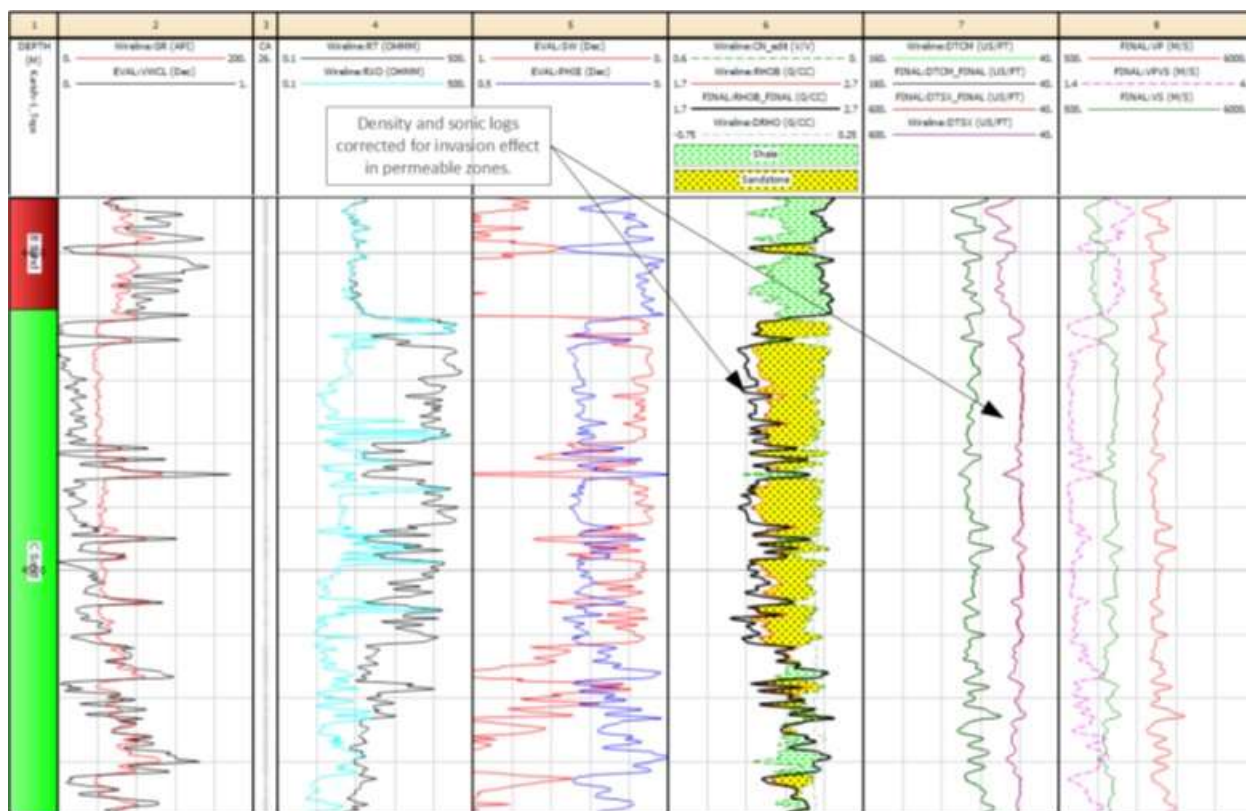


Figure 3-17 Karish-1, composite plot of the B and C Sand sections.

Figure Note: Showing the final elastic logs corrected for invasion effect in permeable zones.

Table 3-1 Karish-1, wireline logging.

RUN NO.	DEPTH INTERVAL	HOLE SIZE	WIRELINE SUITE	MAX TEMPERATURE
	mMDBRT	(inch)		°F
1A	3177-1730	17.5	GR/ORIT/6CAL	95
2A	4270-2945	12.5	GSLAM	131
3A	4805-4195	8.5	GSLAM	178
3B	4792-4260		STAR-ECBIL	162
3C	4586-4320		MREX	156
3D	4667-4341		RCI	162
3E	4775-1760		VSP	n/a
3F	4768-4305		PSWC	170

Table 3-2 Karish-1, LWD operation

RUN NO.	LWD LOG RUNS	DEPTH INTERVAL
	mMDBRT	mMDBRT
1	DIR/GR/Resistivity/APWD	1762.0-1833.5
1	DIR/GR/Resistivity/APWD	1833.5-2615.0
2	DIR/GR/Resistivity/APWD	2615.0-3178.8
3	DIR/GR/Resistivity/APWD	3178.8-4279.0
4	DIR/GR/Resistivity/APWD	4279.0-4812.0

Table 3-3 Karish-1, RCI samples

DEPTH	FORMATION PRESSURE	FORMATION TEMP	FLUID PROPERTY
MMDBRT	PSIA	°F	
4350.8	7850.06	150.7	Gas
4410.0	7839.58	154.8	Gas
4489.0	7867.48	159.9	Gas
4553.4	7913.06	159.6	Water

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Table 3-4: Karish-1, mud properties

HOLE SIZE (INCH)	DEPTH INTERVAL mMDBRT	CASING SIZE (INCH)	SHOE DEPTH mMDBRT
36	1762.0-1833.5	36	1833.5
26	1833.5-2615.0	20	2600
17.5	2615.0-3178.8	13 3/8	3164
12.25	3178.8-4279.0	9 5/8	4264.3
8.5	4279.0-4812.0		
Suite/Run	1	2	3
Bit Size (inch)	17.5	12.25	8.5
Log Start Depth (mMDBRT)	1730	2945	4195
Log End Depth (mMDBRT)	3177	4270	4803
Mud Type	KCL/NACL SS POLY	KCL/NACL SS POLY	KCL/NACL SS POLY
Mud Weight (lb/g)	11.3	11.7	11.3
Rm @ Measured Temp (°F)	0.0387 @ 66.5	0.0390 @ 72.0	0.0479 @ 69.8
Rmf @ Measured Temp (°F)	0.0765 @ 66.5	0.0431 @ 72.2	0.0411 @ 71.1
Rmc @ Measured Temp (°F)	0.0411 @ 66.6	0.0654 @ 71.7	0.0783 @ 66.8
Bottom Hole Temp (°F)	95	3131	178

Table 3-5: Karish-1, input parameters

Formation	Salt	Late-Mid Miocene		Serravallian				A Sand		B Sand		C Sand		CD Shale	D Sand
Top Depth (mMDBRT)	3163.1	3554.9	3823.8	4129.9	4196.8	4247.0	4281.6	4336.9	4367.0	4404.8	4448.5	4458.8	4595.0	4611.7	
Bottom Depth (mMDBRT)	3554.9	3823.8	4129.9	4196.8	4247.0	4281.6	4336.9	4367.0	4404.8	4448.5	4458.8	4595.0	4611.7	4201.0	
Shale	RHosh (g/cc)	-	2.21	2.20	2.25	2.43	2.43	2.43	2.45	2.45	2.49	2.49	2.44	2.33	2.37
	NPHish (p.u)	-	0.671	0.682	0.630	0.427	0.936	0.425	0.454	0.413	0.411	0.381	0.461	0.520	0.542
	DTsh (us/ft)	-	131	131	129	110	110	111	111	102	111	100	100	113	110
	Rsh (ohmm)	-	1.54	2.16	1.91	5.38	4.59	2.76	2.54	3.00	4.78	3.76	5.10	1.96	2.58
	GRmin (api)	-	30	30	30	30	35	35	35	35	35	35	35	35	35
	GRmax (api)	-	75	69	79	96	92	100	100	98	98	98	94	90	90
Sairi Matri	RHoma (g/cc)	-	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65
	DTma (us/ft)	-	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5
	Rw @25°C	-	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222
	Rw salinity (ppm)	-	27000	27000	27000	27000	27000	27000	27000	27000	27000	27000	27000	27000	27000

Table 3-6: Karish-1, reservoir properties for the high case, with PHIE and VCL cut offs of 8% and 60% respectively using the Sw derived from the saturation height function.

SAND UNIT	TOP DEPTH	BOTTOM DEPTH	GROSS INTERVAL	NET INTERVAL	VCL	PHIE	SWE	INTERPRETATION
	mMDBR T	mMDBR T	m	m	%	%	%	
A Sand	4340.4	4335.3	14.9	11.7	46.9	13.8	40.8	Gas
B Sand	4405.2	4413.7	8.5	7.9	31.5	18.7	29.7	Gas
	4448.1	4450.8	2.6	2.1	18.8	19.6	28.4	Gas
C Sand	4460.3	4544.0	83.7	56.2	19.0	19.3	36.3	Gas
	4544.0	4596.4	52.4	21.0	27.8	15.0	97.2	Water
D Sand	4613.6	4703.1	89.5	61.9	21.7	17.0	96.6	Water

Table 3-7: Karish-1, reservoir properties for the reference case, with PHIE and VCL cut offs of 9% and 50% respectively using the Sw derived from the saturation height function.

SAND UNIT	TOP DEPTH	BOTTOM DEPTH	GROSS INTERVAL	NET INTERVAL	VCL	PHIE	SWE	INTERPRETATION
	mMDBR T	mMDBRT	m	m	%	%	%	
A Sand	4340.4	4335.3	14.9	6.7	41.5	15.1	36.8	Gas
B Sand	4405.2	4413.7	8.5	6.9	28.6	19.5	28.5	Gas
	4448.1	4450.78	2.6	2.0	14.5	21.2	26.3	Gas
C Sand	4460.3	4544.0	83.7	55.4	17.5	19.8	35.7	Gas
	4544.0	4596.4	52.4	17.5	25.4	16.0	97.1	Water
D Sand	4613.6	4703.1	89.5	56.4	18.9	17.6	96.4	Water

Table 3-8: Karish-1, reservoir properties for the low case with PHIE and VCL cut offs of 10% and 40% respectively using the Sw derived from the saturation height function.

SAND UNIT	TOP DEPTH	BOTTOM DEPTH	GROSS INTERVAL	NET INTERVAL	VCL	PHIE	SWE	INTERPRETATION
	mMDBR T	mMDBR T	m	m	%	%	%	
A Sand	4340.4	4335.3	14.9	2.4	35.0	16.8	33.0	Gas
B Sand	4405.2	4413.7	8.5	5.2	23.3	21.3	26.1	Gas
	4448.1	4450.78	2.6	1.8	11.6	22.1	25.2	Gas
C Sand	4460.3	4544.0	83.7	54.3	16.2	20.2	34.9	Gas
	4544.0	4596.4	52.4	14.9	22.5	16.6	97.0	Water
D Sand	4613.6	4703.1	89.5	50.7	16.6	18.4	96.2	Water

Table 3-9: Karish-1, net pay calculation based on the image log analysis

SAND UNIT	DEPTH INTERVAL	FACIES 1	FACIES 2	FACIES 3	TOTAL NET PAY
	mMDBRT	m	m	m	m
A Sand	4436.9-4404.8	5.0	3.2	0.3	8.5
B Sand	4404.8-4458.8	3.7	2.4	4.3	10.4
C Sand	4458.8-4535.0	5.6	1.4	50.0	57.0
FACIES NO.	FACIES NAME	PAY CLASSIFICATION			
0	Shale	Non-Pay			
1	Shaly-sand	Pay			
2	Laminated Sand	Pay			
3	Good quality sand	Pay			

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3.6 Tanin-1: Petrophysical Analysis Results

3.6.1 Available Data

3.6.1.1 Wireline Logging

Wireline logging was carried out by Baker Hughes Atlas down to the total depth of 5528 mMDRT as summarised in Table 3-10.

3.6.1.2 MWD/LWD Logs

LWD logs were acquired by Baker Hughes INTEQ and summarised in Table 3-11.

3.6.1.3 Conventional Cores/Sidewall Cores

A total of 50 PSWC (Percussion Sidewall Core) were attempted over the interval of 5029-5391 mMDRT, with 28 considered to be good samples and 22 barrels were lost due to broken cables, resulting in 56% recovery.

3.6.1.4 Formation Testing

A total of 40 pressure test points were attempted using the RCI over the interval of 5040-5477 mMDRT, which resulted in 27 good tests, 10 were tight and 3 were aborted. During the run, a total of 9 formation fluid samples were recovered at three different depths and details of the fluid samples are summarised in Table 3-12.

3.6.1.5 Hole Condition

The hole and casing details are summarised in Table 3-13.

The logging measurements, in particular density log, were affected by poor hole condition over several intervals, particularly in claystones within the Late to Middle Miocene section due to hole washouts. Despite these conditions, the log responses are generally valid and did not affect the reliability of the petrophysical analysis. In porous sandstone intervals, the mud cake was well developed, resulting in a smaller hole diameter and good log responses.

The drilling mud parameters are given in Table 3-15.

The shale parameters were obtained from various cross plot techniques. The input parameters used in the interpretation are presented in Table 3-14.

3.6.2 Temperature

An extrapolated bottom hole temperature of 92.8°C was calculated at 5519.5 mMDRT using maximum temperature measured during wireline logging runs. Assuming a seabed temperature of 15.0oC, the geothermal gradient in the Tanin-1 well is 2.09°C/100 m.

3.6.3 Water Salinity

The formation water salinity in the Tanin-1 well was primarily determined from logs using the Pickett plot analysis, derived from known brine sandstone intervals, and compared to the formation water salinity derived in nearby well.

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A Pickett plot over the interval of 5170.0-5312.7 mMDRT within the C Sand (Figure 3-18), indicates that the formation water resistivity, R_w is 0.222 Ωm at 25.0°C, which equates to a formation water salinity of 27,000ppm NaCl equivalent. This value has resulted in close to 100% water saturation in clean water-bearing sandstones.

This formation water salinity is consistent with the formation water salinity used in the Karish-1 well.

3.6.4 Discussion of Results

A summary of the reservoir intervals is presented in Table 3-17 which is based on the “most-likely case” (using the S_w derived from resistivity log) and will be discussed further in this section.

3.6.4.1 A Sand

The sandstone in this unit is generally described as clear to translucent, unconsolidated, with fine to medium grains and occasional coarse grains. The grains are well to moderately sorted, sub angular to sub rounded, occasionally rounded and contains minor mica, trace organic material and pyrite.

A total of 16.8 m net gas sandstone is interpreted over the interval of 5038.5-5058.2 mMDRT, with an average porosity of 17.4% and average water saturation of 32.3% (Figure 3-19). The presence of gas is confirmed by recovery of RCI sample at 5048.5 mMDRT, which contained gas.

As the sidewall core samples were highly fractured and damaged by the percussion sidewall coring process, the cores gave very optimistic porosity values when compared to the log-derived porosities.

3.6.4.2 B Sand

Sandstones in this unit is generally described as clear to translucent, unconsolidated, consisting of fine to medium grains, with occasional coarse grains. The grains are well to moderately sorted, sub angular to sub rounded, occasionally rounded and contain traces of forams, mica, organic material and heavy minerals.

A total of 13.9 m net gas sandstone is interpreted over the interval of 5096.1-5114.8 mMDRT, with an average porosity of 17.1% and average water saturation of 62.9% (Figure 3-20). The presence of gas is confirmed by recovery of the RCI gas sample at 5114.0 mMDRT and also a gas peak observed over this sandstone interval.

As the core samples were highly fractured and damaged by the percussion sidewall coring process, the cores gave very optimistic porosity values compared to the log-derived porosities.

3.6.4.3 C Sand

Sandstone in this unit was generally described as clear to translucent, unconsolidated, consisting of fine to medium grains, loose grains, with occasional coarse grains. The grains are well to moderately sorted, sub angular to sub rounded, occasionally rounded and the sands contain traces of forams.

No significant hydrocarbon zones were interpreted in this sand unit and all reservoirs are essentially water saturated, with very minor gas saturations.

A total of 84.8 m net water-bearing sandstone is interpreted over the interval of 5165.3-5302.9 mMDRT, with an average porosity of 16.4% (Figure 3-21). One RCI water sample was recovered at 5246.8 mMDRT.

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3.6.4.4 D Sand

Sandstone in this unit was generally described as clear to translucent with very light grey in colour, unconsolidated, consists of fine to medium grains, with occasional coarse grains. The grains are well to moderately sorted, sub angular to sub-rounded with occasionally rounded grains.

No significant hydrocarbon zones were interpreted in this sand unit and all reservoirs are essentially water saturated, with very minor gas saturations.

The upper section of this unit consists of 10.4 m net sandstone, which is interpreted to be essentially water saturated. This sandstone has an average porosity of 15.6%, with 88.5% average water saturation (Figure 3-22).

Sandstone over the interval of 5165.3-5302.9 mMDRT is interpreted as water-bearing sandstone with a total net reservoir of 84.8 m.

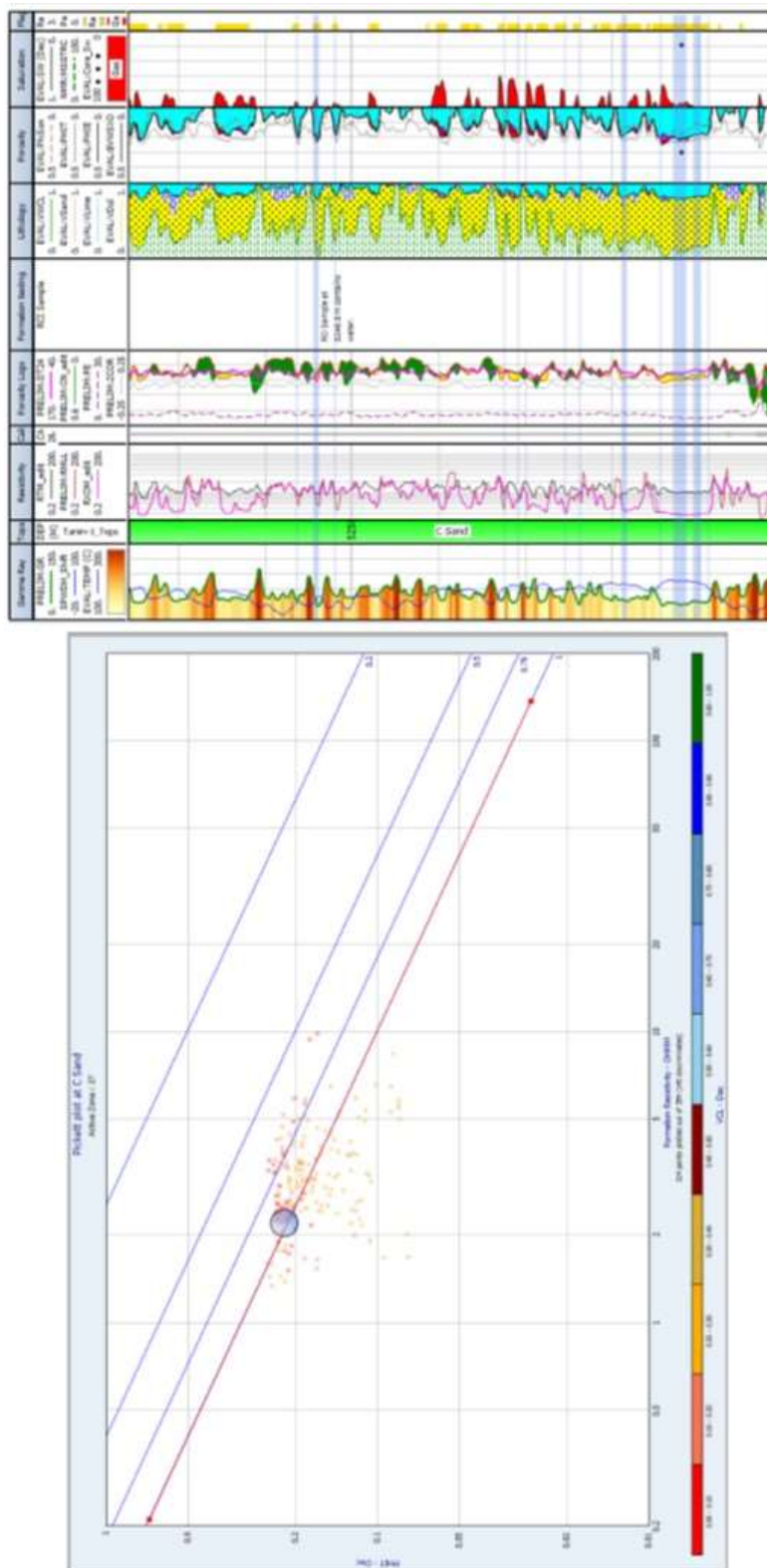
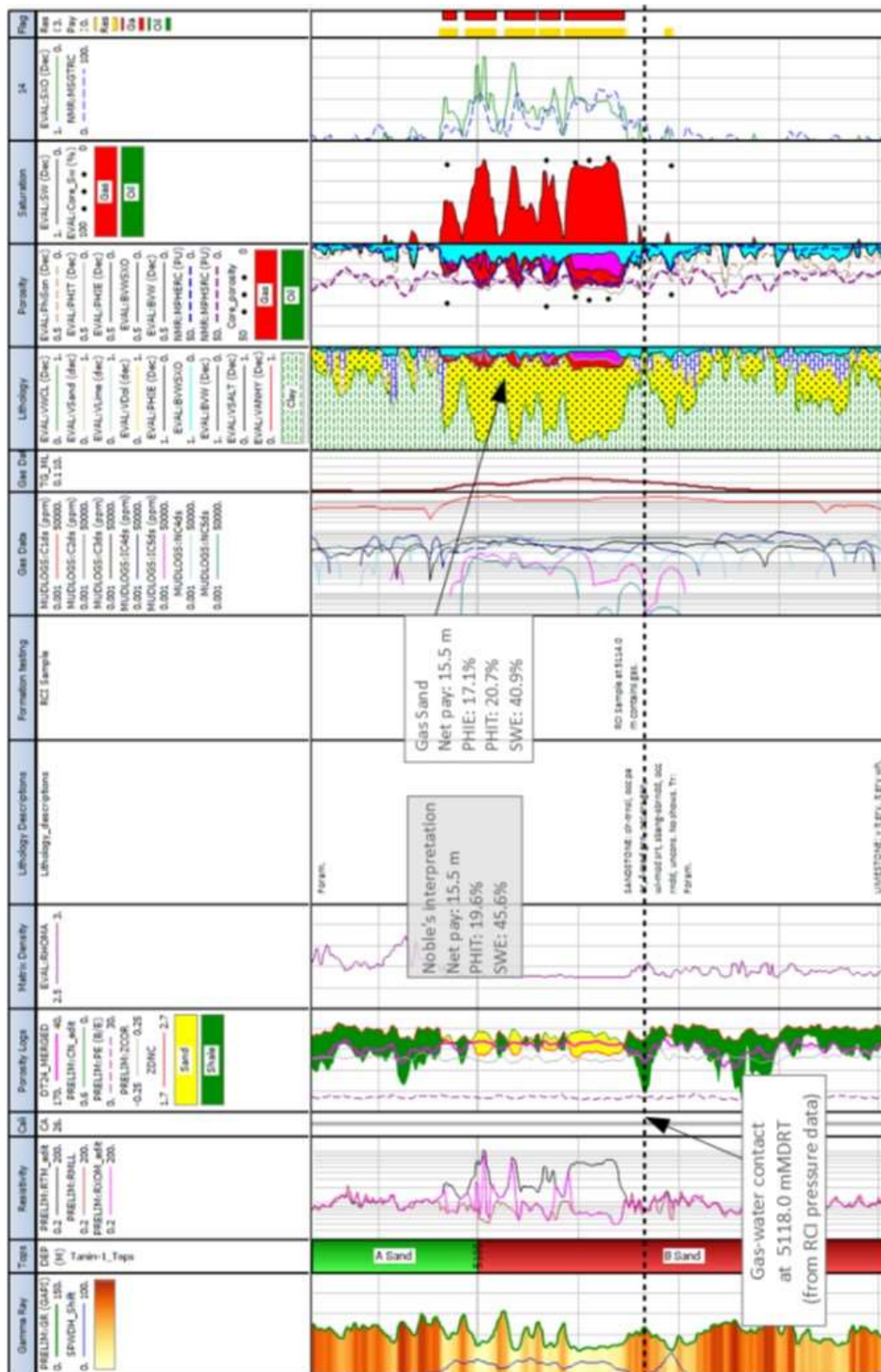


Figure 3-18 Tanin-1, the Pickett plot over the C Sand Unit

Figure Note: Indicates an R_w of 0.222 ohm-m@25°C, which equates to a formation water salinity of 27,000 ppm NaCl equivalent.





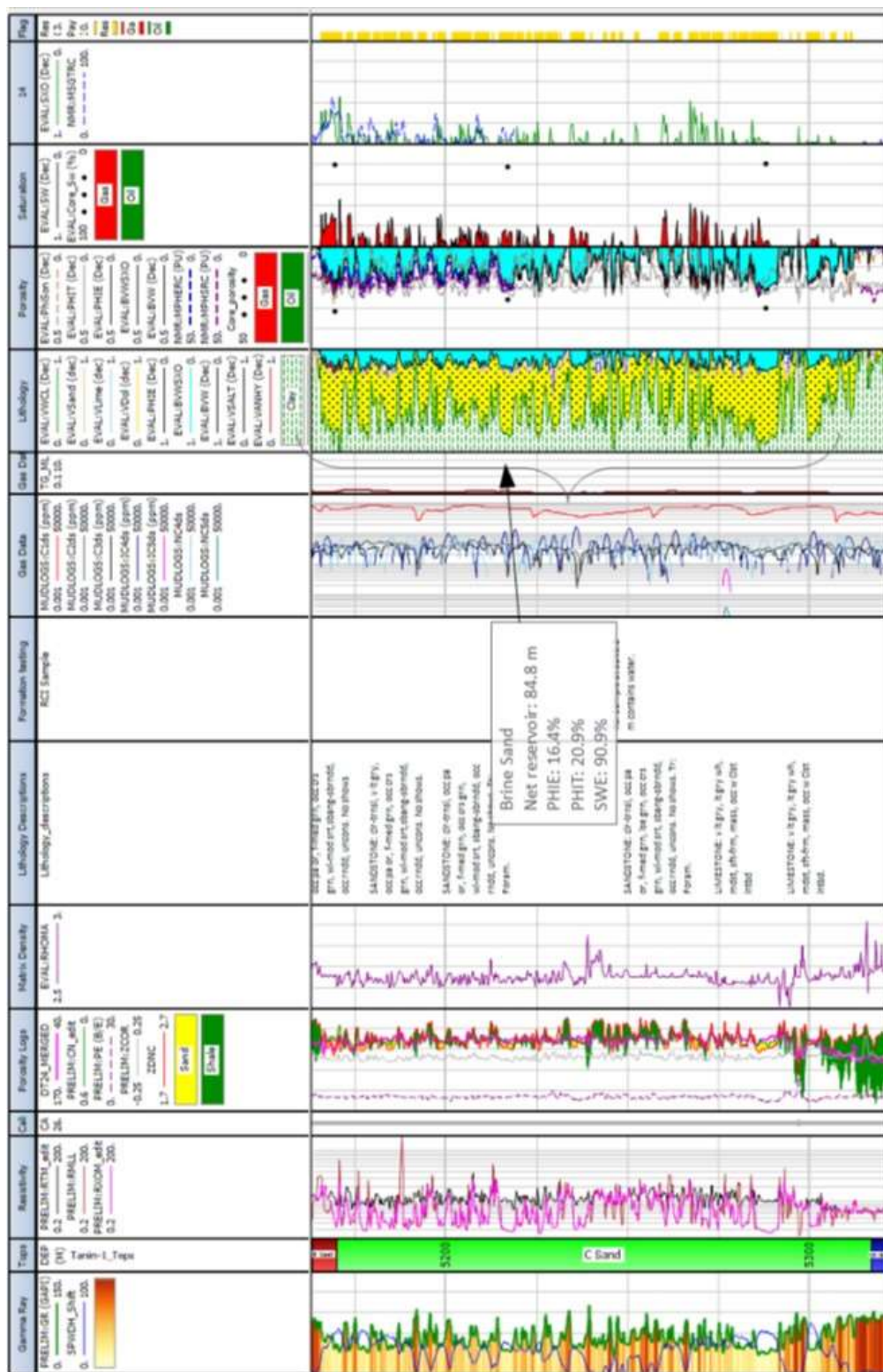
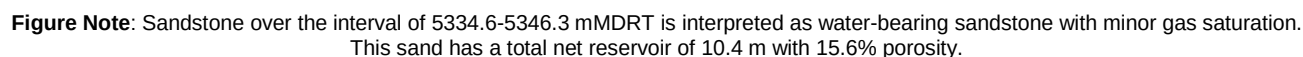


Figure 3-21 Tanin-1, interpreted section of the C Sand Unit.

Figure Note: Sandstone over the interval of 5165.3-5302.9 mMDRT is interpreted as water-bearing sandstone with a total net reservoir of 84.8 m.



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3.6.4.5 Comparison between various porosity methods (Density, Neutron-Density and Sonic porosities)

Porosity has been calculated over the gas sandstones in the A and B Sand Units using the density, neutron density and sonic logs to assess the uncertainties of different porosity methods. Based on the interpreted section shown in Figure 3-23, sonic porosity has a slightly lower porosity compared to density and neutron density porosities. This may be due to the presence of unconnected pores in the sandstone. Whereas the density and neutron-density porosities are relatively similar. The density porosity is preferable in this zone as it has good agreement with the NMR porosity.

3.6.4.6 Comparison between well log interpretation to NMR results calibration

As the NMR logging tool has a relatively shallow depth of investigation, the tool readings can be affected by fluid invasion and borehole conditions in permeable zones. In general, the NMR result curves give a good match with the well log-derived interpretation curves (Figure 3-24)

3.6.4.7 Sensitivity Analysis

PHIE and VCL cut offs. For the high case, PHIE and VCL cut offs of 8% and 60% respectively has been used and results are presented in Table 3-16. Whereas, for the “most-likely” case, a PHIE cut off of 9% has been applied, with the VCL cut of has been set to 50% as presented in Table 3-17. For the low case, PHIE and VCL cut offs of 10% and 40% respectively has been applied and presented in Table 3-18.

3.6.5 Log Quality Review

The wireline logs acquired in this well are generally good quality, with minor intervals designated as “bad hole” and gaps, particularly on the density log.

As the recorded DTS log for Tanin-1 is only available from 3616.0-4618.8 mMDRT, the synthetic shear sonic was generated and used to extend the log down to 5500.9 mMDRT.

As the well was drilled with a water-based mud, sonic and density logs were highly affected by mud filtrate invasion over permeable zones. Therefore, invasion corrections are applied to these logs using Gassmann fluid substitution.

Figure 3-25 and Figure 3-26 show a comparison between the recorded and final elastic log data, corrected for “bad hole”, invasion, and synthetic data patching (where needed).

3.7 Integration of Petrophysical Results into Geological Model

The petrophysical analysis presented in Section 3 has been fully adopted and integrated into the geological modelling (Section 4), with the only exception being a slight change to the petrophysical cut-offs used in the reference case. Based on operator experience, the routine core analysis poroperm data (Section 4.5.2) and the fluid phase of the reservoir (gas), the porosity cut-off has been changed from PHIE>0.09 to PHIE>0.08. With this minor exception, the geological models are entirely consistent with the petrophysical analysis. It is important to note that the sums and averages presented in Section 3 (Table 3-7 and Table 3-17) differ from those presented later in Section 4 (Table 4-9), due to the former being sums and averages by fluid phase and the later by stratigraphic unit. It is also worthy of note that Table 3-7 and Table 3-17 show average net effective porosity, whereas Table 4-9 show average net total porosity, with total porosity being a prerequisite for the determination of the total reservoir pore volume.

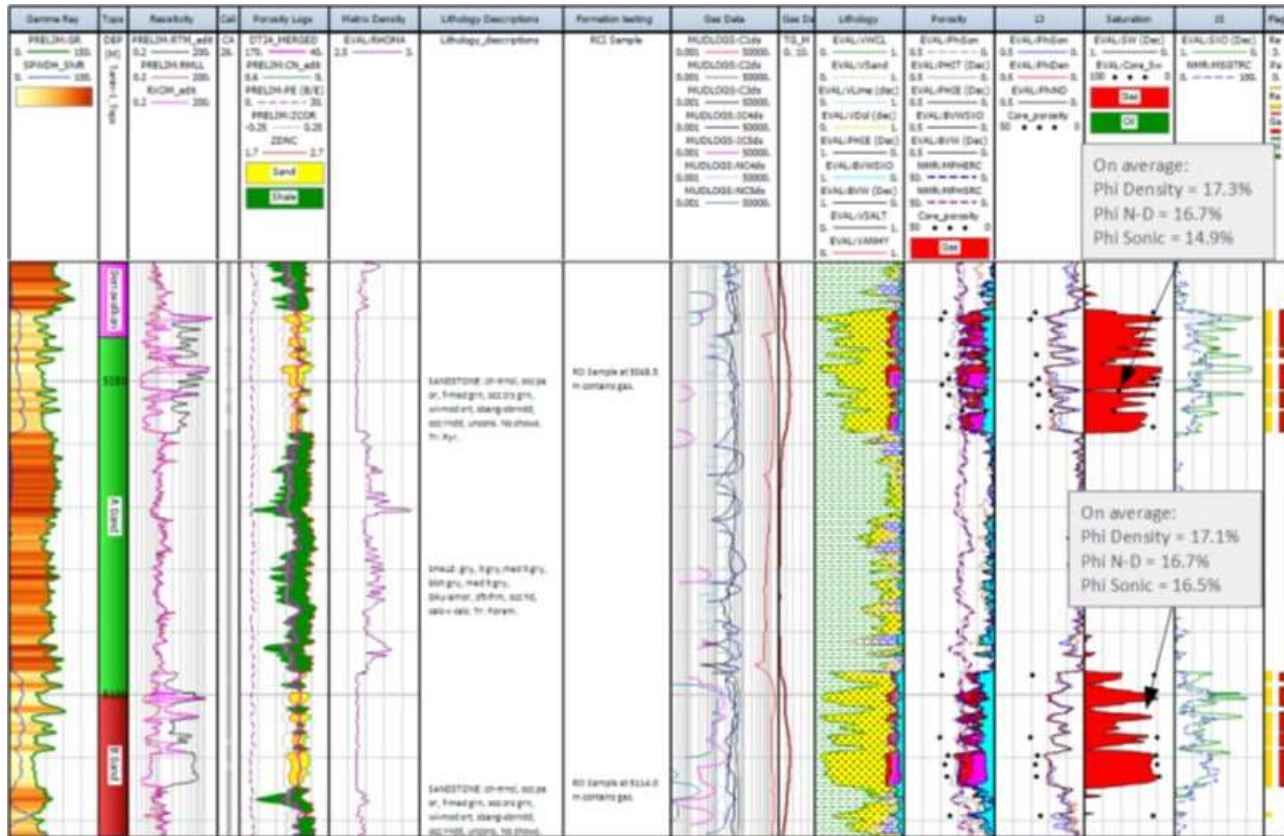


Figure 3-23 Tanin-1 comparison of various porosity methods.

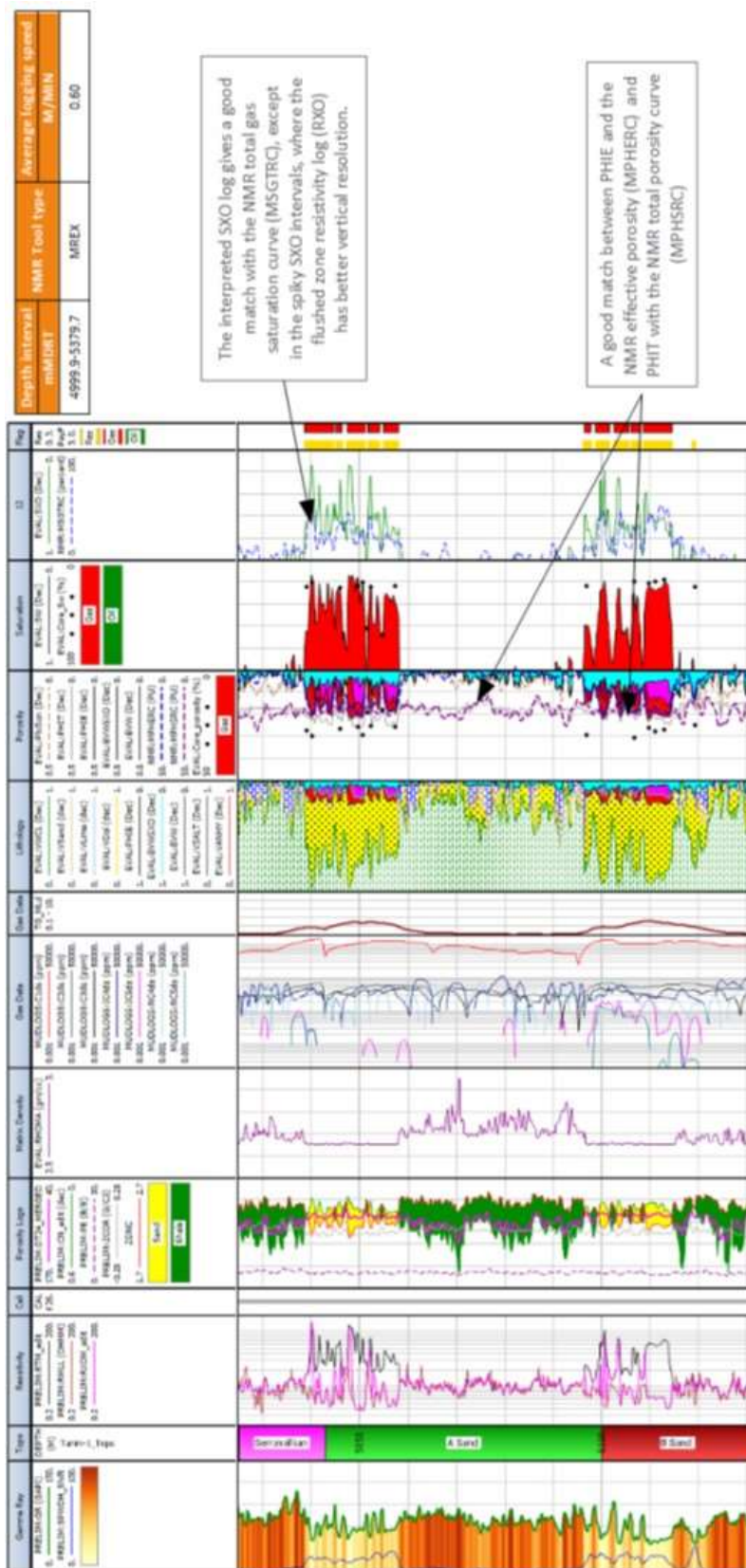


Figure 3-24 Tanin-1 well log interpretation to NMR results calibration.

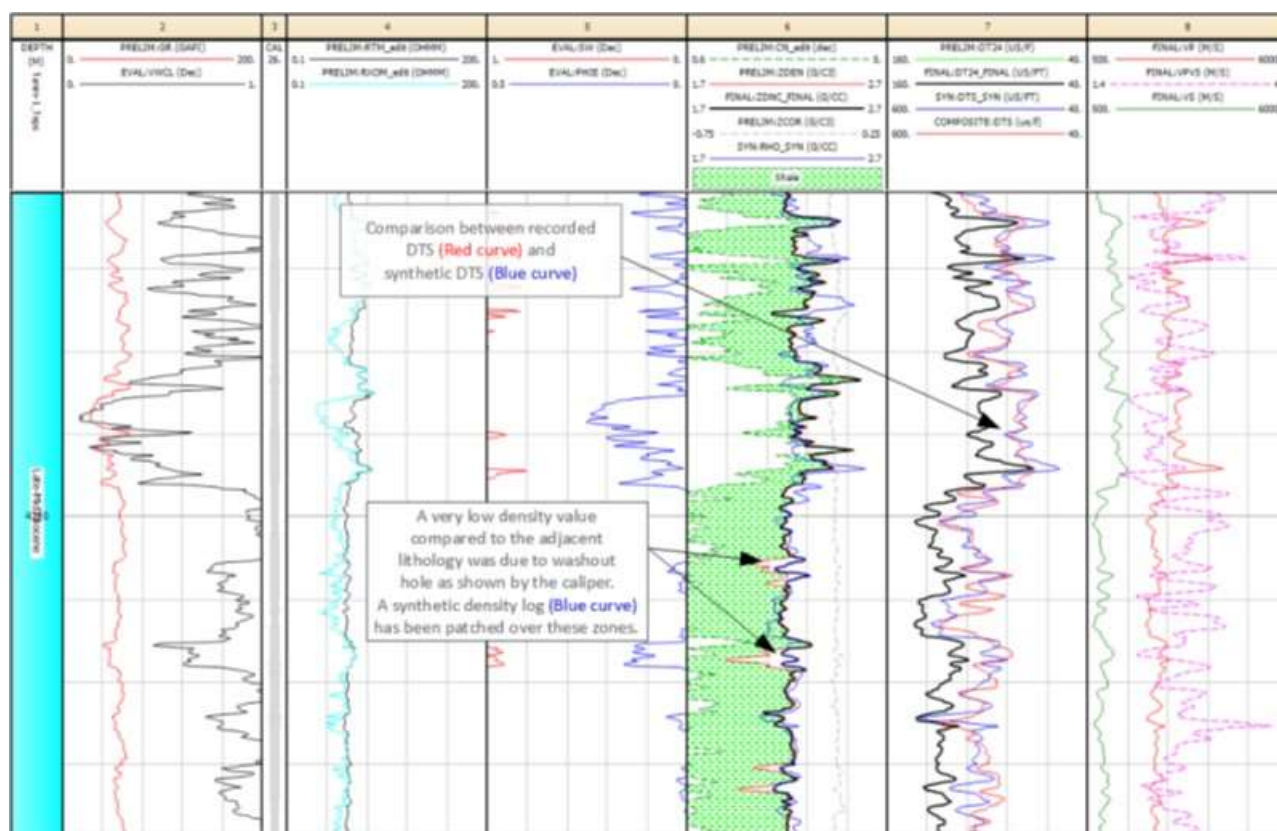


Figure 3-25 Tanin-1 composite plot of the Late to Mid Miocene section.

Figure Note: Comparison of the original and the final elastic logs.

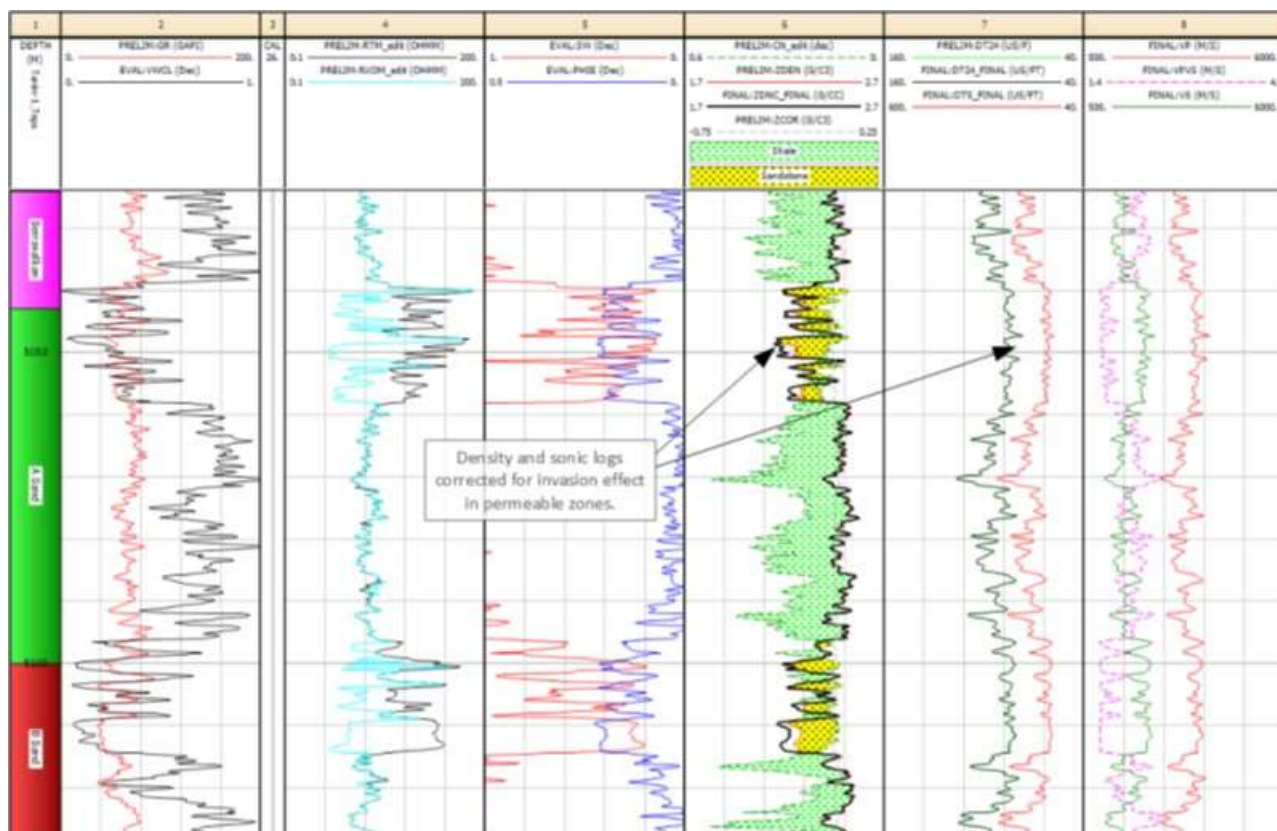


Figure 3-26 Tanin-1 composite plot of the A and B Sand sections.

Figure Note: Showing the final elastic logs corrected for invasion effect in permeable zones.

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Table 3-10: Tanin-1 wireline logging.

	DEPTH INTERVAL	HOLE SIZE	WIRELINE SUITE	MAX TEMPERATURE
	mMDBRT	(inch)		°F
1A	1868.4-2904.0	26	4 Arm Calliper	123.8
2A	3648.0-4633.0	12 1/4	TTRM-DSL-ORIT-XMAC-XFM1-WGI-RTEX- MLL-CN-ZDL-CAL	-
2B	Aborted (Weather)	13 5/8	VSP	
2C	2170.0-3648.0	8 1/2	SBT-CCL-GR	130
3A	4632.5-5519.0		TTRM-DSL-ORIT-XMAC-XFM1-WGI-RTEX- MLL-CN-ZDL-CAL	184.8
3B				
3C	4879.0-5477.0		RCI	190.2
3D	4626.0-5434.0		STAR/CBIL	199.4
3E	5000.0-5370.0		MREX	187.8
3F	3670.0-5365.0		VSP	-
3G				
3H	5029.0-5391.0		Percussion Cores	-
3I	3542.0-4634.0	9 5/8	SBT-CCL-GR	-
3J				

Table 3-11: Tanin-1 LWD operation

RUN NO.	LWD LOG RUNS	DEPTH INTERVAL
	mMDBRT	mMDBRT
1	DIR/GR/Resistivity/ECD	1868-2937
3	DIR/GR/Resistivity/ECD	2937-2940
3	DIR/GR/Resistivity/ECD	2940-3663
4	DIR/GR/Resistivity/ECD	3663-4482
5	DIR/GR/Resistivity/ECD	4482-4636
6	DIR/GR/Resistivity/ECD	4636-5528

Table 3-12: Tanin-1 RCI samples

DEPTH	FORMATION PRESSURE	FORMATION TEMP	FLUID PROPERTY
mMDBRT	psia	°F	
5048.5	8693	173.6	Gas
5114.0	8717	173.1	Gas
5246.8	8903	180.2	Water

[illegible]

Table 3-16: Tanin-1 reservoir properties for the high case, with PHIE and VCL cut offs of 8% and 60% respectively using the Sw derived from the saturation height function

SAND UNIT	TOP DEPTH	BOTTOM DEPTH	GROSS INTERVAL	NET INTERVAL	VCL	PHIE	SWE	INTERPRETATION
	mMDBRT	mMDBRT	m	m	%	%	%	
A Sand	5038.5	5058.2	19.7	17.4	27.7	17.2	32.6	Gas
B Sand	5096.1	5114.8	18.8	14.0	24.4	16.5	64.3	Gas
C Sand	5165.3	5302.9	94.6	94.6	28.1	15.8	91.3	Water
D Sand	5334.6	5346.3	11.7	10.7	13.1	15.4	88.5	Water minor gas
	5353.1	5480.8	127.7	62.0	33.9	14.4	96.2	Water

Table 3-17: Tanin-1 reservoir properties for the reference case with PHIE and VCL cut offs of 9% and 50% respectively using the Sw derived from the saturation height function.

SAND UNIT	TOP DEPTH	BOTTOM DEPTH	GROSS INTERVAL	NET INTERVAL	VCL	PHIE	SWE	INTERPRETATION
	mMDBRT	mMDBRT	m	m	%	%	%	
A Sand	5038.5	5058.2	19.7	17.1	27.4	17.4	32.3	Gas
B Sand	5096.1	5114.8	18.8	13.9	22.1	17.1	62.9	Gas
C Sand	5165.3	5302.9	94.6	84.8	25.6	16.4	90.9	Water
D Sand	5334.6	5346.3	11.7	10.4	12.8	15.6	88.5	Water minor gas
	5353.1	5480.8	127.7	52.0	30.2	15.3	96.1	Water

Table 3-18: Tanin-1 reservoir properties for the low case, with PHIE and VCL cut offs of 10% and 40% respectively using the Sw derived from the saturation height function.

SAND UNIT	TOP DEPTH	BOTTOM DEPTH	GROSS INTERVAL	NET INTERVAL	VCL	PHIE	SWE	INTERPRETATION
	mMDBRT	mMDBRT	m	m	%	%	%	
A Sand	5038.5	5058.2	19.7	15.1	25.4	18.0	31.1	Gas
B Sand	5096.1	5114.8	18.8	13.3	19.7	17.7	61.4	Gas
C Sand	5165.3	5302.9	94.6	73.1	22.8	17.2	91.1	Water
D Sand	5334.6	5346.3	11.7	9.9	12.2	15.9	88.5	Water minor gas
	5353.1	5480.8	127.7	39.3	25.9	16.4	95.8	Water

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3.8 Section references

REFERENCE NUMBER	REFERENCE TITLE
[1]	Batzle, M. and Wang, Z., 1992, Seismic properties of pore fluids: Geophysics, Soc. of Expl. Geophys., 57, 1396-1408 Christensen, C.J., Powers, G., M.S.C., Noble Energy, Inc., 2013, Formation Evaluation Challenges in Tamar Field, Offshore Israel: SPWLA 54th Annual Logging Symposium.
[2]	Cuddy, E., Allinson, G., Steele, R., 1993, A Simple, Convincing Model For Calculating Water Saturations In Southern North Sea Gas Fields: SPWLA 34th Annual Logging Symposium
[3]	Elshahawi, H., Fathy, K., Hiekal, S., 1999, Capillary Pressure and Rock Wettability Effects on Wireline Formation Tester Measurements: SPE Annual Technical Conference and Exhibition.
[4]	Harrison, B., Jing, X.D., 2001, Saturation Height Methods and Their Impact on Volumetric Hydrocarbon in Place Estimates: SPE Annual Technical Conference and Exhibition.

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4 Geological Model

4.1 Approach and key uncertainties

A deterministic workflow has been generated in Petrel 2016.2 from which a suite of geological models has been generated for Karish and Tanin. Reference case variables have subsequently been used in the workflow to generate a 'Best Technical Case' deterministic geological model for both the Karish and Tanin Complexes, which are summarised in this Section.

The objective of the deterministic geological modelling study was to generate static models that, 1) describe the geology of the Karish and Tanin fields, 2) capture the best technical assessment of the Gas Initially in Place (GIIP) and 3) result in an orthogonal grid capable of being simulated for the purpose of well optimisation, forecasting and profile generation.

The range of uncertainty in the static geological parameters has been captured in a probabilistic workflow, with a range of GIIP values output (Section 5.2.4) to address the geological uncertainty.

4.2 Input Data

4.2.1 Well Data

The Karish area of interest (AOI) includes only the discovery well, Karish-1 (Figure 4-1), with the Tanin AOI including only the Tanin-1 discovery well (Figure 4-2). Offset wells in the Tamar and Leviathan developments would be very beneficial for constraining the geological model, in particular the range of uncertainty, due their immediate relevance to the Karish and Tanin reservoirs. This data has not been made available to Energean.

Regional well data, namely Myra-1 and Aphrodite-2, which were purchased as part of the 1st Israel Offshore Round data package from the Ministry of National Infrastructures, Energy and Water Resources, have not been explicitly used in either the Tanin or Karish geological model owing to the large lateral offset distances making any resulting geological grid unmanageable. Observations and interpretations from these wells have however, been included in the conceptual model and most significantly in the Operator's assumptions for the aquifer strength (Section 4.3.5.2).

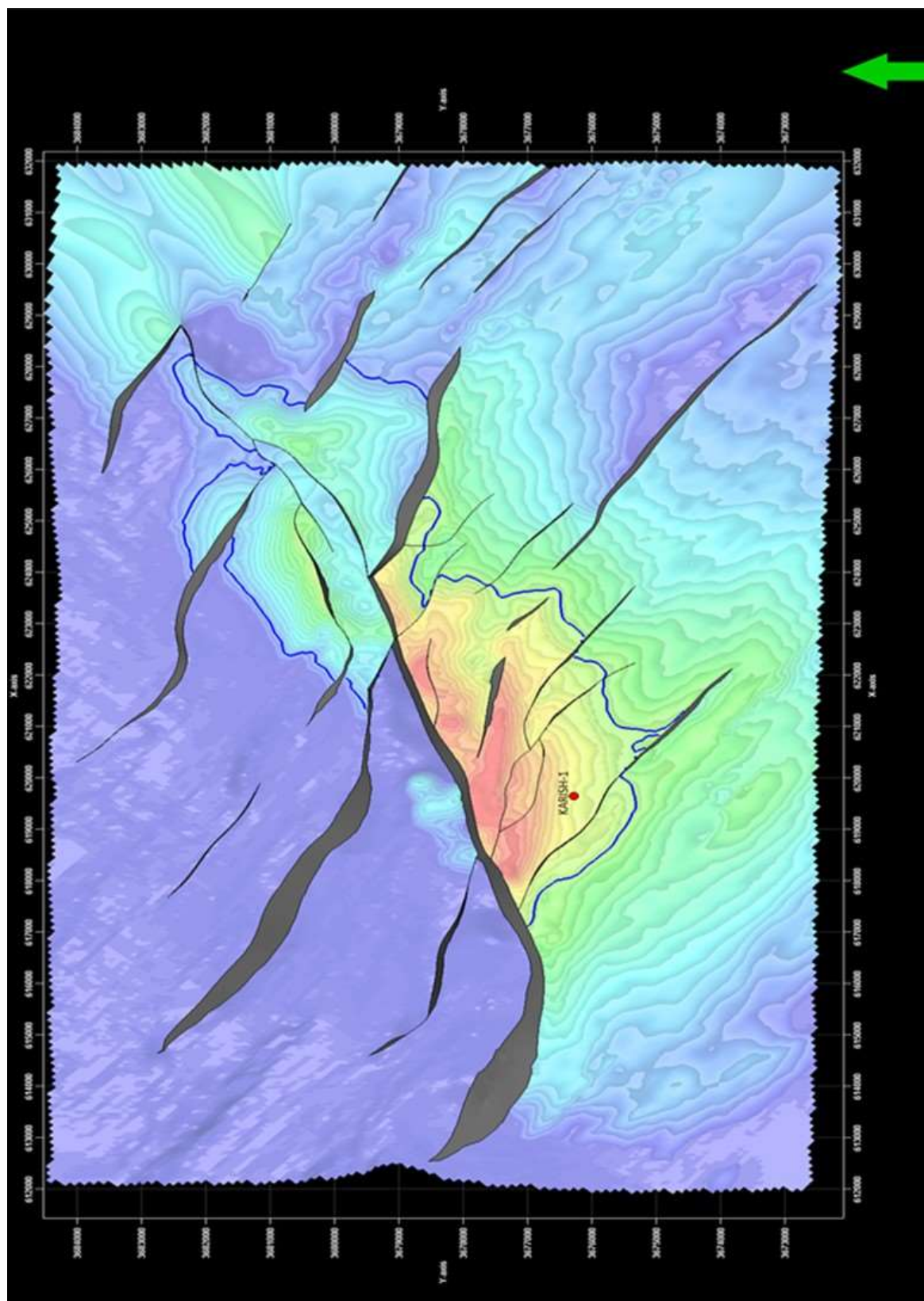


Figure 4-1 Geographic location of Karish-1 used in the Karish geological model

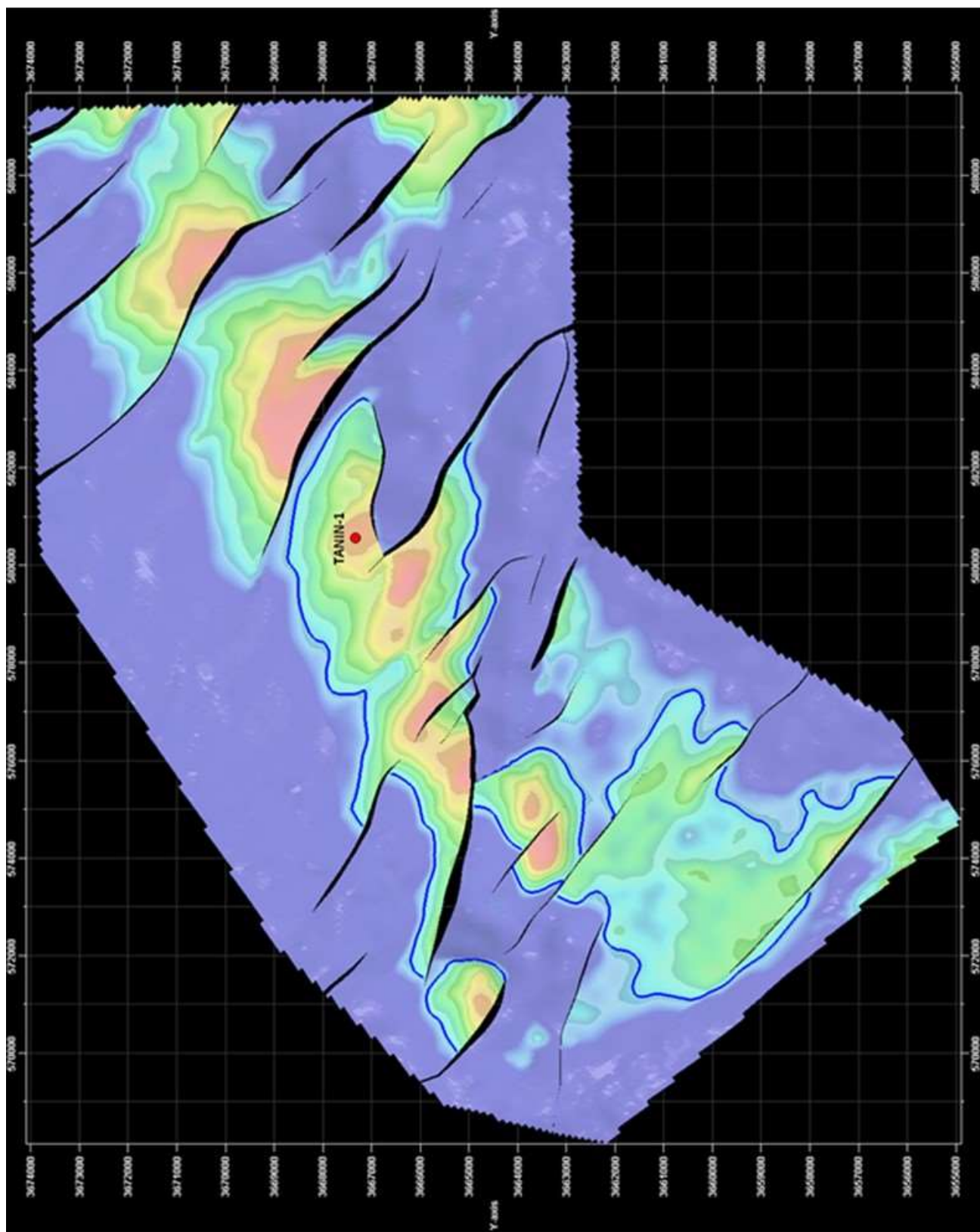


Figure 4-2 Geographic location of Tanin-1 used in the Tanin geological model

4.2.2 Formation Tops

For the purpose of constructing a geological model for the Karish and Tanin fields, a comprehensive set of Early Miocene formation tops has been interpreted for Karish-1 and Tanin-1. Conventional correlation based on the available well logs suites has been carried out, using the sparse biostratigraphic data (Ragan Biostrat, 2013) to constrain the interpretation.

A further QC of the formation tops was made by way of a de-sanding method. A Vshale (Locke, 2017) cut-off of <0.5 was applied to remove the sand component from the Vshale curve. The Vshale curve is then condensed and an interpretation of the main regional pelagic background deposition is performed. In this way the variable (clastic) component is removed from the well log response, resulting in a high confidence correlation.

Both the conventional and de-sanding techniques were in very good agreement, resulting in a high confidence set of formation tops (Table 4-1) which have been used to constrain the geological models for both Tanin and Karish.

The resulting correlation is shown in (Figure 4-3).

Table 4-1: Karish & Tanin Formation Tops

WELL	FORMATION TOP	X	Y	TVDSS(M)	MDBRT(M)
KARISH_01	Top A Sand Equivalent	619645.0	3676247.4	-4327.0	4350.9
KARISH_01	Top A Sand Preserved	619645.0	3676247.4	-4343.0	4366.9
KARISH_01	Top AB Shale	619645.0	3676247.4	-4343.0	4366.9
KARISH_01	Top B Sand	619645.0	3676247.4	-4382.0	4405.6
KARISH_01	Top C Sand	619645.0	3676247.4	-4436.0	4460.5
KARISH_01	C Lower	619645.0	3676247.4	-4488.0	4511.6
KARISH_01	Top CD Shale	619645.0	3676247.4	-4573.0	4597.2
KARISH_01	Top D Sand	619645.0	3676247.4	-4590.0	4614.0
KARISH_01	Top D2 Interval	619645.0	3676247.4	-4621.0	4645.2
KARISH_01	Top D3 Interval	619645.0	3676247.4	-4662.0	4685.7
KARISH_01	Base D3 Sand	619645.0	3676247.4	-4688.0	4712.2
KARISH_01	Top D3.5	619645.0	3676247.4	-4710.0	4733.8
KARISH_01	Top D4 Interval	619645.0	3676247.4	-4741.0	4765.2
TANIN_01	Top A Sand Equivalent	580492.0	3667291.9	-5015.0	5038.8
TANIN_01	Top A Sand Preserved	580492.0	3667291.9	-5015.0	5038.8
TANIN_01	Top AB Shale	580492.0	3667291.9	-5033.0	5057.1
TANIN_01	Top B Sand	580492.0	3667291.9	-5072.0	5095.6
TANIN_01	Top C Sand	580492.0	3667291.9	-5142.0	5166.5
TANIN_01	Top CD Shale	580492.0	3667291.9	-5287.0	5310.9
TANIN_01	Top D Sand	580492.0	3667291.9	-5310.0	5333.9
TANIN_01	Top D2 Interval	580492.0	3667291.9	-5330.0	5353.6
TANIN_01	Top D3 Interval	580492.0	3667291.9	-5378.0	5402.0
TANIN_01	Top D4 Interval	580492.0	3667291.9	-5445.0	5469.3



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4.3 Structural Model

4.3.1 Pillar Gridding

Grid boundaries have been defined to incorporate the discoveries and all prospects/leads at the Miocene level within the Karish (Figure 4-4) and Tanin (Figure 4-5) complexes. For the Karish complex this includes Karish Main (development), Karish North (prospect) and Karish East (lead). For the Tanin complex, this includes the Tanin discovery (Tanin A-C) and all of the Miocene prospectivity on the Tanin Lease (Tanin D-F).

The grid area for the Karish geological model is some 90.8km² and for the Tanin complex some 85.3km², with the skeleton grids being designed to sufficiently cater for all possible future activity on the respective Leases. Prior to dynamic simulation, both grids are cropped to the AOI with Karish (Figure 4-6) and Tanin (Figure 4-7) being reduced to 41.8km² and 71.8km² respectively.

Both grids have been built with an I/J grid dimension of 100m x 100m, with the grid dimension being dictated by the close convergence of faults, rather than the minimum geological body size. The grid has been rotated anticlockwise by 51° for Karish and 29° for Tanin to align the structural grid with the dominant fault orientations to create a more orthogonal grid.

The Karish grid incorporates 29 faults and Tanin, 61 faults. In all cases, the grid has been aligned with the faults, with none of the faults being stair-stepped. All faults have been modelled as linear or vertical to ensure an orthogonal grid. The Karish structural model consists of three segments (Figure 4-8), whilst Tanin has been modelled as single segment.

Both skeleton grids have been successfully created without any negative cell volumes in either the Karish or Tanin models, with both models being successfully initialized in the reservoir simulator (Section 6).

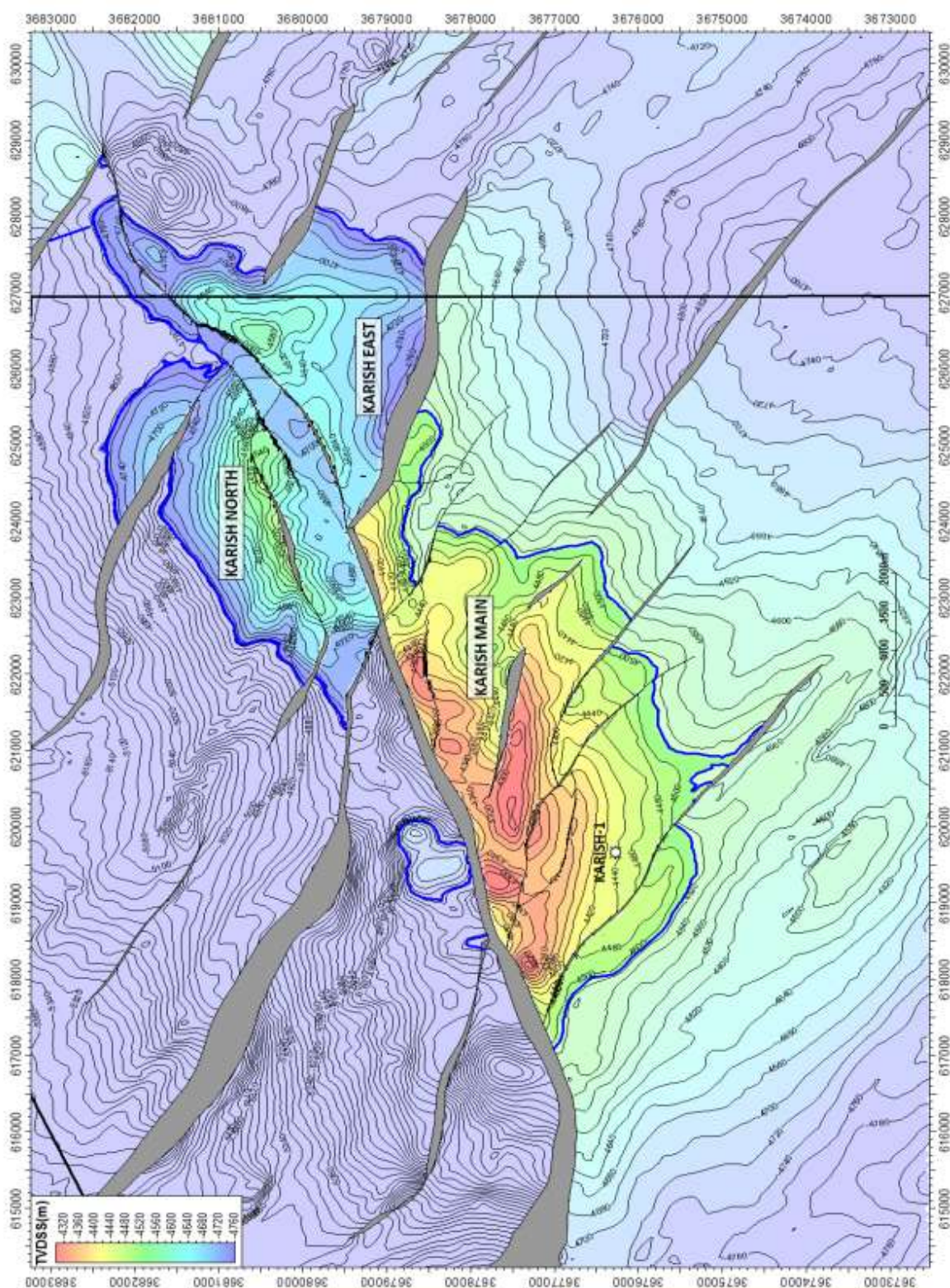


Figure 4-4 Karish Complex Top C Sand Depth Map (m)

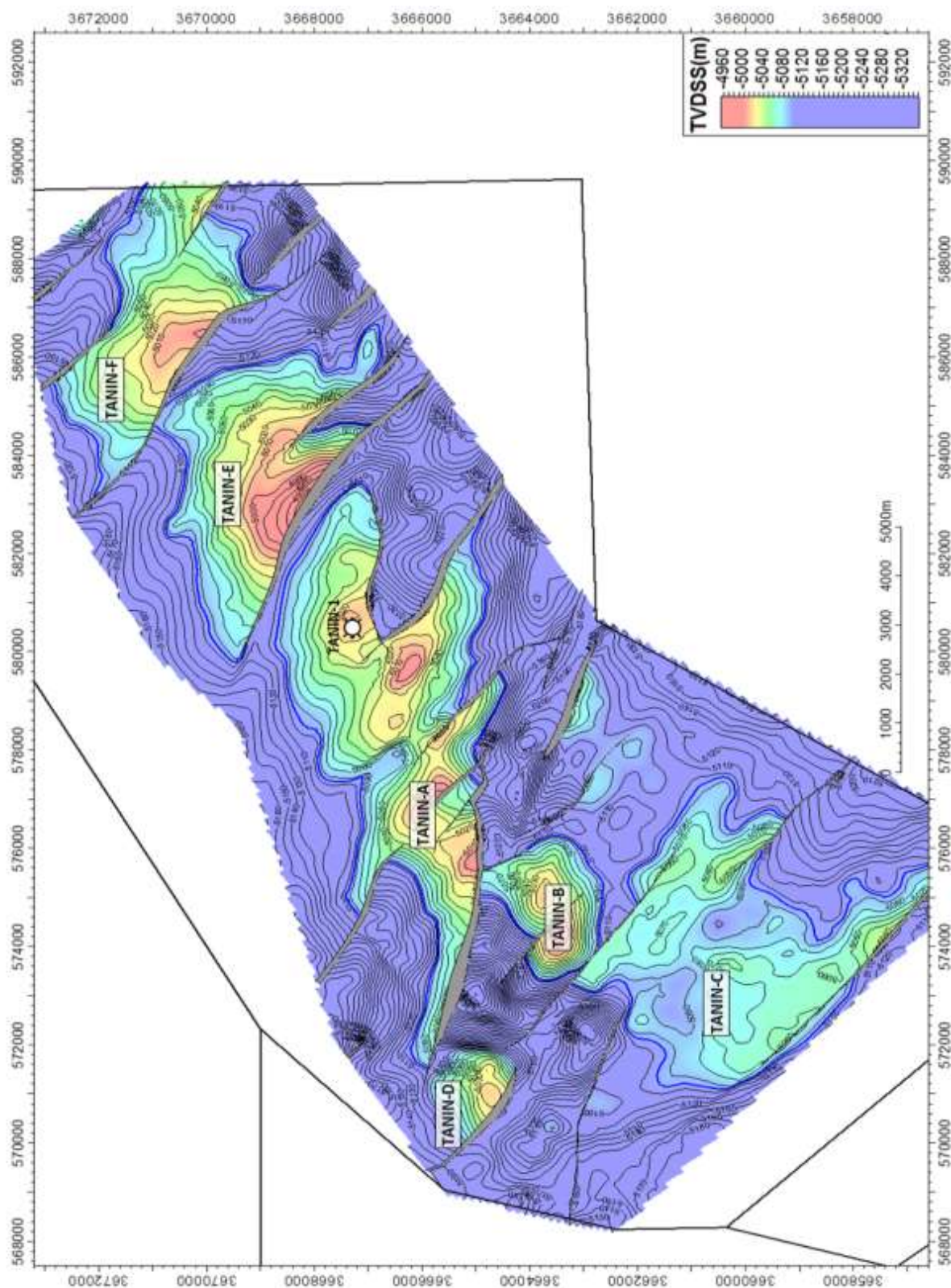


Figure 4-5 Tanin Complex Top A Sand Depth Map (m)

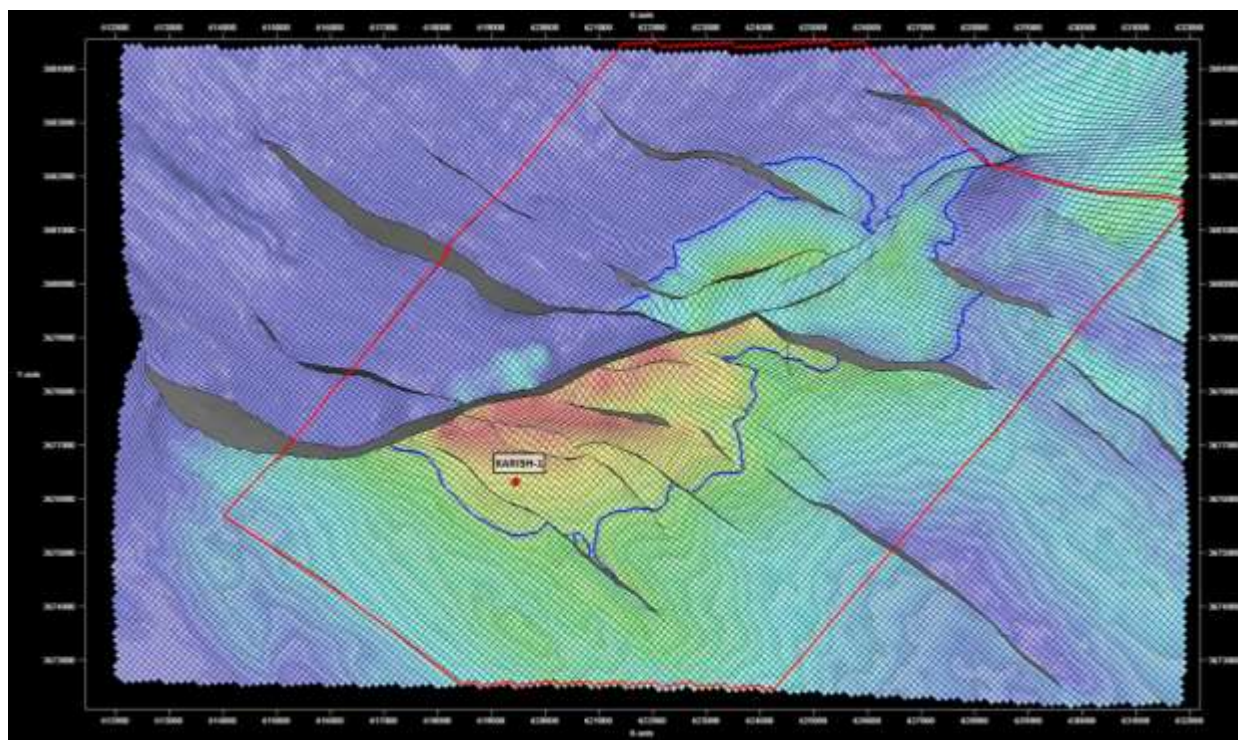


Figure 4-6 Karish Complex Simulation Model Extent

Figure Note: Shown by red polygon

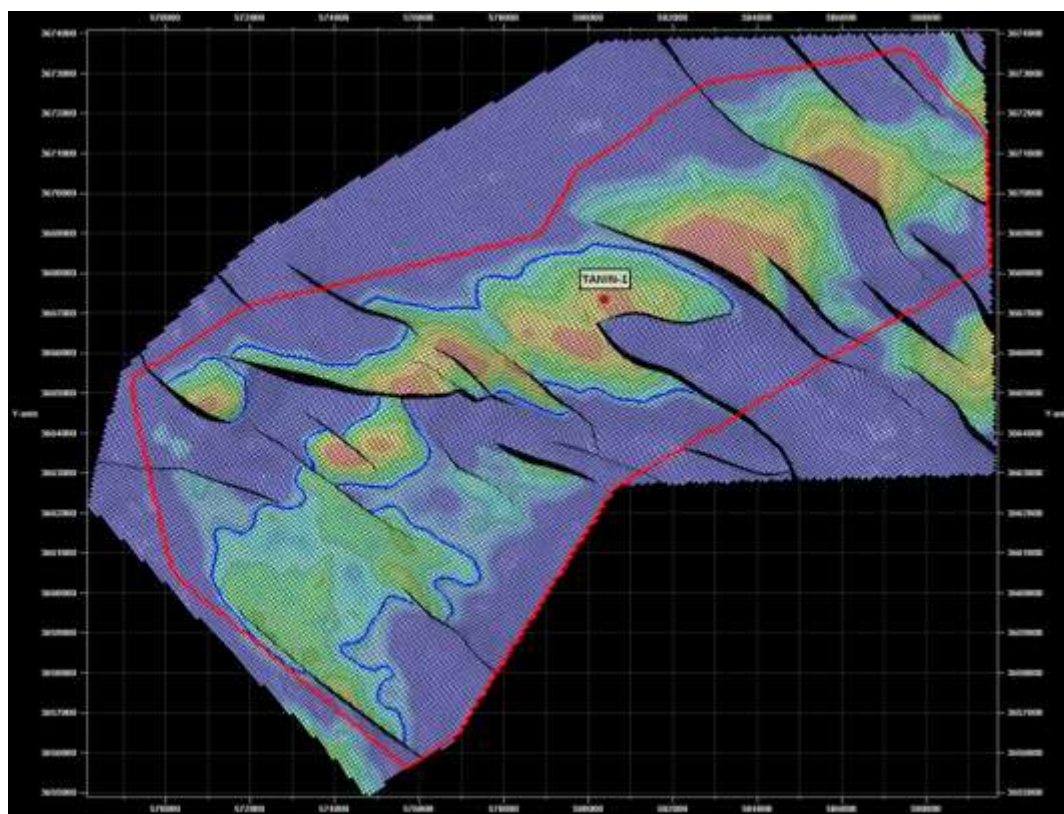


Figure 4-7 Tanin Complex Simulation Model extent

Figure Note: Shown by red polygon

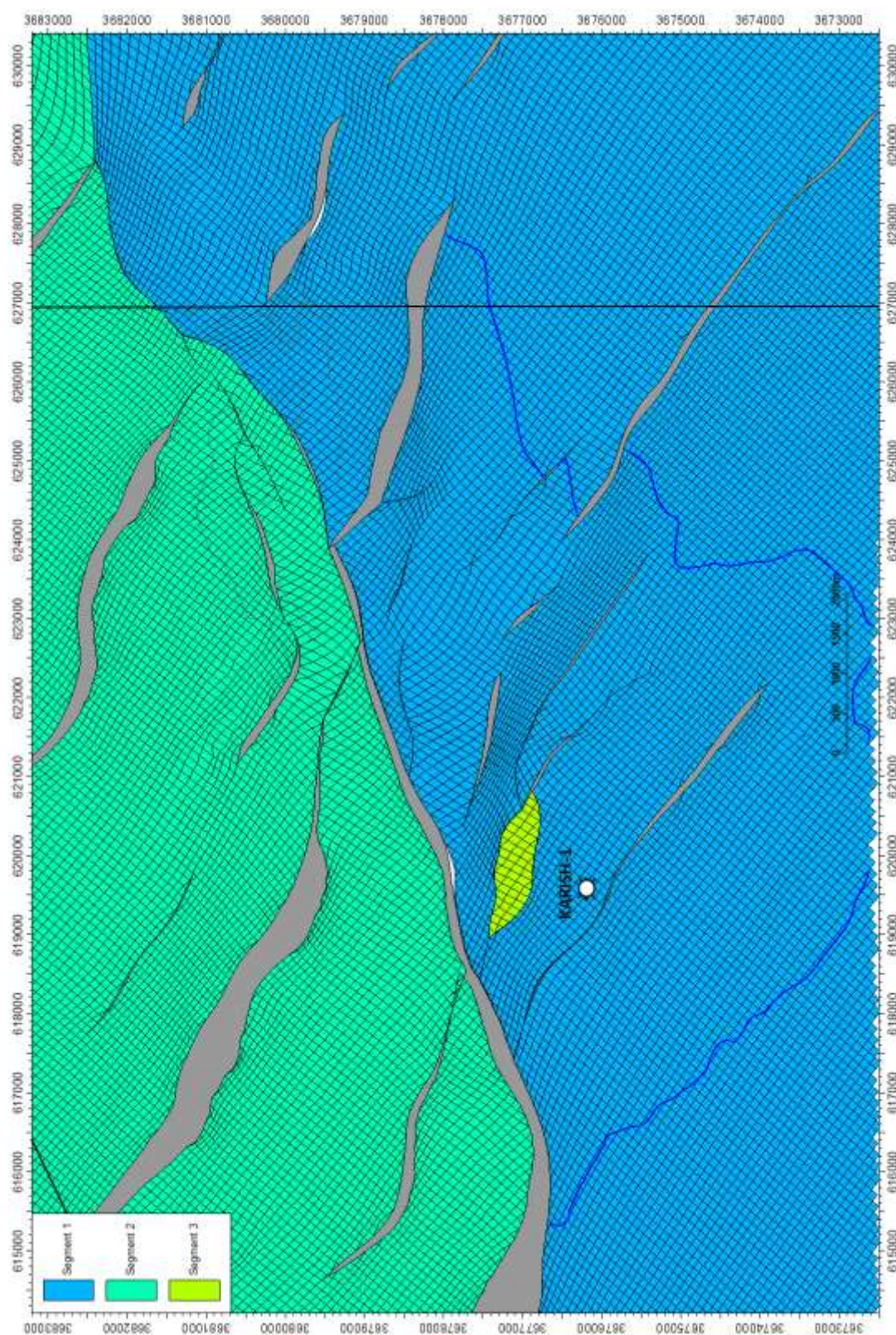


Figure 4-8 Karish Geological Model Structural Segments

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4.3.2 Horizon Modelling

4.3.2.1 Karish Complex

All seismically interpreted horizons have been used for the geological model, with 4 of the 5 interpreted, being explicitly modelled as Karish model horizons namely: Top B Sand, Top C Sand, Top D Sand and Top D3.5 Sand (intra-D sand reflector – see Section 2.46).

The Top A Sand has been indirectly used to generate a Top Reservoir (Tamar Sand) horizon. As discussed in Section 2.4.6, the Top Sand is an erosive surface with seismic scale incision being apparent, particularly on the crest of Karish Main. The correlation of Tanin-1 and Karish-1 also indicates an incision surface within the Karish-1 well (Figure 4-9). Rather than modelling the erosional truncation of the upper geological model layers within the A Sand, which is not conducive for successful reservoir model simulation, the uppermost reservoir model surface was generated using an isochore surface of 55m from Top B Sand, to generate a surface which is a 'restored' Top A surface with no incision. The 55m True Vertical Thickness is based on the A interval thickness from Tanin-1. The interpreted Top A interpreted surface (erosive) has then been captured by modelling the thickness between the restored and interpreted Top A erosive surface as a shale plug. In this way, the layering within the A sand interval has been modelled as conformable, and therefore suitable for simulation in both Eclipse and CMG, but with lateral permeability barriers (shale plugs) capturing the dynamic impact of the Top A incision (Figure 4-10).

Given the complex fault geometries, specifically the close convergence of faults, variable cut-back distances have been used for fault/horizon intersection modelling. In addition, a significant amount of manual editing of the 3D grid was required to generate a grid capable of being simulated.

4.3.2.2 Tanin Complex

The Top A surface at Tanin is interpreted to be non-erosive and has been used explicitly as an input to the Tanin geological model. The B Sand is interpreted to be conformable to the A Sand, with the hydrocarbon leg at Tanin being entirely contained within the A and B Sands. The A Sand, AB Shale and B Sand surfaces have therefore been modelled with the True Vertical Thickness (TVT) seen in the Tanin-1 well (18m, 38m and 70m respectively). Given the low structural relief on the Tanin structure (with the exception of fault throws), TVT is considered a good proxy for True Stratigraphic Thickness. The C Sand has been modelled, with the Base C Sand being the base of the Tanin geological model. The C Sand has been modelled as a nominal 140m thickness (TVT from Tanin-1) and has been modelled as conformable to the B sands. Whilst the C sands are considered to be variable in thickness over the AOI, the C Sands are solely water bearing and therefore a simplified approach is appropriate within the aquifer.

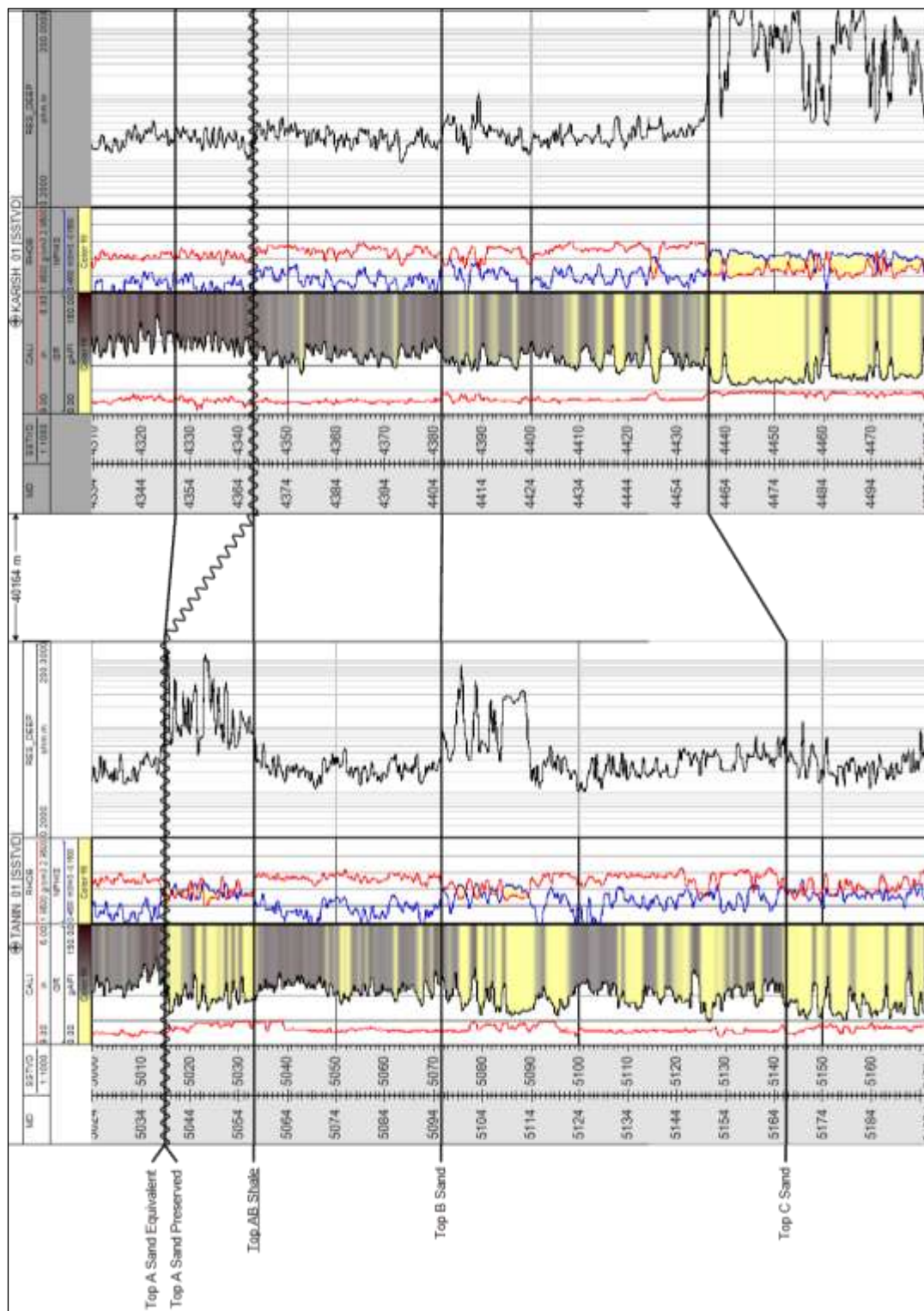


Figure 4-9 Correlation of the Karish-1 and Tanin-1 A and B Sands.

Figure Note: Tamar Sandstone Reservoir (Early Miocene). The interpreted unconformity at top reservoir within Karish-1 interpreted as being a local erosive channel cut, removing the A Sands at the Karish-1 location. This interpretation has seismic support (Section 2.4.6)

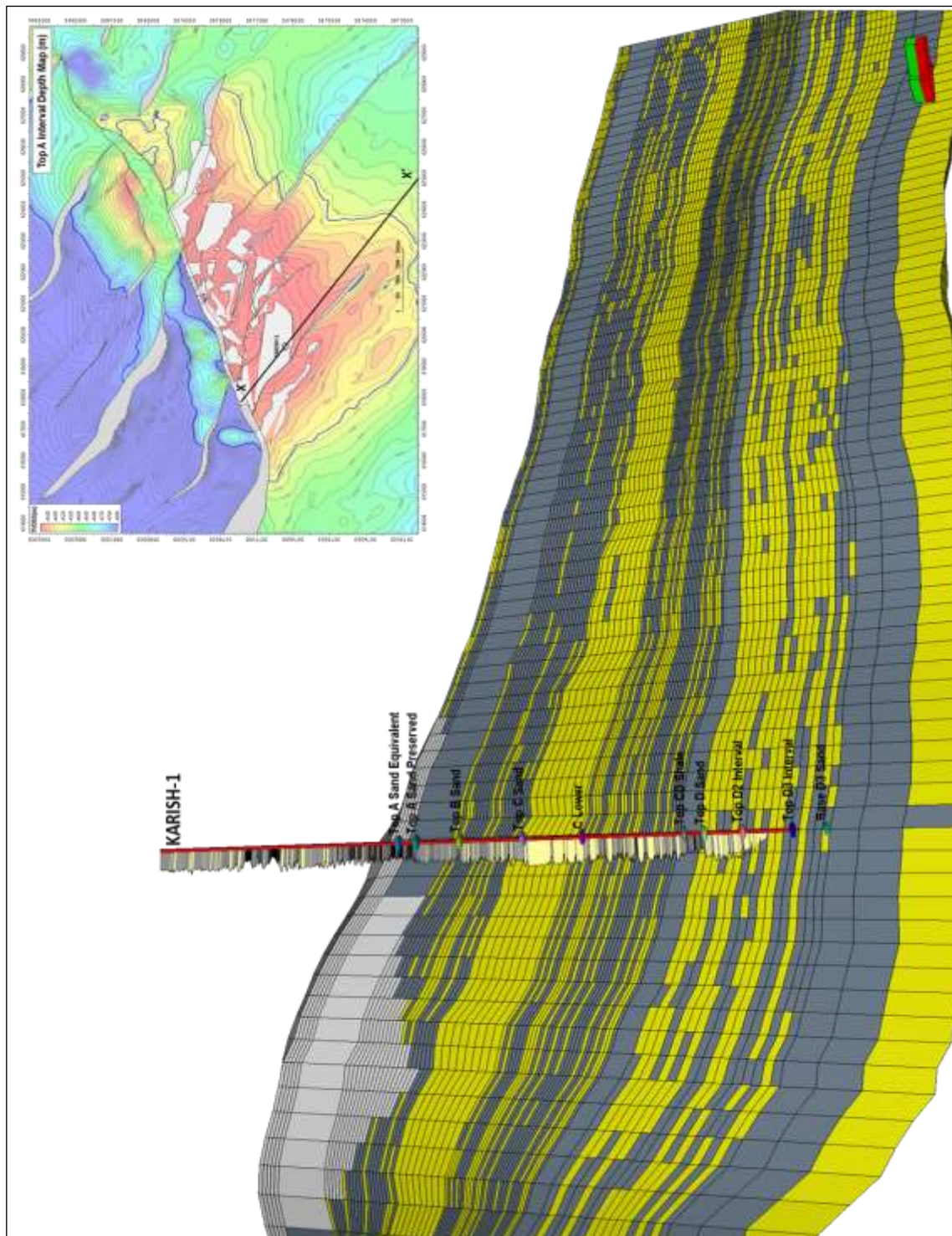


Figure 4-10 Geological Cross Section of the reference case Facies Model through the Karish-1 well.

Figure Note: all layering is conformable for ease of simulation with channel scours (as penetrated by the Karish-1 well) being modelled as shale plugs and subsequently zero permeability. Note the interpreted development of A Sands away from the Karish-1 channel scour.
Inset: Geographic position of geological cross section and areal distribution of channel scours at Top A Sand (grey polygons)

4.3.3 Model Zonation

4.3.3.1 Karish Complex

The zone scheme adopted in modelling the Karish field reflects the significant geographic extent of the accumulation, given that the zonal division of the reservoir goes beyond the simple subdivision of flow units. Non-reservoir sections interpreted to be field-wide, within stratigraphic units, have been explicitly modelled as individual zones. This allows these non-reservoir units to be modelled with a single layer where there is no requirement to accurately capture the reservoir character, and therefore results in a more economical use of 3D cells. This approach counteracts the significant number of cells (with small, 100m x 100m, lateral dimensions) required to grid the interpreted faults across the Karish structure and allows a geological model to be constructed with < 1 million active cells that can be simulated at geological scale, removing the need to upscale before dynamic modelling.

A total of 10 zones have been modelled and are shown in Figure 4-11. The rationale for the reservoir zonation is given in Table 4-2.

Table 4-2: Zonation Scheme for the Karish geological model

ZONE	STRATIGRAPHIC UNIT	DESCRIPTION
0	A Sand	Non- Net scour infill interval at Karish-1 but interpreted to have net reservoirs sands away from well control
1	AB Shale	Non-net interval
2	B Sand	Heterogenic interval with significant net component
3	C Sand (Upper)	Massive clean sand interval
4	C Sand (Lower)	Heterogenic interval, predominantly net sand
5	CD Shale	Non-net interval
6	D1-3 Sand	Heterogenic interval, predominantly net sand
7	D3 Shale	Non net interval within D3, modelled as separate zone to reduce number of layers in the D interval
8	D3.5 Shale	Non net interval within D3 defined by D3.5 interpreted surface, modelled as separate zone to reduce number of layers in the D interval
9	D4 Sand	Heterogenic interval, predominantly net sand entirely within aquifer

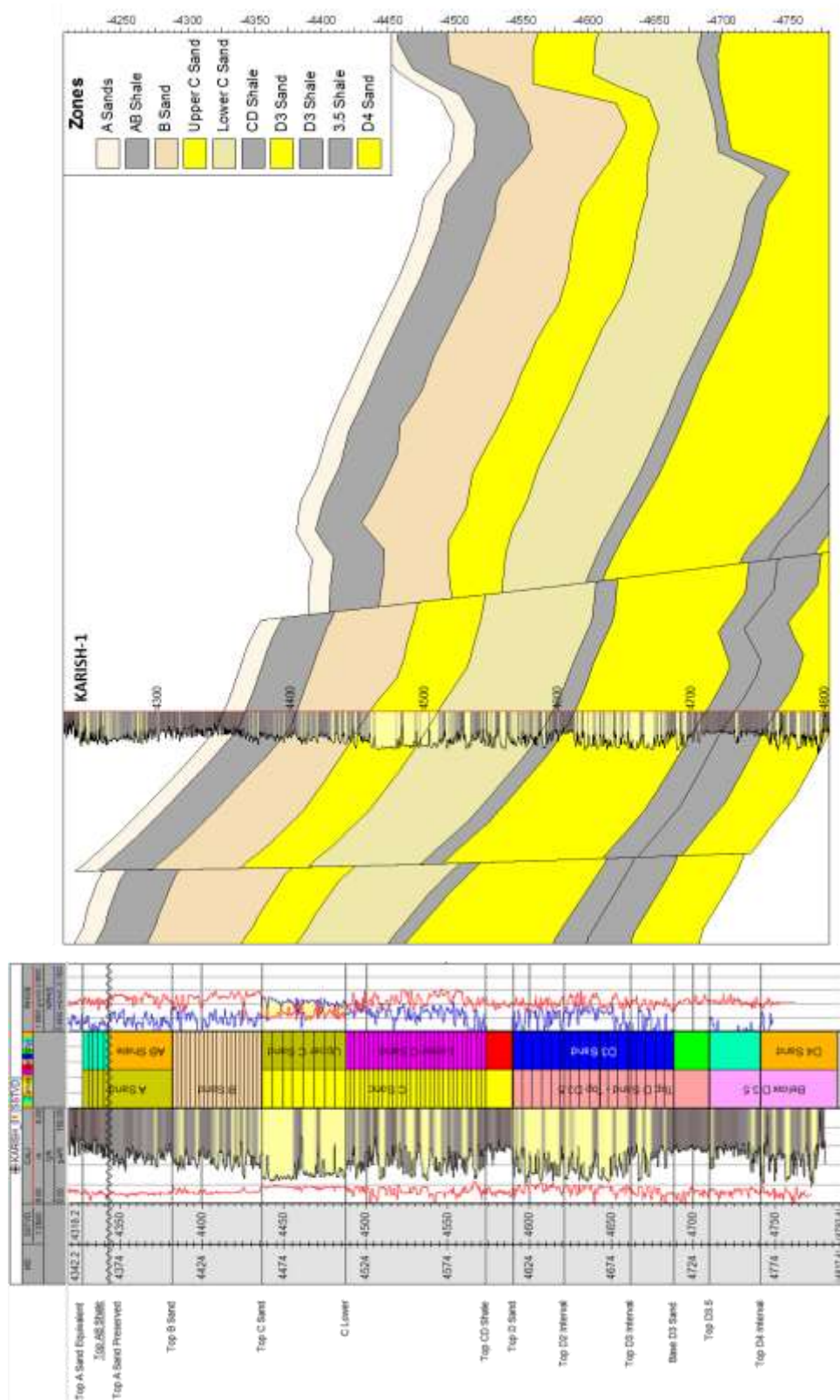


Figure 4-11 Karish Geological Model Zonation. Cross Section shown through Karish-1

4.3.3.2 Tanin Complex

The Tanin geological model has a more simplified zonation than Karish owing to the lower structural relief resulting in the gas leg being restricted to the A and B Sands only. The model zonation is given in Table 4-3

Table 4-3: Zonation Scheme for the Tanin Geological Model

ZONE	STRATIGRAPHIC UNIT	DESCRIPTION
0	A Sand	Net Reservoir Sands
1	AB Shale	Non-net interval
2	B Sand	Heterogenic interval, predominantly net sand
3	C Sand	Massive clean sand interval entirely with aquifer

4.3.4 Model Layering

Using the total porosity log as a QC, different layering schemes were investigated to ensure successful upscaling in terms of preserving the distribution and range of the input data (well log scale), whilst minimising the number of cells for efficient simulation. This was done by visual inspection of the total porosity histogram per zone along with cross-checking the volume weighted statistics per net reservoir unit. Non-net zones were assigned as a single layer to reduce the number of the cells in the geological model as far as practicably possible (Section 4.3.2).

4.3.4.1 Karish Complex

The resulting layering scheme adopted for the Karish geological model is given in

Table 4-4, with all layers being modelled as conformable. A QC on the upscaled PHIT property was made to ensure the layering scheme adequately captures the log data for the net reservoir sands (Figure 4-12). The resulting grid consists of 85 Layers and 4.22M grid cells. This is reduced to 1.27M cells when clipping to the AOI for simulation, of which 673k cells are active and simulates in 2hrs without further upscaling.

Table 4-4: Layering Scheme used for the Karish Complex geological model. Values shown are for the clipped grid (Figure 4-6) which has been used for simulation

ZONE	STRATIGRAPHIC UNIT	NUMBER OF LAYERS	AVERAGE THICKNESS (M)	NUMBER OF CELLS IN LAYER
0	A Sand	5	3.1	72765
1	AB Shale	1	37.1	14553
2	B Sand	20	3.9	291060
3	C Sand (Upper)	8	5.0	116424
4	C Sand (Lower)	30	2.3	436590
5	CD Shale	1	13.3	14553
6	D1-3 Sand	17	5.8	247401
7	D3 Shale	1	20.8	14553
8	D3.5 Shale	1	31.3	14553
9	D4 Sand	1	48.4	14553

4.3.4.2 Tanin Complex

The resulting grid consists of 52 Layers and 1.46 grid cells (Table 4-5), of which 465k cells are active and simulates in <2hrs without further upscaling.

Table 4-5: Layering Scheme used for the Tanin Geological model. Values shown are for the clipped grid (Figure 4-7) which has been used for simulation

ZONE	STRATIGRAPHIC UNIT	NUMBER OF LAYERS	AVERAGE THICKNESS (M)	NUMBER OF CELLS IN LAYER
0	A Sand	15	1.3	410190
1	AB Shale	1	37.9	27694
2	B Sand	35	2.0	957110
3	C Sand	1	144.0	27694

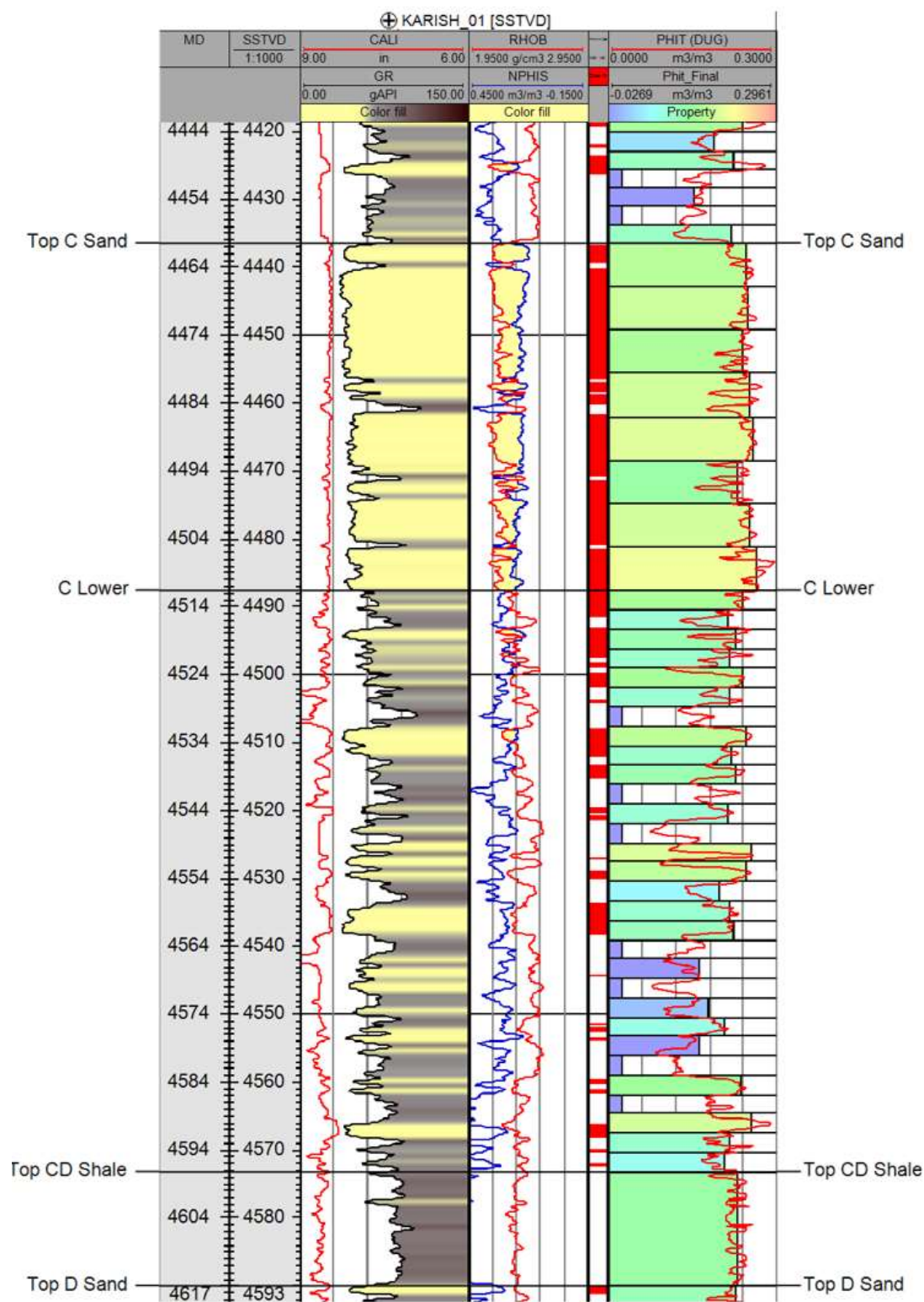


Figure 4-12 QC of adopted layering scheme.

Figure Note: The Karish-1 calculated total porosity (red curve/right hand track – log scale) overlain on the total porosity property upscaled to the geological model. A good match of well log to upscaled porosity is observed over the net reservoir interval (red intervals, third track)

4.3.5 Fluid Contacts

The main data used for the determination of the fluid contacts for Karish-1 and Tanin-1 are formation pressures. The log data is used as a QC of the interpretation of the formation pressure data, but cannot be solely relied upon. For Karish-1, a shale prone interval of the C Sand is coincident with the interpreted GWC (4512m TVDSS), resulting in a Gas-Down-To (GDT) in the Karish-1 well at 4510m TVDSS (Figure 4-13). Tanin-1 has a GDT as the base of C Sand, with gas on rock interpreted at a depth of 5090m tvdss (Figure 4-14). The interpreted GWC for Tanin is 5095m TVDSS.

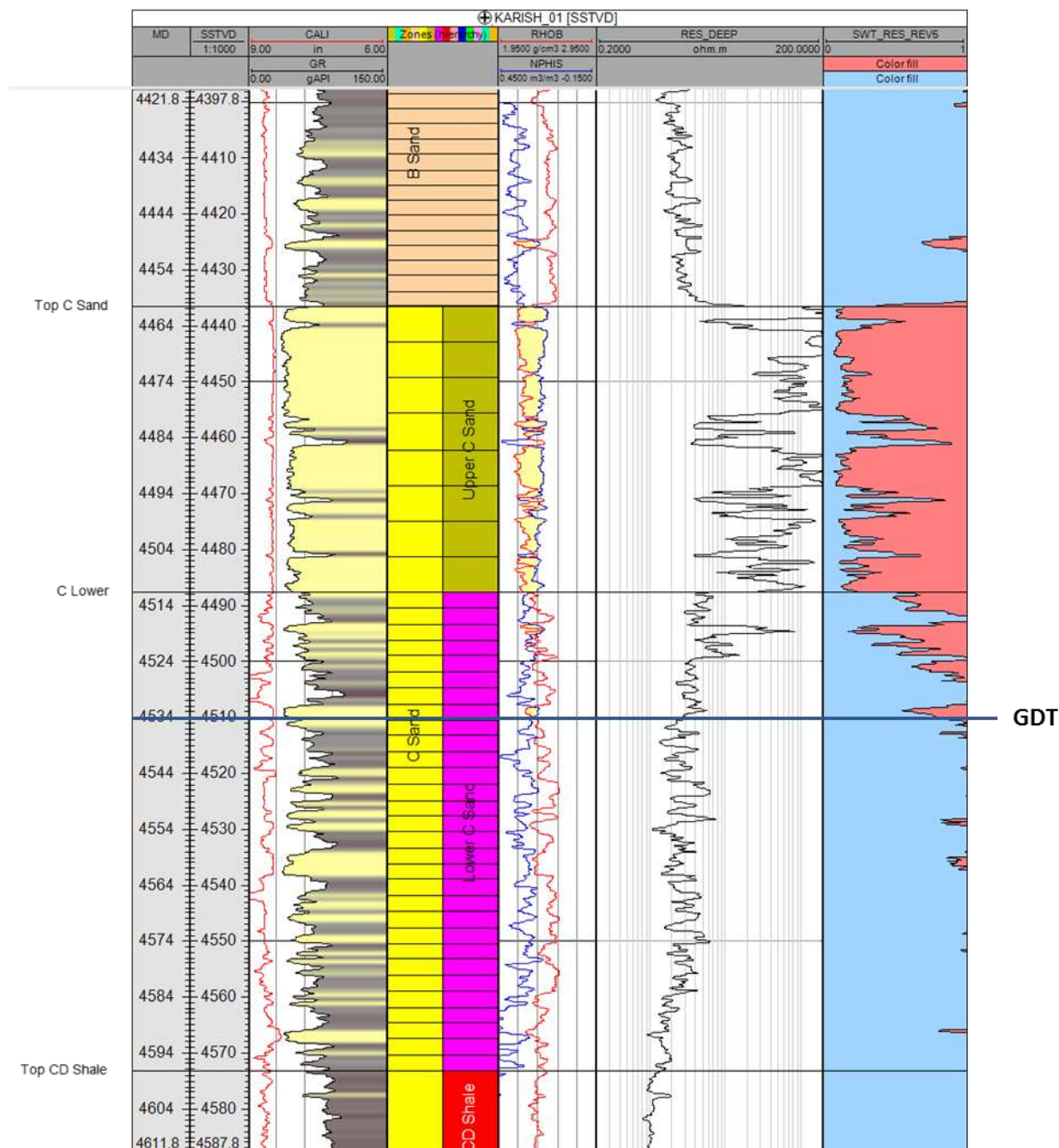


Figure 4-13 Karish-1 Interpretation of Gas-Down-To (GDT) at 4510m TVDSS within the Lower C Sand.

Figure Note: No Gas-Water-Contact (GWC) is observed

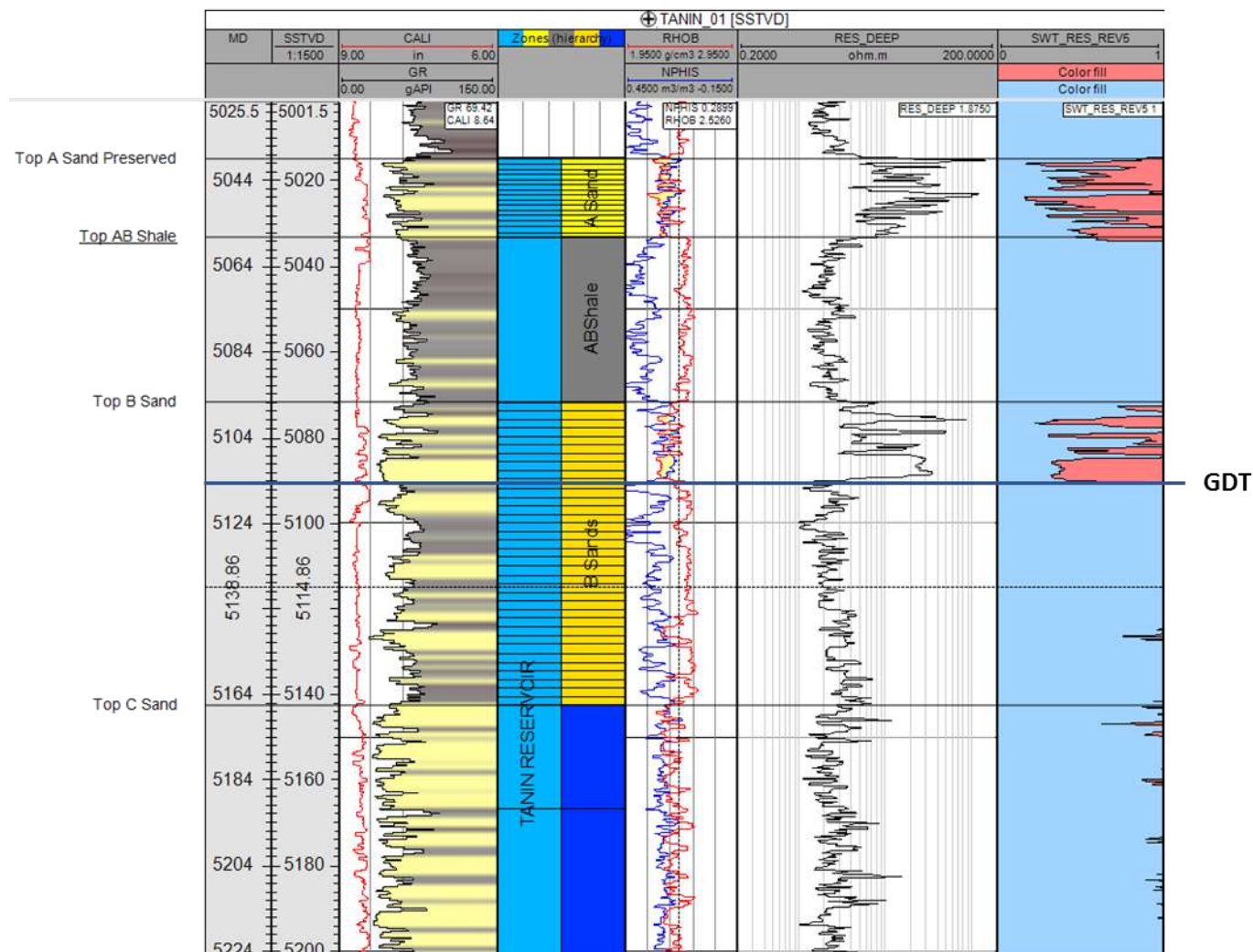


Figure 4-14 Tanin-1 interpretation of a GDT at 5090m TVDSS.

Figure Note: No GWC is observed in this well

4.3.6 Formation Pressures

Tanin-1 and Karish-1 have good quality formation pressure data, acquired with Baker Hughes's Reservoir Characterisation Instrument (RCI) on wireline. Of the 70 pressure stations attempted across the two wells, 35 successful pressure readings were acquired with good stability (<0.05psi/min) and good repeatability (0.1 psi/min).

4.3.6.1 Gas Gradient

4.3.6.1.1 Karish-1

The C sand formation pressures in Karish-1 gives a very high confidence gas gradient of 0.128psi/ft. (Figure 4-15), which is a slightly elevated from a dry gas gradient and is consistent with PVT data which suggests a wet gas at surface, yielding a CGR of up to 26bbbl/mmscf. This gas gradient and a high confidence aquifer gradient puts the Free Water Level (FWL) at 4512 mTVDSS. Given the 200mD+ quality of the C sands, the FWL is considered to be coincident with the Gas Water Contact (GWC)

Three pressure stations were taken within the Karish-1 B Sand which appear to be 5 psi higher than the C Sand. A gas gradient of 0.128psi/ft., consistent with the underlying C sands appears to be a robust interpretation. The 5 psi difference, if genuine, would put the FWL at 4517m TVDSS, some 5m deeper than the C Sand FWL. The 5psi difference may be genuine, but could however be due to the relatively poor reservoir quality of the B Sands, and with just three pressure stations, supercharging cannot be ruled out.

Two formation pressures were also taken in the A interval in Karish-1. Based on the most recent correlation (Section 4.2.2), this section is now interpreted to be mid-Miocene backfilling of the early Miocene channel scour cut, and is therefore stratigraphically separate from the Tamar sands at Karish. This section, being 50psi over pressured relative to the B and C sands below, provides an interesting insight into the degree of uplift on the Karish structure since the reservoir was charged. Assuming the overpressure is due to the inability to equilibrate (depressurise) an isolated silty section of the Karish top seal, a 50 psi overpressure within a gas interval equates to (391ft/119m) of uplift since being charged. This overpressure demonstrates that the silty interval within the top seal at Karish-1 is not capable of acting as a significant thief zone. Any A sand that may be present on the flank of Karish structure, away from the Karish-1 well is expected to be in pressure communication with a B/C sand and therefore have a FWL at 4512m TVDSS.

Given the high density and high quality formation pressure data over the Karish-1 Tamar sand, a differential pressure plot of the gas bearing interval (excluding the mid-Miocene top seal pressures) was made (Figure 4-15). This type of plot normalises formation pressures between consecutive pressure stations and can therefore be used to identify formation pressure 'breaks' typically across shales which may indicate vertical compartmentalisation. Figure 4-15 shows that for the high quality pressure points, there are < 1psi change between consecutive pressure points. This would indicate a low probability of vertical compartmentalisation over geological time which may indicate favourable vertical connectivity over a production life-time.

4.3.6.1.2 Tanin-1

Gas interval formation pressures in Tanin-1 (Figure 4-16) show the A/B sands to plot on the same dry gas gradient of 0.118 psi/ft. This is a lower gradient than interpreted in the Karish-1 well (Section 4.3.5.1.1) which is consistent with the lower CGR of 5bbl/mmscf. The gas interval pressures give a high confidence FWL, assumed to be coincident with the GWC, of 5095m TVDSS.

4.3.6.2 Water Gradient

Both Karish-1 and Tanin-1 acquired good quality formation pressure data in the water bearing interval. This has resulted in a high confidence water gradient of 0.446 psi/ft. in both Karish and Tanin.

Utilising the formation pressure data for Myra-1 and Aphrodite-2 from the 1st Offshore Round data package (Ministry of National Infrastructures, Energy and Water Resources), the water gradient is shown to be consistent, and more significantly, the formation pressure at any given datum appears to be equal (Figure 4-17). The formation pressure dataset on which this observation is made, covers a significant geographic area (lateral offsets given in Table 4-6), with a probable interpretation being that the aquifer is connected over the majority, if not all of the Levant Basin. This results in a high probability of strong aquifer support in both the Karish and Tanin fields.

Table 4-6: Lateral offset (in km) of wells used for aquifer formation pressures

	Karish-1	Tanin-1	Aphrodite-2	Myra-1
Karish-1		40.2	87.9	75.6
Tanin-1	40.2		48.9	63.0
Aphrodite-2	87.9	48.9		90.1
Myra-1	75.6	63.0	90.1	

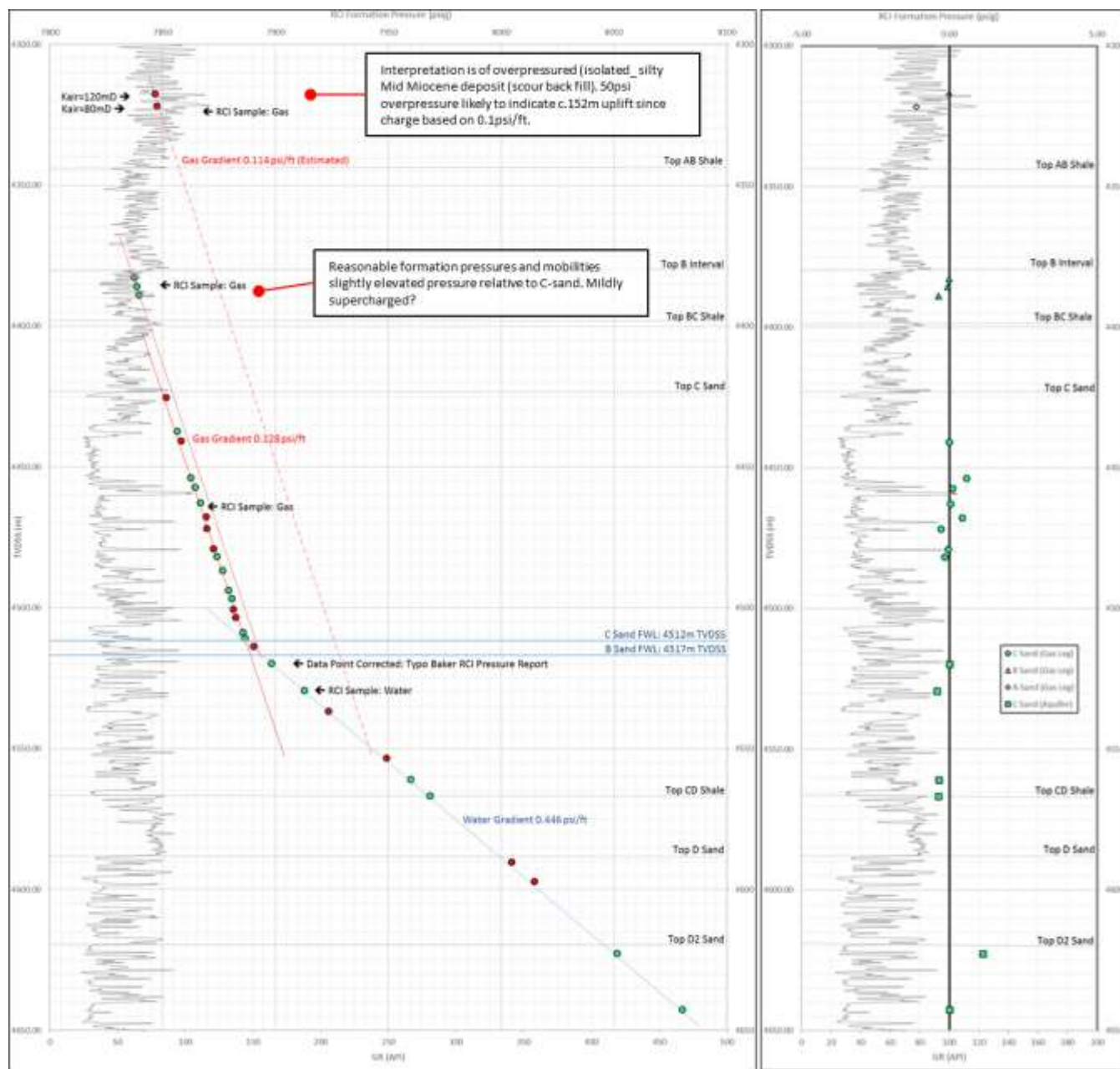


Figure 4-15 Main Karish-1 Formation pressures and Operator interpretation.

Figure Notes: Right: Formation pressure differential plot showing <1psi difference between consecutive pressure station suggesting vertical connectivity over geological time

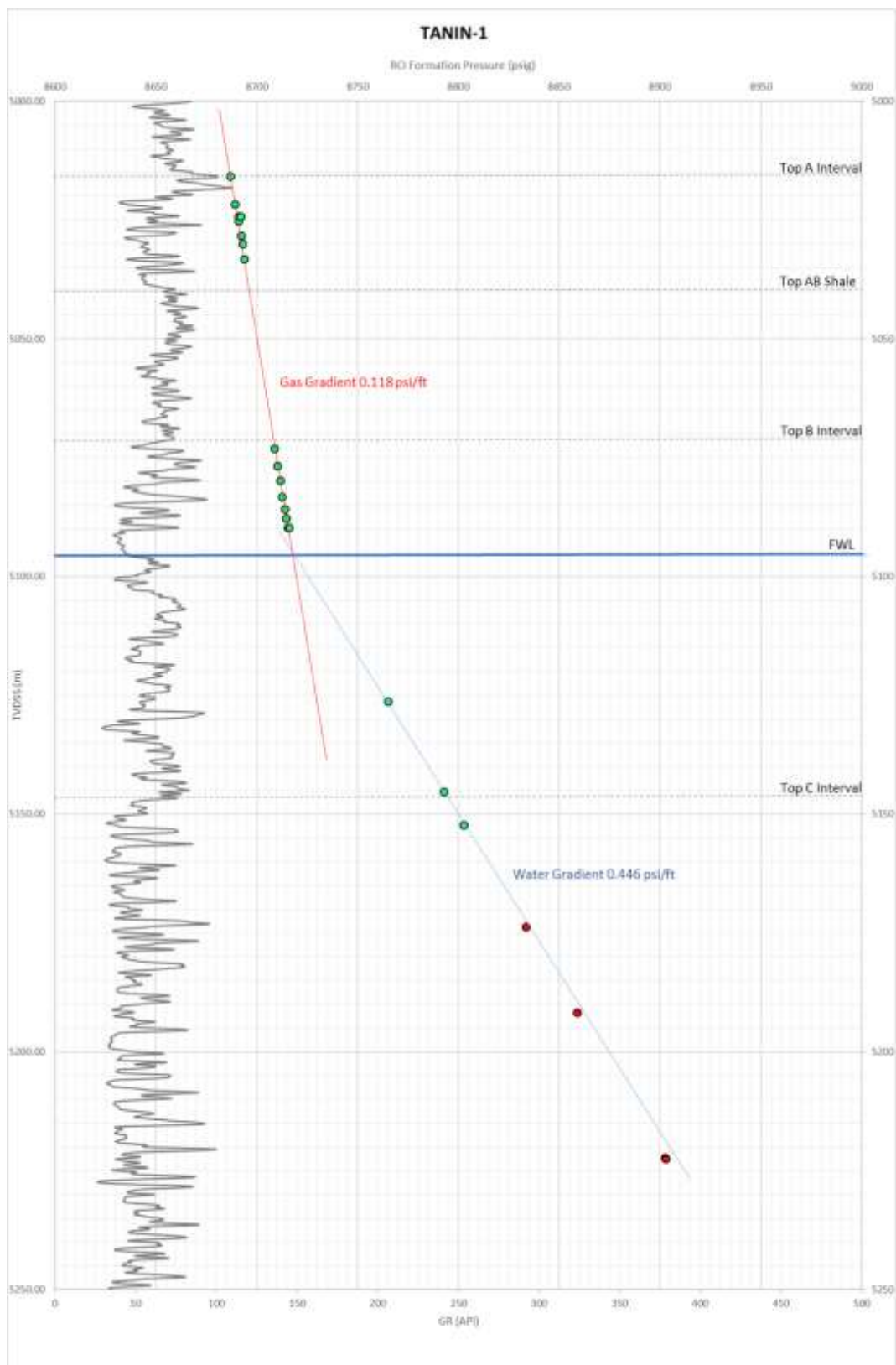


Figure 4-16 Tanin-1 Formation Pressure Data & Interpretation of FWL

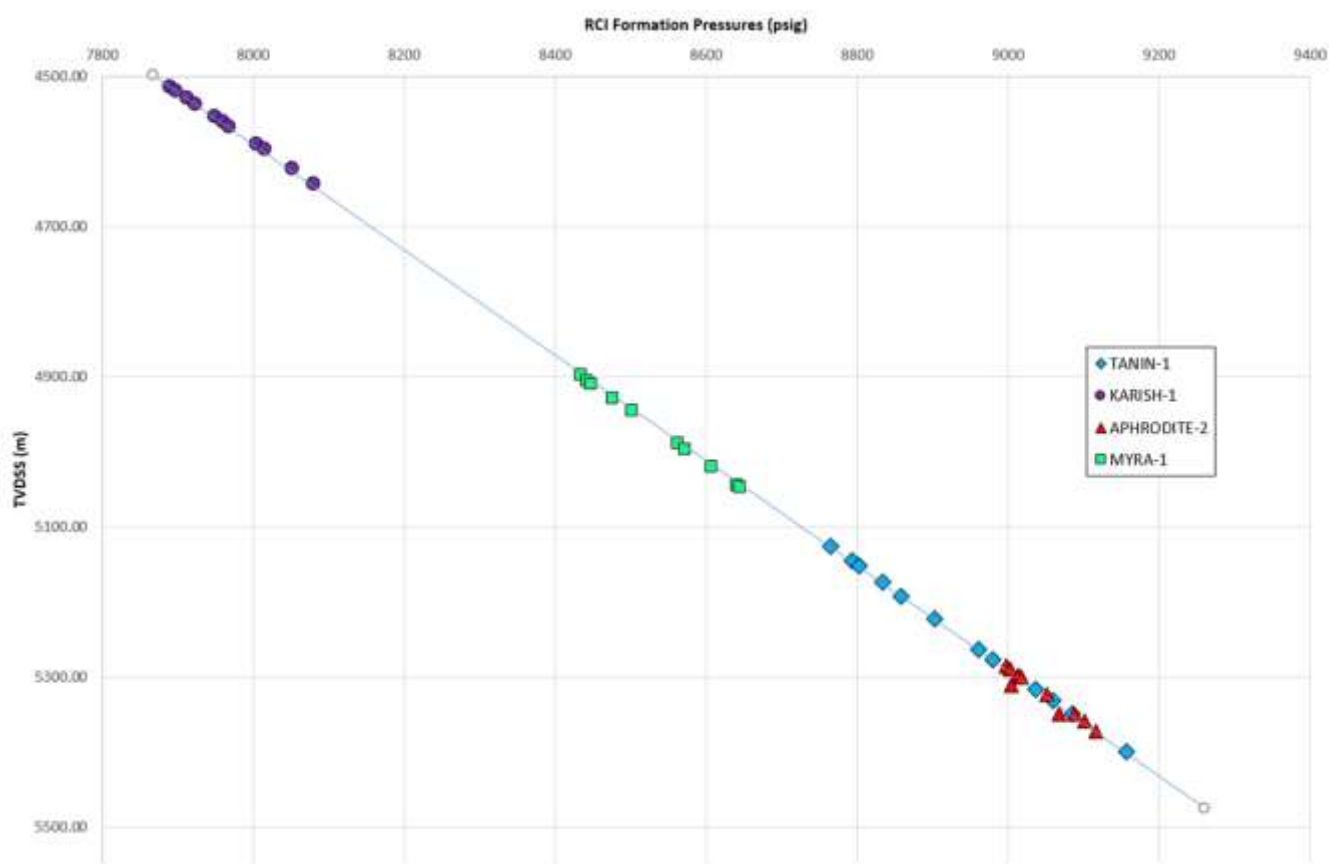


Figure 4-17 Levant Basin Aquifer Formation Pressures.

Figure Note: All available data appears to plot on the same water gradient (0.446psi/ft.) and significantly at the same formation pressure for any given depth indicating probable good connectivity of the aquifer

4.3.6.3 Modelled Gas Water Contacts

With the Karish field having >300m gas column, the 5psi uncertainty between the B and C sands (Section 4.3.5.1.1) is considered to be volumetrically insignificant. The Karish Main GWC has in all units been modelled as a field wide contact at 4512m TVDSS which is consistent with the RCI samples from Karish-1 (Figure 4-15). There is considered to be <5m uncertainty in the GWC within the C Sand.

For Karish North a GWC of 4774m TVDSS has been modelled which is consistent with the DHI observed on the PSDM seismic data (Section 2.4.8). Given the probable C sand/C sand juxtaposition between Karish North and Karish East along with the coincidence of the Karish North DHI with the structural spill point of Karish East (Figure 4-4), the Karish East GWC has also been modelled at 4774m TVDSS.

The Tanin GWC has been modelled as a field-wide contact at 5095m, which again is consistent with the RCI Fluid samples acquired. There is considered to be <5m uncertainty in the GWC within the A/B Sands.

4.4 Facies Model

4.4.1 Facies Log

Given a lack of conventional core data and the seemingly binary nature of the reservoir, a simple sand/shale approach has been used to generate a lithology log (facies log) as the input to the facies model.

A Vshale cut-off of >0.5 and effective porosity <0.08 has been used to assign shale, with net sand being any values out with the cut-off. A sensitivity to the net reservoir cut-off (Figure 4-18) was performed, with the effective porosity being found to be less sensitive than Vshale. VShale was found to be the more significant cut-off parameter, particularly in the B Sand Interval (4405-4460m MDBRT) in the Karish-1 well.

A cut-off of 8.p.u. was deemed to be reasonable for the Karish reservoir, given this equates to c.0.05mD horizontal permeability (Section 4.5.2) and given the Karish field hydrocarbon fluid phase. The VShale value of 0.5 was used as the cut-off, which is a generic, widely accepted cut-off amongst many operators. For the Karish B and Lower C Sand reservoirs, this is considered to be a conservative approach (i.e. underestimating the amount of net sand). Given the thinly bedded nature of the B Sand Interval (Section 3), the GR and resistivity log are both expected to be biased towards the more conductive and radioactive beds (GR tool measures radioactivity and the 'resistivity' tool measures conductivity), therefore giving an underestimate of both net reservoir and net pay.

The resulting facies log consists of three 'facies' types, as given in Table 4-7.

The resulting facies log for Karish-1 is shown in Figure 4-19

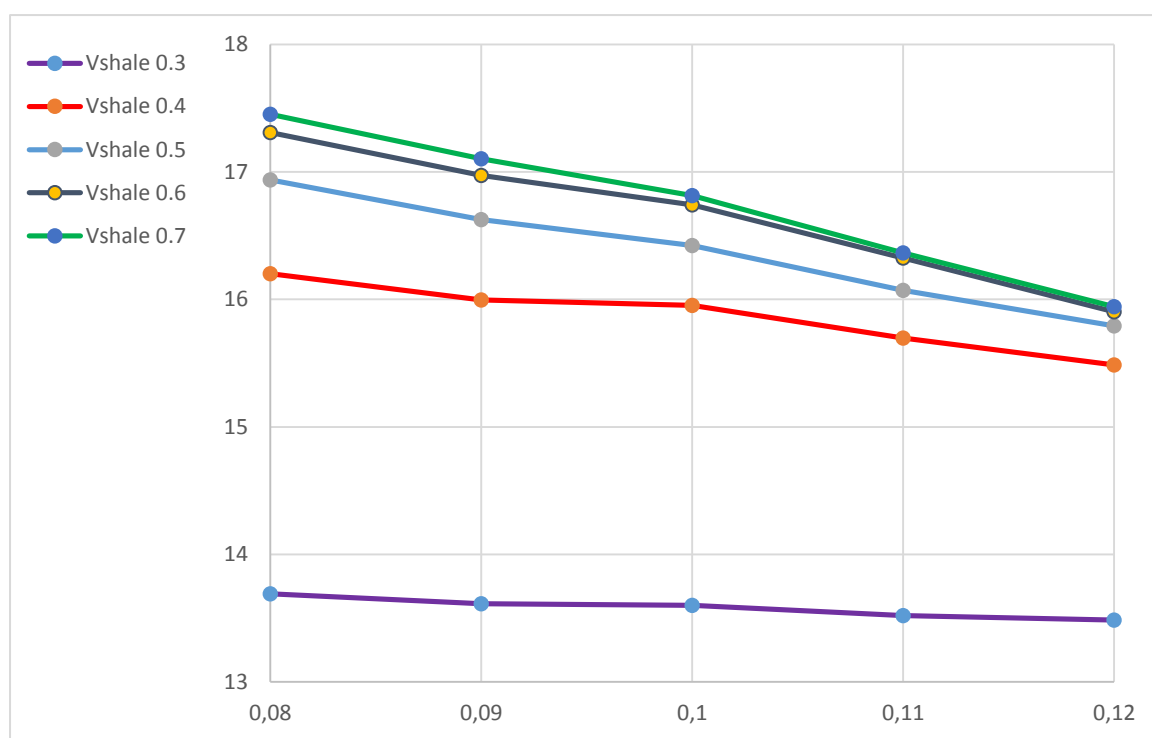


Figure 4-18 Hydrocarbon Pore Thickness Sensitivity.

Figure Notes: (m – y axis) sensitivity to VShale and PHIE porosity cut-offs used to define net reservoir sand

Table 4-7: Karish and Tanin Facies Log definition

FACIES CODE	FACIES	DEFINITION
0	Net Sand	Vshale <0.5 and PHIE>0.08
1	Mudstone	Vshale >0.5 and PHIE<0.08
2	Mid Miocene Scour Fill	Silty mudstone within overburden – present in the Karish-1 well over interval 4405m – 4460m MDBRT. Modelled explicitly as mapable scours

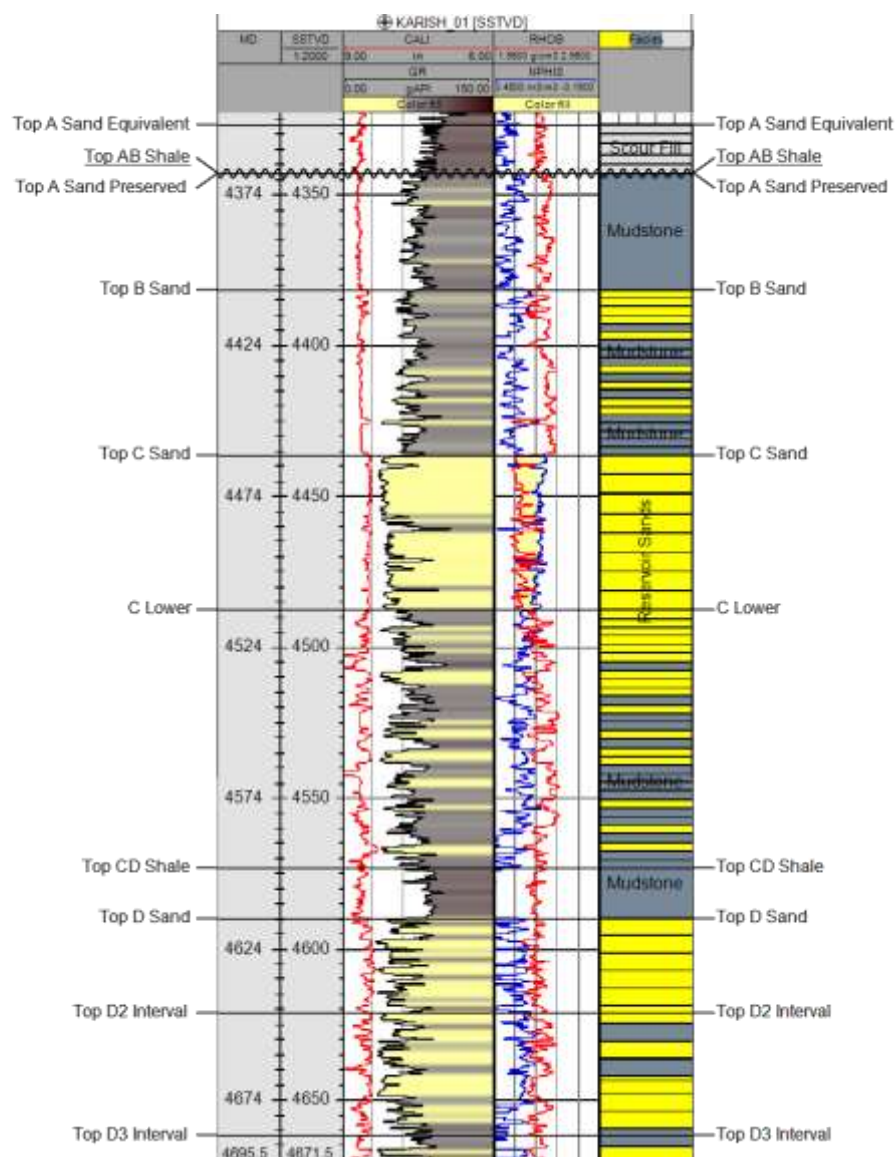


Figure 4-19 Karish-1 Facies Log.

Figure Note: Channel scour facies interpreted as a back filled channel scour (Section 4.2.2)

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4.4.2 Upscaling of Facies Log

Upscaling was performed using the ‘most of’ methodology.

In detail, the upscaling fails to capture many of the thin sands, for example within the AB Shale interval (Table 4-7). This is unavoidable without building a geological model at well log scale (<0.5ft layer resolution) which is considered unfeasible for computation time and upscaling. For the reasons discussed in Section 4.3.2, the geological model has been built at simulation model scale, with any loss of fine detail considered to be acceptable to avoid inaccuracies associated with vertical upscaling of the geological model.

4.4.3 Facies Property Modelling

4.4.3.1 Methodology

The methodology used for facies modelling is Sequential Indicator Simulation (SIS) with variogram ranges being utilised from bathymetrically unconstrained outer submarine fan deposits of the Central North Sea. In the Karish geological model, secondary conditioning to net sand trend maps in each reservoir unit has been used.

Given Energean’s detailed interpretation of the individual reservoir units across Karish and given variations of the reservoir stratigraphic thickness is likely to be driven by the spatial distribution of clastic input, it is reasonable to use the isochores of each of the reservoir units as a proxy for sand distribution. The underlying assumption being that the interpreted reservoir thickness is linearly proportional to net sand thickness.

A further underlying assumption of the facies model is that the Karish-1 well is entirely representative of the reservoir away from the point of well control i.e. with the exception of Facies Code 2 (mid Miocene scour fill which have been explicitly mapped) the facies proportions of net sand to non-net mudstones interpreted in the Karish-1 well is equal to that of the entire field area.

4.4.3.2 Facies Proportions

An underlying assumption of the facies model is that the Karish-1 well is entirely representative of the reservoir away from the point of well control i.e. with the exception of Facies Code 2 (mid Miocene scour fill which have been explicitly mapped) the facies proportions of net sand to non-net mudstones interpreted in the Karish-1 well is equal to that of the entire field area.

The facies proportions have therefore been defined per zone by the proportions seen in the Karish-1 and Tanin-1 for the Karish and Tanin geological models respectively. It is important to note that the facies proportions have been set as well log scale and not from the upscaled data. Given the coarse layering adopted for the geological model (Section 4.3.3) using upscaled cells to define facies proportions would result in a facies model that is not consistent with the facies proportions observed in the well data.

The facies proportions used in the geological model are given in Table 4-8 and Table 4-9.

The absence of well-developed net reservoir sands in the A Sand interval is interpreted to be due to the penetration of a local channel scour in the vicinity of the Karish-1 well. Away from the interpreted channel scours (Section 2) the A sand has been modelled to be consistent with the A sand net reservoir thickness intersected in the Tanin-1 well. The resulting facies model therefore does not reflect the Karish-1 well data at the A Sand interval, given that Karish-1 is interpreted to not be representative of the stratigraphic interval away from the point of well control.

In the Karish geological model, the A Sand, AB Shale and B Sand include the Channel Scour facies. This is not separately captured within the facies log, being present in the Karish-1 well as a mudstone (Facies Code 1) – Section 4.4.1. The Channel Scour facies (Facies Code 2) is assigned above in the erosive surface (Section 2) of the Upper A Sand in the facies modelling process using the property calculator.

In the predominantly non-net AB Shale, the facies model does not accurately reflect the proportions observed in either Karish-1 or Tanin-1. Given the low net sand content of the AB Shale, any net reservoir sands are likely to be isolated and therefore will not contribute to production. The AB Shale is therefore modelled as a single layer thick (Section 4.3.3) i.e. reduce the number of cells in the geological model in preference to trying to accurately model this interval.

The Karish D3 Shale, 3.5 Shale and D4 Sand have been modelled as a single layer, with the latter being modelled as a sand to capture the aquifer should this need to be explicitly modelled. The D3 and 3.5 Shales have been modelled as a single layer to use the layering economically given the low net sand component of these intervals.

Table 4-8: Facies Proportions for the Karish Geological Model

ZONE		FACIES	CODE	WELL PROPORTION	MODELLED PROPORTION
0	A Sand	Reservoir Sands	0	2.6	69.8
		Mudstone	1	97.4	25.1
		Channel Scour	2	0	5.1
1	AB Shale	Reservoir Sands	0	5.8	0
		Mudstone	1	94.2	97.9
		Channel Scour	2	0	2.1
2	B Sand	Reservoir Sands	0	44.6	44.9
		Mudstone	1	55.4	54.4
		Channel Scour	2	0	0.7
3	Upper C Sand	Reservoir Sands	0	92.7	93.1
		Mudstone	1	7.3	6.9
4	Lower C Sand	Reservoir Sands	0	52.1	55.2
		Mudstone	1	47.9	44.8
5	CD Shale	Reservoir Sands	0	0.4	0
		Mudstone	1	99.6	100
6	D3 Sand	Reservoir Sands	0	51.7	57.2
		Mudstone	1	48.3	42.8
7	D3 Shale	Reservoir Sands	0	0	0
		Mudstone	1	100	100
8	3.5 Shale	Reservoir Sands	0	6.3	0
		Mudstone	1	93.7	100
9	D4 Sand	Reservoir Sands	0	30.6	100
		Mudstone	1	69.4	0

Table 4-9: Facies Proportions for the Tanin Geological Model

ZONE		FACIES	CODE	WELL PROPORTION	MODELLED PROPORTION
0	A Sand	Reservoir Sands	0	86.0	84.0
		Mudstone	1	97.4	16.0
1	AB Shale	Reservoir Sands	0	3.5	0
		Mudstone	1	96.5	100.0
2	B Sand	Reservoir Sands	0	34.6	34.8
		Mudstone	1	65.4	65.2
3	C Sand	Reservoir Sands	0	61.5	100
		Mudstone	1	38.5	0

4.4.3.3 Trend Maps

Variations of the reservoir true stratigraphic thickness is likely to be driven by the spatial distribution of clastic input, it is reasonable to use the isochores of each of the reservoir units (Section 2) as a proxy for sand distribution. An underlying assumption is that the interpreted reservoir thickness is linearly proportional to net sand thickness.

For each reservoir unit of the Karish field geological model, a normalised isochore map has been used as a secondary control on the distribution of net reservoir sands.

The contours from the isochore maps were also used as a local varying azimuth for the variogram settings to make a more geologically reasonable facies model and avoid linear features that result from a single variogram azimuth setting which results in a model with reduced flow path tortuosity.

4.4.3.4 Resulting Facies Models

The resulting facies proportions maps for each reservoir unit of the Karish geological model are given in Figure 4-20 - Figure 4-24 .

Given the relative absence of an intra reservoir interpretation across Tanin, no isochores are used in the construction of the Tanin complex facies model.

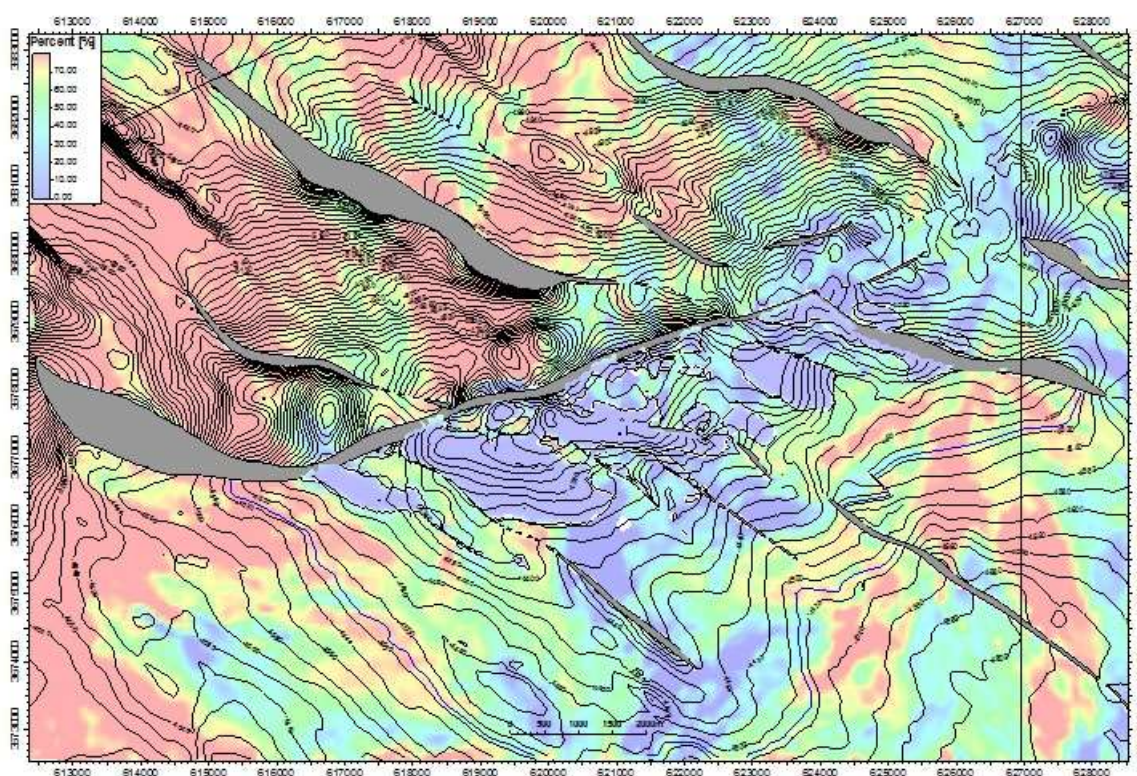


Figure 4-20 Reference Case Geological Model Net Sand (Facies Code 0) Proportion Map

A Sands

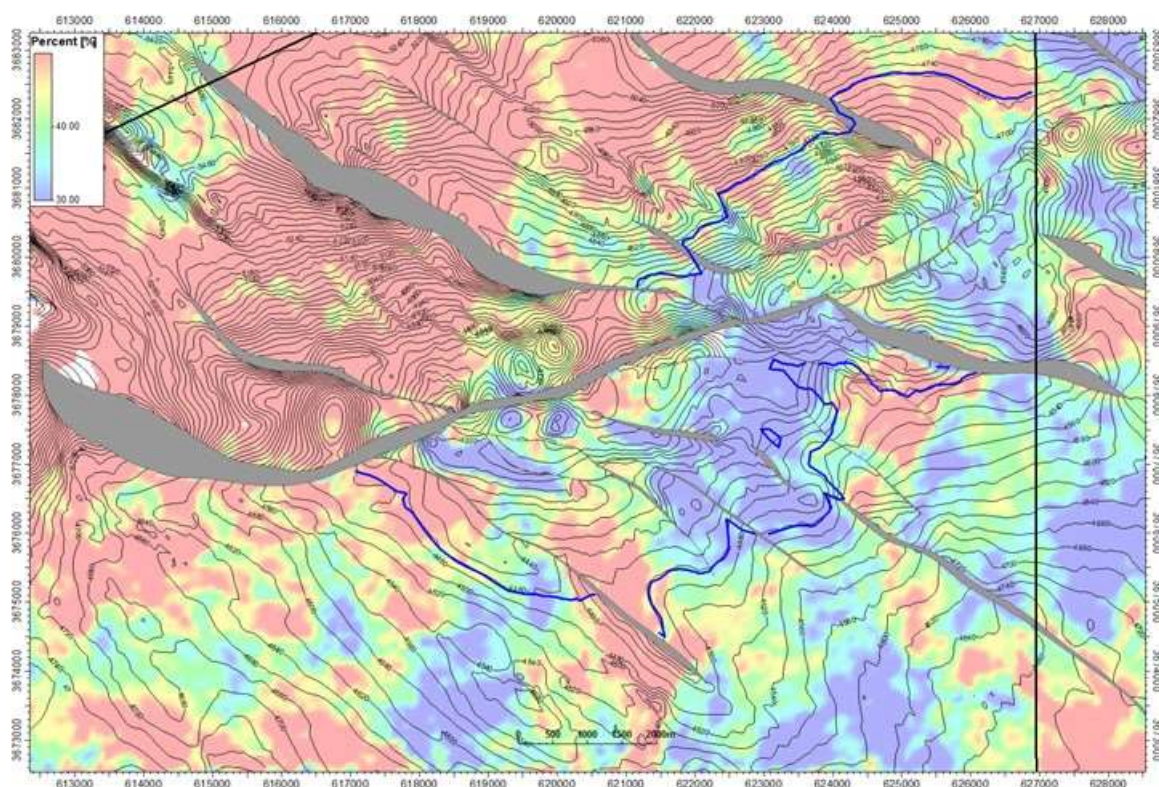


Figure 4-21 Reference Case Geological Model Net Sand (Facies Code 0) Proportion Map

B Sands

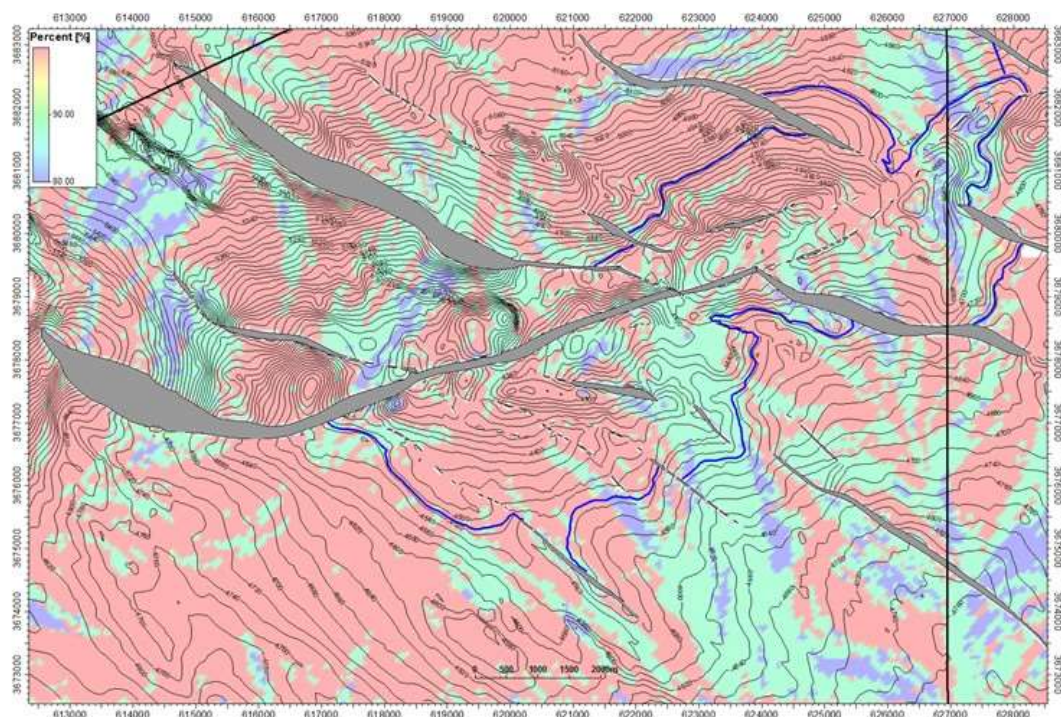


Figure 4-22 Reference Case Geological Model Net Sand (Facies Code 0) Proportion Map
Upper C Sands

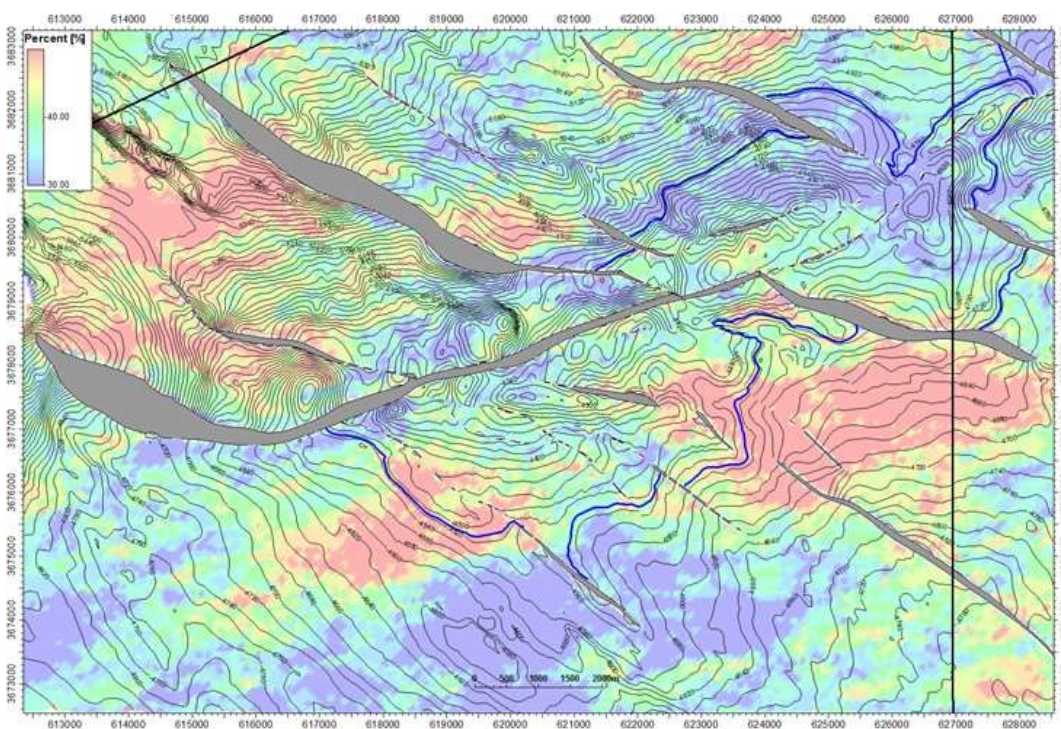


Figure 4-23 Reference Case Geological Model Net Sand (Facies Code 0) Proportion Map
Lower C Sands

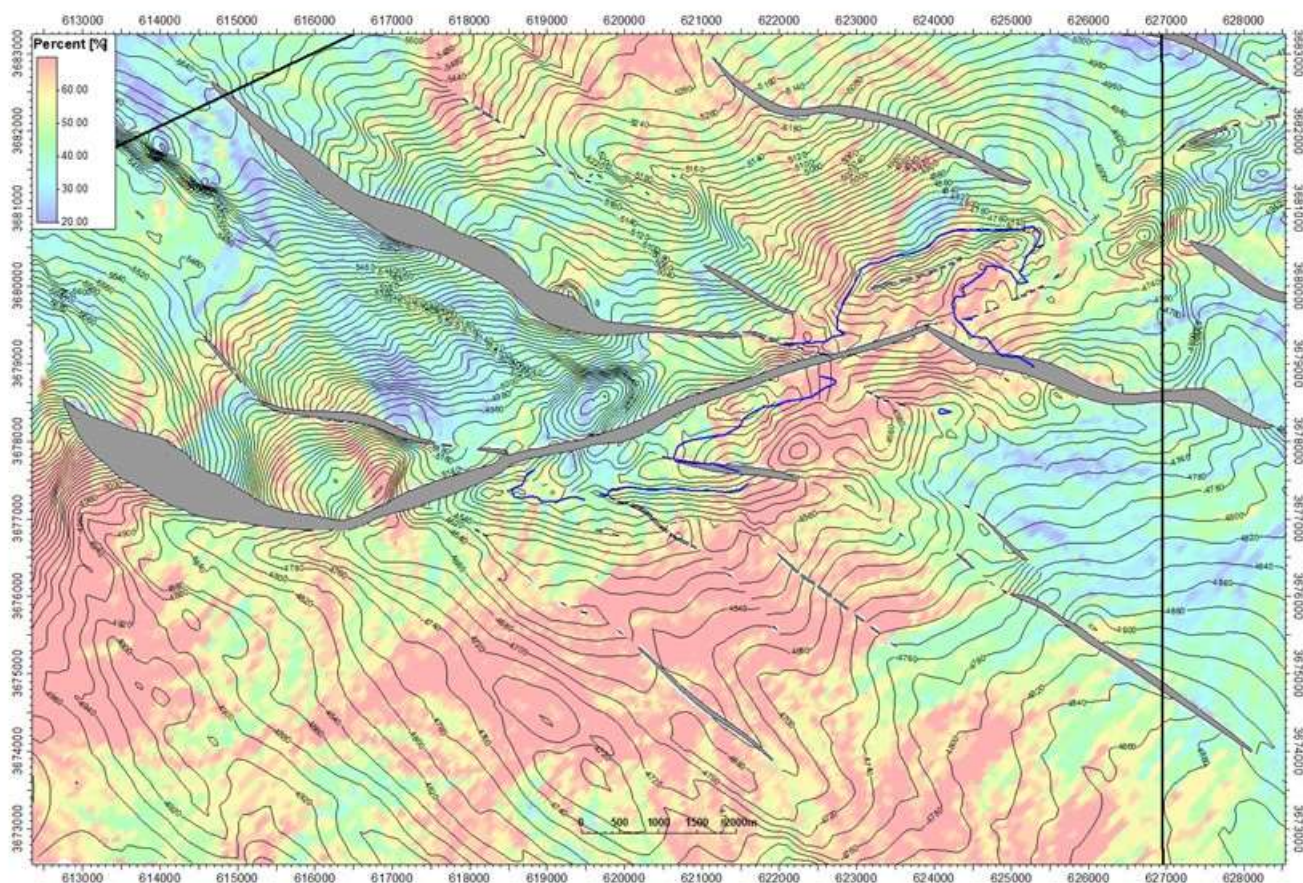


Figure 4-24 Reference Case Geological Model Net Sand (Facies Code 0) Proportion Map
D3 Sands

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4.5 Petrophysical Models

4.5.1 Porosity Models

Both a total and effective porosity model were generated, the former to model in place volume and relate the available core data to the geological model, and the latter to enable modelling of the Karish water saturation (Section 4.5.3). Both porosity models are constrained by the facies model (Section 4.4.3) and use the DUG petrophysical analysis as the input (Section 3). The model assumption is that the Karish-1 and Tanin-1 wells are entirely representative of the Karish and Tanin reservoirs respectively.

4.5.1.1 Petrophysical Log Editing

The generated facies logs (Section 4.4.1) are essentially a binary product with net and non-net reservoir. Prior to upscaling the DUG petrophysical logs into the geological model, porosity values (both total and effective) within the non-net facies (Facies Codes 1 and 2) were unassigned (nulled). Given that effective porosity had already been used as a discriminator for non-net reservoir, any values in these intervals should not been included in the upscaling (averaging) of the porosity logs. The output of the geological model should be net total porosity and net effective porosity, given the facies model and subsequent net to gross model remove any bulk volume associated with non-net facies.

This was achieved in the well log calculator using:

$$PHIE = \text{if (Facies}=0, PHIE, \text{ if (Facies}>1, u, PHIE))$$

$$PHIT = \text{if (Facies}=0, PHIE, \text{ if (Facies}>1, u, PHIT))$$

4.5.1.2 Upscaling of Porosity Logs

The porosity logs have been upscaled arithmetically as line data with a bias to facies (Section 4.4).

For the Karish model, only the Karish-1 well data has been upscaled. This is due to the lateral offset between Karish-1 and Tanin-1 (40.2km) exceeding the skeleton grid dimensions.

Likewise, for the Tanin geological model, only the Tanin-1 well data has been upscaled.

For the Karish Complex A Sand interval (4351m – 4369m MDBRT), the net effective and total porosity values from the Tanin-1 well have been used to model the net sand porosity away from the Karish-1 well where the sands are interpreted as have being eroded by a local channel scour feature (Section 2).

It is important to note that due to limited data (a single well in the Karish and Tanin structures) and the objective of building the geological model at simulation scale, the upscaling process results in a significant averaging of the porosity logs where all values strongly converge around the mode of the porosity at well log scale, with a significant decrease in the range of porosity in the upscaled logs (Figure 4-25). Default petrophysical modelling workflows i.e. distributing the upscaled logs into the geological model, would result in a reservoir model with reduced heterogeneity (of particular importance, horizontal permeability), tortuosity and subsequently unreasonable profiles. Defining the porosity model distribution in Data Analysis has been used to preserve the heterogeneity (petrophysical range) seen in the well data.

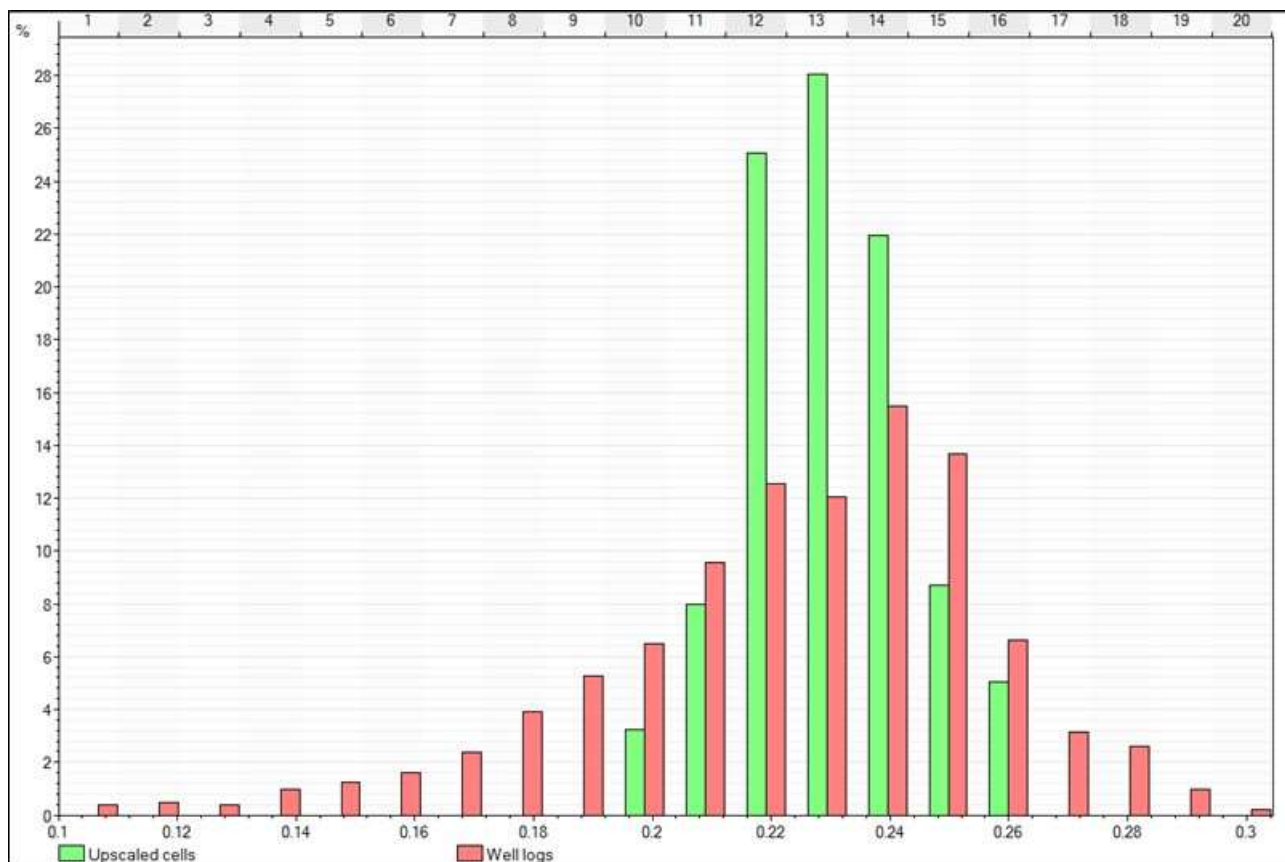


Figure 4-25 Histogram of the Karish-1 net total porosity.

Figure Notes: At Well Log scale (red bars) and upscaled into the geological model (green bars). Upon upscaling (averaging) that all values converge around the mode of the distribution resulting in a dramatic reduced range of porosity values and loss of reservoir heterogeneity

4.5.1.3 Data Analysis

Data Analysis for the net effective and net total porosity models consisted of defining the distribution for the normal score transform for the net sand facies (Facies Code 0) per zone. Importantly the distributions were set to match the porosity range, mode and distribution of the input data at well logs scale, rather than the default upscaled logs (Figure 4-26). This ensures that the resulting effective and total porosity models are entirely consistent with the observed porosity in the input dataset and are not homogenous due to the significant upscaling of a single well.

4.5.1.4 Net Total Porosity Property

The property modelling for net total porosity was carried out for both Karish and Tanin using Gaussian Random Function Simulation, using the same variogram settings and seed points as the facies models, resulting in a net total porosity model that is entirely consistent with the facies model. For the Karish model which heavily utilised the mapped reservoir unit isochores the net total porosity model is also consistent with the interpreted sandstone fairways (reservoir sand distribution) (Section 4.4.3.3). The porosity values for non-net facies (Facies Codes 1 & 2) were set as zero. The average net total porosity distribution is shown in Figure 4-27 to Figure 4-31.

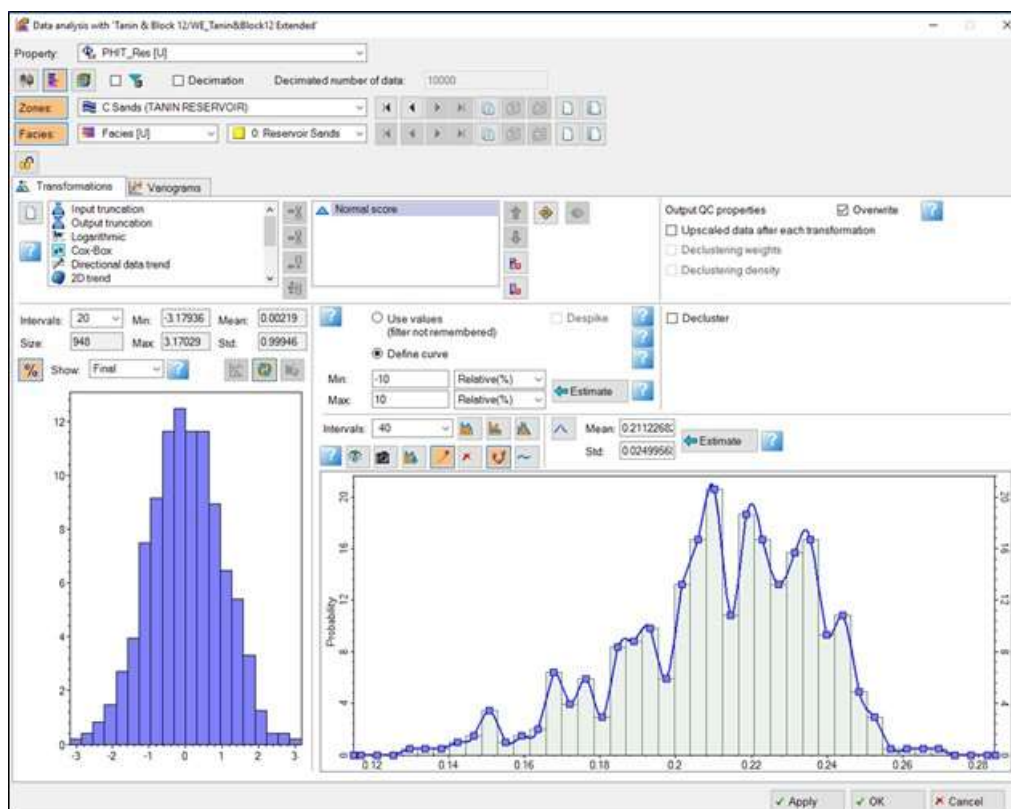


Figure 4-26 Data Analysis setting

Figure Note: Used to introduce heterogeneity back into the geological model by defining the distribution of the output 3D porosity model based on well log scale data. This rectifies the issues 1) sparse data and 2) coarse gridding (Section 4.5.1.2)

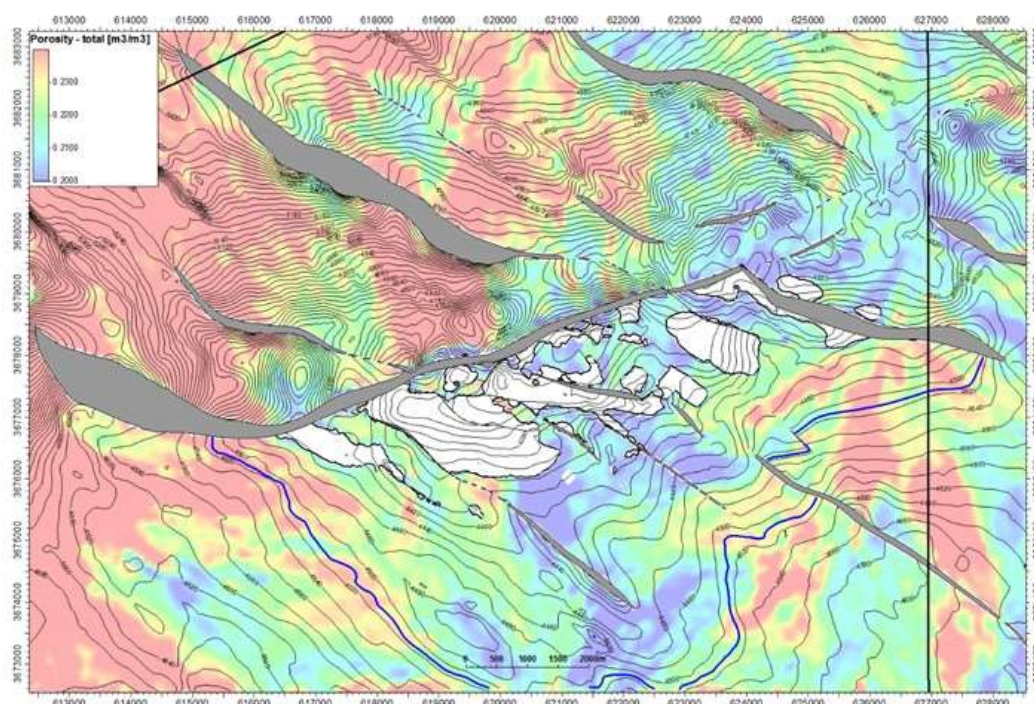


Figure 4-27 Karish Reference Case Geological Model, Mean net total porosity: A Sands.

Figure Note: Consistent with Facies Model (Figure 4-20)

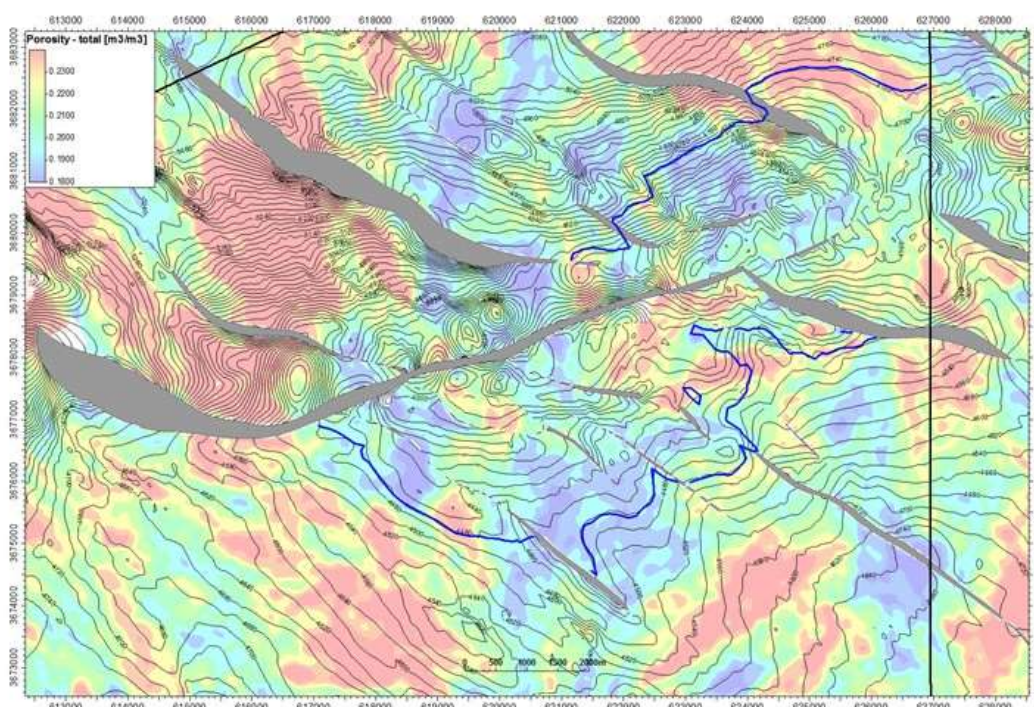


Figure 4-28 Karish Reference Case Geological Model, Mean net total porosity: B Sands.

Figure Note: Consistent with Facies Model

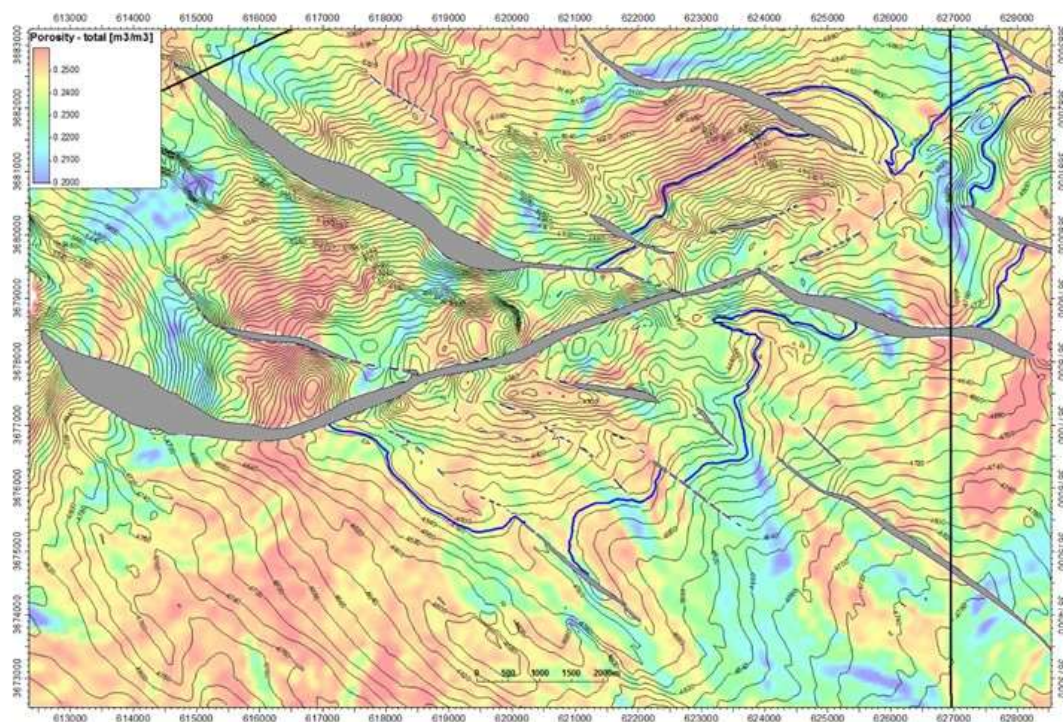


Figure 4-29 Karish Reference Case Geological Model. Mean net total porosity: Upper C Sands.

Figure Note: Consistent with Facies Model (Figure 4-22)

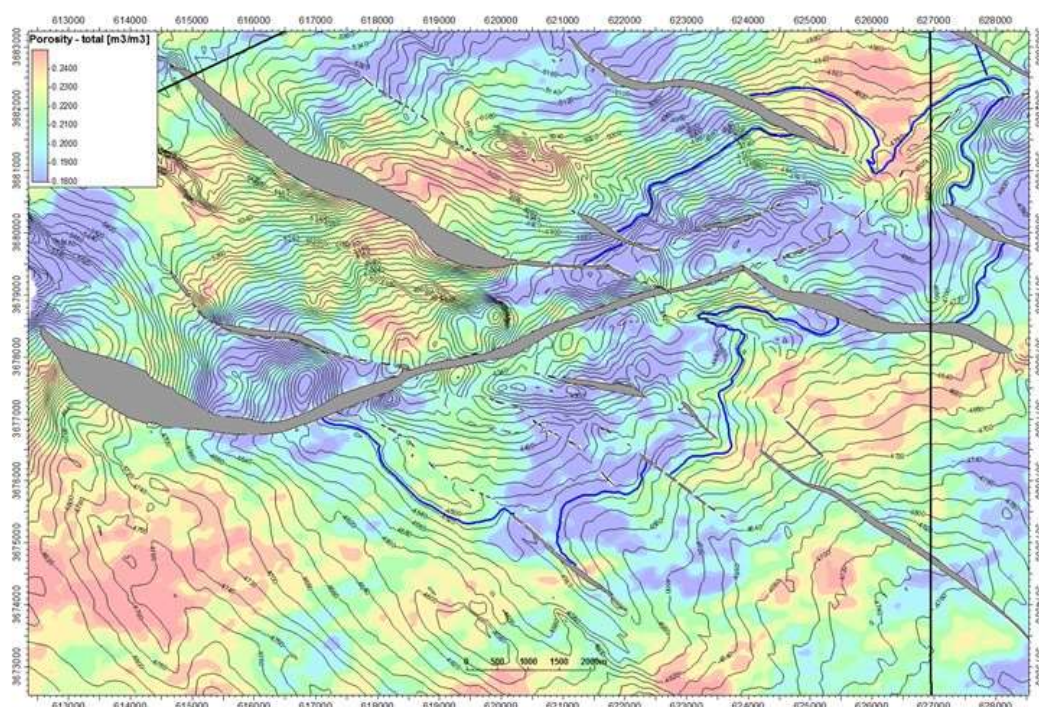


Figure 4-30 Karish Reference Geological Model, Mean net total porosity: Lower C Sand.

Figure Note: Consistent with Facies Model (Figure 4-23)

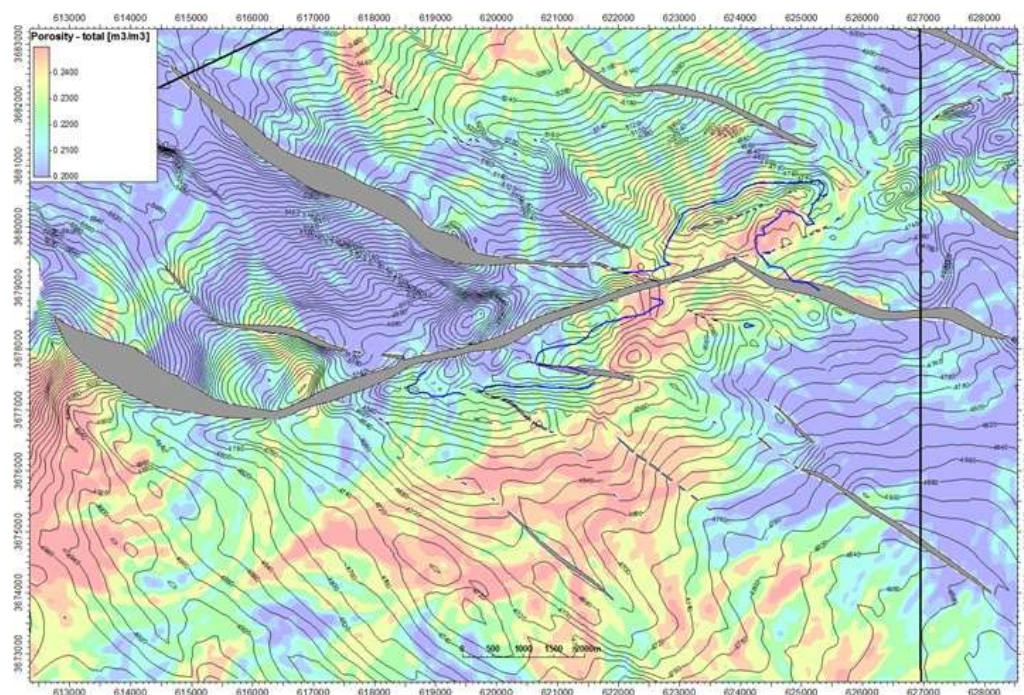


Figure 4-31 Karish Reference Case Geological Model, Mean net total porosity: D3 Sands.

Figure Note: Consistent with Facies Model (Figure 4-24)

4.5.1.5 Net Effective Porosity Petrophysical Property

The net effective porosity model was generated in the same way as the total porosity model (Section 4.5.1.4), but with the additional step of cokriging the effective porosity values against the existing total porosity property. The correlation coefficient between total and effective porosity was set at 0.73 to reflect the fact that there is not a linear relationship between the two properties. The correlation coefficient was derived from a cross-plot of calculated PHIE and PHIT (Figure 4-32).

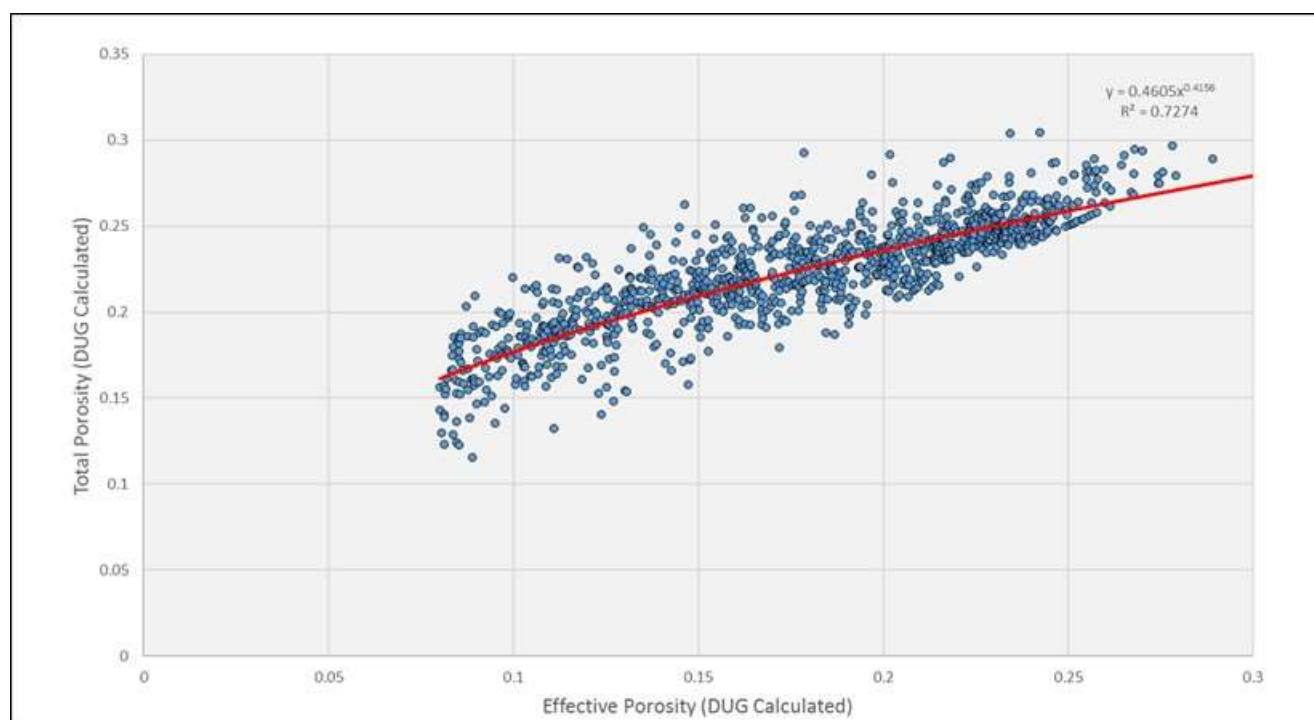


Figure 4-32 Crossplot of net PHIT and net PHIE.

Figure Notes: used to obtain correlation coefficient used in the construction of the net effective porosity model

4.5.2 Permeability Model

The Karish and Tanin geological models both utilise the same KPhi transform. The transform is used for net reservoir sands in all reservoir units.

Due to nature of the acquisition (percussion sidewall cores), caution must be taken when using poroperm data, with significant fracturing of most core plugs noted. Karish-1 has a good agreement of core porosity and calculated total porosity. The match for Tanin-1 is poor with core porosity being significantly greater than PHIT (Figure 4-33).

Ambient total porosity and horizontal air permeability data from Tanin-1 and Karish-1 appear to be in very good agreement and fit to a trend (Figure 4-34), with the exception of the lower porosity classes (<20% core porosity). Only one of these sidewall cores is taken from net reservoir (sand stringer at base of AB shale –which has significantly higher clay content (10-15%) than any of the other sandstone sidewall cores (<4% clay).

No overburden correction has been used to correct for ambient test conditions. A generic 0.7 had been considered but given the uncertainty on the Routine Core Analysis data (percussion acquisition) it was felt that permeability uncertainty is best handled using multiplier in simulator.

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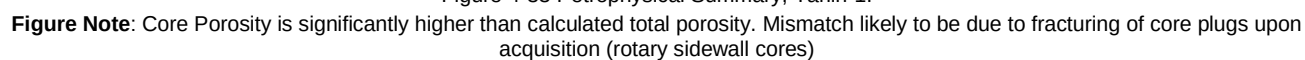
No Klinkenberg correction has been used given the reservoir quality, gas slippage in the high quality Tamar sands is considered minimal.

The resulting permeability for net reservoir sands is given as:

$$K_h = 3.73726e-9 \cdot (PHIT \cdot 100)^{7.72617}$$

This transform has been applied directly to the net total porosity model (non-net facies assigned zero permeability) using the property calculator. Application of the KPhi transform to the PHIT log and collocated cokriging against the porosity model was considered to preserve extreme permeability values. Given the uncertainty in the porosity and permeability values data from the routine core analysis of the percussion sidewall cores, this approach was not adopted as it typically adds significant time to any simulation runs, and can only be supported where there is a high degree of confidence in the core data.

Whilst the absolute value of permeability of the Tamar sands remains uncertain, a mean of 160mD is consistent with the RCI mobility obtained from both Tanin-1 and Karish-1. Furthermore the S_{xo} curves (DUG) show a significant invasion profile (Figure 4-35), as does the delta between the deep and shallow resistivity profiles (Figure 4-36) suggesting a highly permeable reservoir. The uncertainty in the absolute values of the high permeability reservoir have been tested a sensitivity in the dynamic model (Section 6).



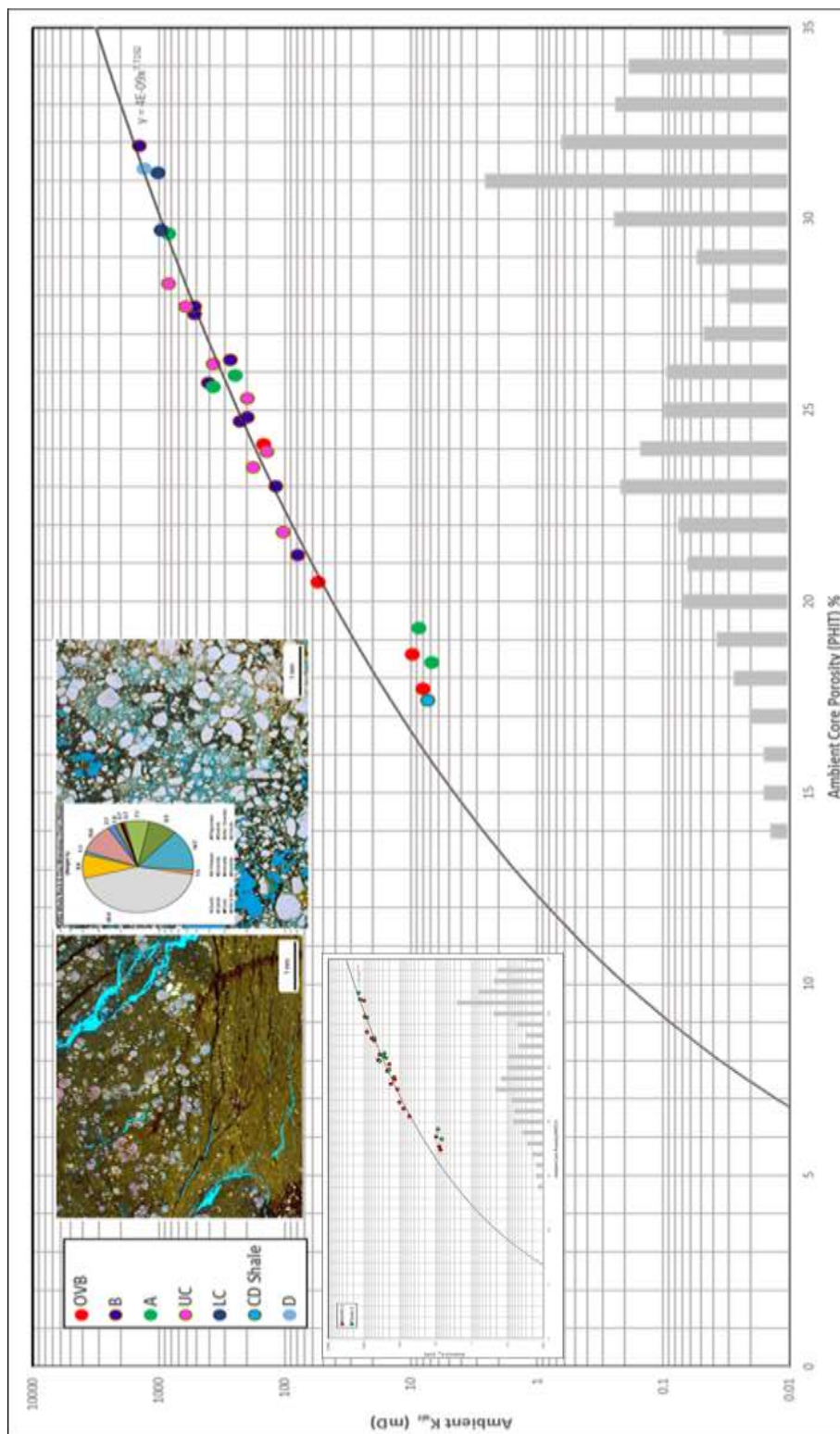


Figure 4-34 Ambient Routine Core Analysis k_n and PHIT data used to derive KPhi transform.

Figure Notes: Inset 1: Data colour coded by well (Karish-1 = Red, Tanin-1 = Green), Inset 2: Example thin section from high porosity low perm core plug showing fracturing of mudstone sample. Inset 3: The only sandstone plug from the low perm/high porosity cluster – petrographic analysis shows this plug to be anomalously clay-rich (green portion of pie chart). Cluster of 5 low perm/high porosity core plugs have been omitted from the derivation of the KPhi transform



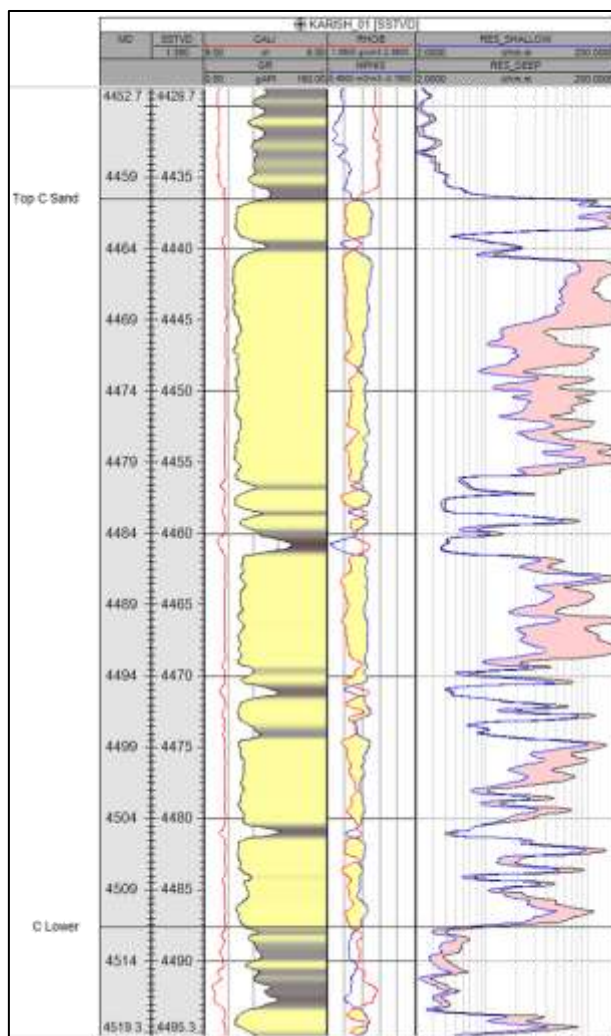


Figure 4-36 Karish-1 C sand Evidence of significant formation invasion

Figure Notes: Third track displays deep (black curve) and shallow resistivity (blue curve) plotted at the same scale. Large mismatch in resistivity, particularly over clean sand intervals would suggest an uneven fluid saturation in the formation i.e. invasion of WBM being evident on the shallow resistivity

4.5.3 Water Saturation Model

4.5.3.1 Methodology

The Karish water saturation has been modelled using a Saturation Height Function derived using the Cuddy (1993) log based method to derive bulk volume of water (BVW) which does not rely on capillary pressure data as Cuddy et.al suggests that the product of porosity and saturation can be a function of height alone. Neither Karish-1 nor Tanin-1 have any Special Core Analysis data. Cuddy et.al plots BVW versus height above free water level (HAFWL) on log to log scale and the equation has the form:

$$\log (\phi \cdot S_w) = A \cdot \log (h) + B$$

Where A & B are found by regression.

This method is particularly suited to gas reservoirs where reservoir quality is binary as wettability and permeability are not considered and is therefore deemed a reasonable approach for the Tamar sands.

4.5.3.2 Saturation Height Function

Solving for the average porosity class (0.20-0.25) within the C Sands using log derived BVW (Cuddy 1993 – Figure 4-37) yields a reasonable match between calculated and modelled water saturation. S_w is therefore calculated within the C/D Sands using:

$$S_w = ((0.12774 * \text{Exp}(-0.120 * \text{HAFWLm}) + 0.028)) / \text{PHIE}$$

Even within the C Sands, it can be seen that log derived values of BVW are heavily impacted, and therefore unreliable (Figure 4-38), within argillaceous intervals the calculated S_w is affected by the bias of the resistivity tool to the conductive beds (mudstones). Figure 4-37 shows a log derived BVW to suffer within the A/B Sands for this reason. It was therefore decided that the Cuddy transform would be used for the A/B sands but with RCA derived S_w values to avoid the bias within this argillaceous interval. The core plug data (total porosity) was therefore corrected to PHIE before deriving the SHF for the A/B Sand (Figure 4-38).

A/B Sand water saturation was modelled using:

$$S_w = ((0.12774 * \text{Exp}(-0.08118 * \text{HAFWLm}) + 0.045)) / \text{PHIE}$$



Figure 4-37 Log derived BVW and SHF used for the C/D Sands

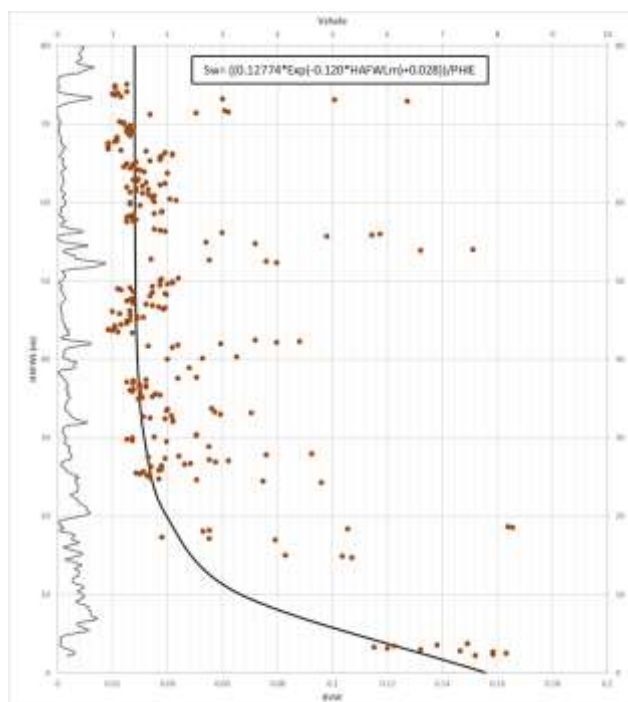


Figure 4-38 Average porosity class BVW for the Karish-1 C Sands

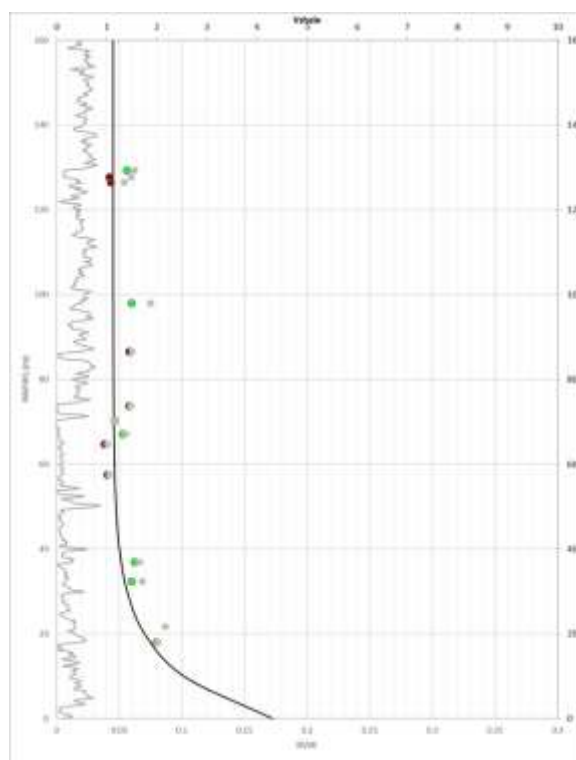


Figure 4-39 SHF derived for A/B sand using RCA.

Figure Notes: Core plug data (grey) corrected to effective porosity (maroon/green points)

4.6 Summary of Reference Case Geological Model

Table 4-10 and Table 4-11 summarise the Gross Rock Volume, petrophysical properties and fluid properties for the Karish and Tanin reference case deterministic geological models.

4.6.1 Karish Reference Case Geological Model

Table 4-10: Karish Complex Reference Case Geological Model Average Petrophysical Properties per structure and per reservoir unit

KARISH MAIN					
	GRV MMm ³	NTG Decimal	Net PHIT Decimal	Net Sgas Decimal	Bg SCM/RCM
A Sands	682	0.22	0.22	0.61	364
B Sands	1418	0.38	0.20	0.60	363
C Sands - Upper	601	0.93	0.24	0.83	357
C Sands - Lower	634	0.50	0.20	0.75	357
D Sands	259	0.65	0.22	0.74	361

KARISH NORTH					
	GRV MMm ³	NTG Decimal	Net PHIT Decimal	Net Sgas Decimal	Bg SCM/RCM
A Sands	-	-	-	-	-
B Sands	866	0.44	0.21	0.64	363
C Sands - Upper	306	0.92	0.25	0.84	357
C Sands - Lower	332	0.55	0.20	0.76	357
D Sands	133	0.68	0.24	0.77	361

KARISH EAST					
	GRV MMm ³	NTG Decimal	Net PHIT Decimal	Net Sgas Decimal	Bg SCM/RCM
A Sands	-	-	-	-	-
B Sands	-	-	-	-	-
C Sands - Upper	201	0.95	0.24	0.82	357
C Sands - Lower	230	0.54	0.20	0.76	357
D Sands	102	0.66	0.24	0.75	361

4.6.2 Tanin Reference Case Geological Model

Table 4-11: Tanin Complex Reference Case Geological Model Average Petrophysical Properties per structure and per reservoir unit

TANIN A					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm ³	Decimal	Decimal	Decimal	SCM/RCM
A Sands	465.6	0.81	0.23	0.70	364
B Sands	149.1	0.66	0.22	0.70	363
TANIN B					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm ³	Decimal	Decimal	Decimal	SCM/RCM
A Sands	73.7	0.84	0.22	0.70	364
B Sands	24.4	0.70	0.21	0.70	363
TANIN C					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm ³	Decimal	Decimal	Decimal	SCM/RCM
A Sands	269.4	0.84	0.23	0.70	364
TANIN D					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm ³	Decimal	Decimal	Decimal	SCM/RCM
A Sands	33.2	0.81	0.23	0.70	364
B Sands	6.3	0.79	0.21	0.70	363
TANIN E					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm ³	Decimal	Decimal	Decimal	SCM/RCM
A Sands	224.3	0.76	0.23	0.70	364
B Sands	135.0	0.61	0.20	0.70	363
TANIN F					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm ³	Decimal	Decimal	Decimal	SCM/RCM
A Sands	192.5	0.85	0.23	0.70	364
B Sands	47.2	0.72	0.20	0.70	363

5 Volumetric Assessment

5.1 Energean In-Place Volumetric Assessment: Karish & Tanin

In place volumes have been calculated on the Karish and Tanin geological model and are presented in Table 5-1 - Table 5-9. Hydrocarbon Pore Thickness maps are presented for the Karish complex in Figure 5-1 and the Tanin complex in Figure 5-2.

5.1.1 Karish Complex

Table 5-1: Karish Main Reference Case Geological Model Volumetric Assessment

KARISH MAIN						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					bcm	bscf
A Sand	682	149	33	20	7.2	255
B Sand	1418	535	109	65	23.7	837
Upper C Sand	601	560	136	113	40.3	1424
Lower C Sand	634	319	65	49	17.4	616
D Sand	259	169	38	28	10.2	362
Total					98.9	3494

Table 5-2: Karish North Reference Case Geological Model Volumetric Assessment

KARISH NORTH						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					bcm	bscf
B Sand	866	382	80	51	18.5	654
Upper C Sand	306	280	69	58	20.8	734
Lower C Sand	332	181	37	28	10.0	353
D Sand	133	91	22	17	6.2	220
Total					55.5	1961

Table 5-3: Karish East Reference Case Geological Model Volumetric Assessment

KARISH EAST						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					bcm	bscf
Upper C Sand	201	190	45	37	13.2	467
Lower C Sand	230	124	25	19	6.7	238
D Sand	102	67	16	12	4.2	150
Total					24.2	855

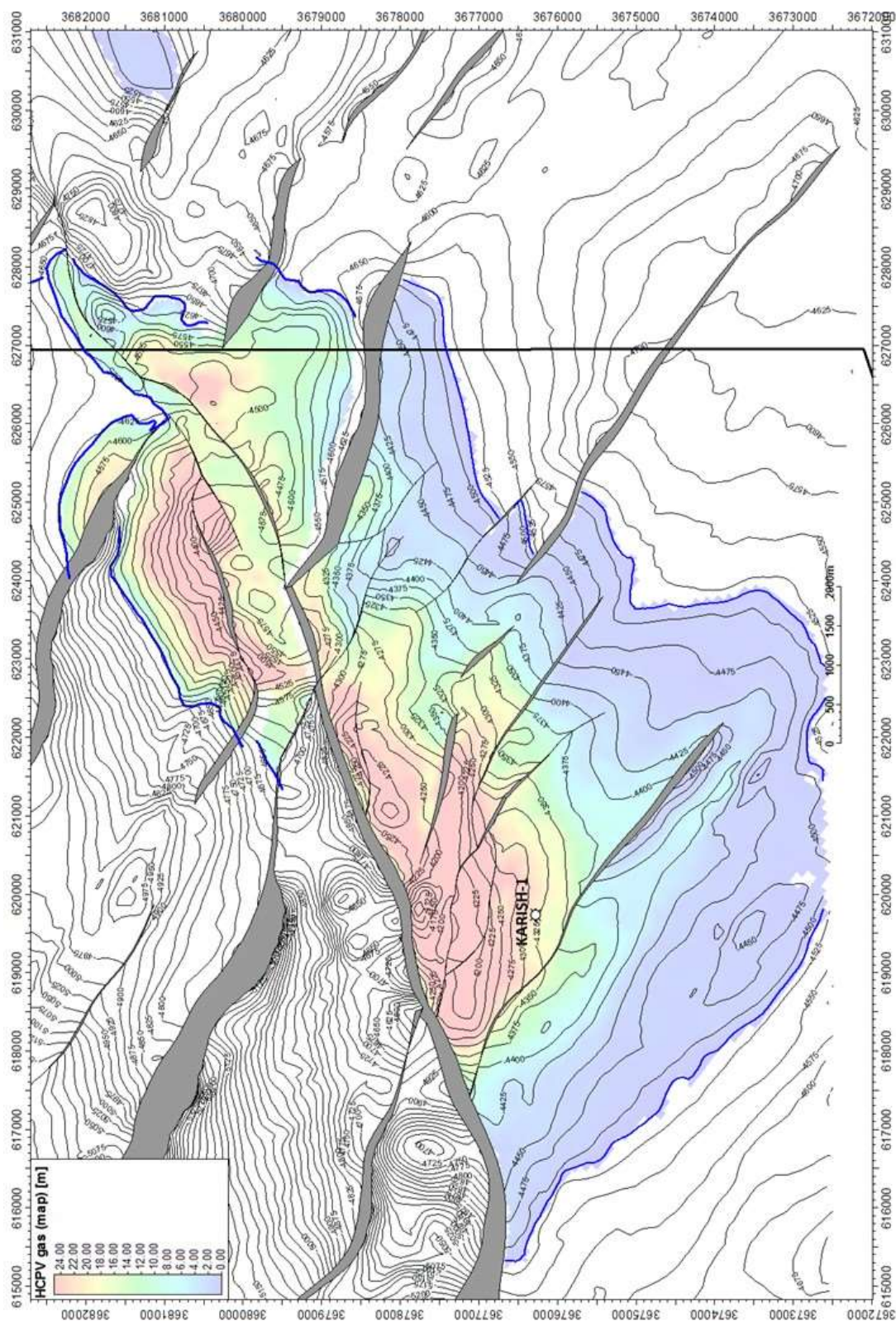


Figure 5-1 Karish Complex Hydrocarbon Pore Thickness Map (m).

Figure Note: Reference Case Geological Model with Top A Depth Contours

5.1.2 Tanin Complex

Table 5-4: Tanin A Reference Case Geological Model Volumetric Assessment

TANIN A						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					MMm ³	bscf
A Sand	466	379	88	60	22.3	787
B Sand	149	102	22	14	5.3	186
Total					27.5	973

Table 5-5: Tanin B Reference Case Geological Model Volumetric Assessment

TANIN B						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					MMm ³	bscf
A Sand	72	60	13	9	3.5	124
B Sand	23	16	3	2	0.9	31
Total					4.4	155

Table 5-6: Tanin C Reference Case Geological Model Volumetric Assessment

TANIN C						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					MMm ³	bscf
A Sand	264	221	51	35	13.3	469
Total					13.3	469

Table 5-7: Tanin D Reference Case Geological Model Volumetric Assessment

TANIN D						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					MMm ³	bscf
A Sand	32	26	6	4	1.6	57
B Sand	6	5	1	1	0.3	9
Total					1.9	66

Table 5-8: Tanin E Reference Case Geological Model Volumetric Assessment

TANIN E						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV (MMm ³)	GIIP (MMm ³)	
					MMm ³	bscf
A Sand	218	167	38	27	10.0	353
B Sand	127	78	16	11	4.1	146
Total					14.1	499

Table 5-9: Tanin F Reference Case Geological Model Volumetric Assessment

TANIN F						
	GRV (MMm ³)	Net Volume (MMm ³)	Pore Volume (MMm ³)	Hydrocarbon PV(MMm ³)	GIIP (MMm3)	
					MMm ³	bscf
A Sand	187	159	36	26	9.6	338
B Sand	45	34	7	5	1.8	65
Total					11.4	403

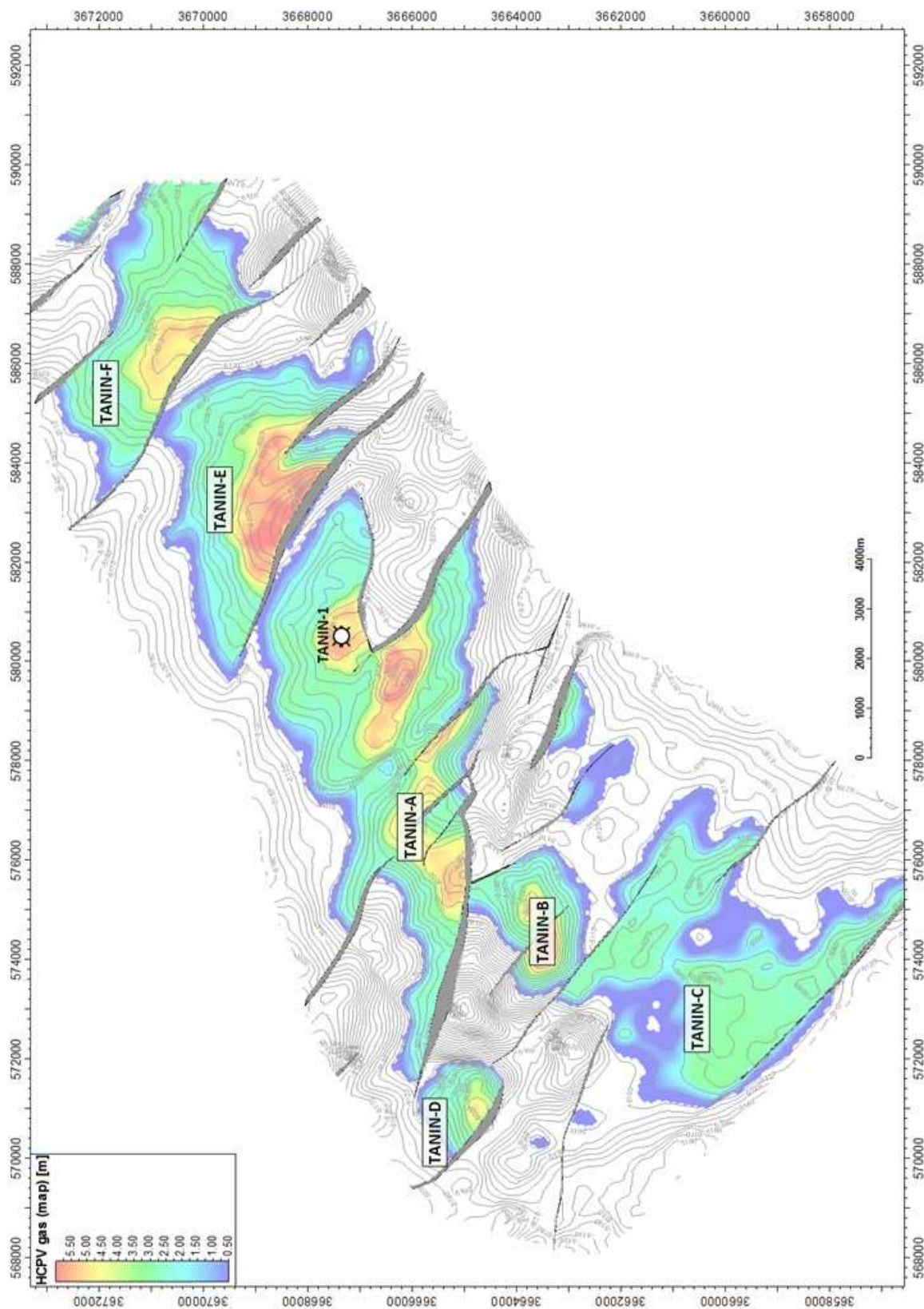


Figure 5-2 Tanin Complex Hydrocarbon Pore Thickness Map (m).

Figure Note: Reference Case Geological Model with Top A Depth Contours

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5.2 Energean In-Place Volumetric Assessment: Probabilistic Range

5.2.1 Methodology

A probabilistic range of geological models has been constructed for both the Karish and Tanin complex to determine the range of in place volumes within each structure of the respective complexes.

The models were constructed using the Petrel 2016 workflow manager to write a probabilistic workflow. Some 500 realisations of the Karish and Tanin complexes were run. This has the advantage over conventional Monte Carlo simulation that any given outcome can be reconstructed, inspected and simulated if required. It also allows the areal distribution of Hydrocarbon Pore Volume to be determined which has many advantages for development well planning.

5.2.2 Karish Input Parameters

5.2.2.1 Gross Rock Volume

The uncertainty in gross rock volume is difficult to quantify given a single well (Karish-1) on the Karish Main structure. Statistical analysis of variations in the seismic velocities are not possible with a single penetration of the overburden and the nearest offset well for which the Operator has data being the Tanin-1 (40km). The approach adopted for the purpose of probabilistic modelling was to assume an error of +/- 10% GRV, with the GRV error for each iteration (realisation) being the same for each reservoir interval. This assumes that the relative thickness variation between individual reservoir units is not an uncertainty. Given the excellent seismic data quality, the excellent match to synthetics and the detailed interpretation of intra-reservoir reflectors, this is a reasonable assumption.

Due to the complex structural model for Karish, the Gross Rock Volume uncertainty has been captured as a pore volume multiplier.

5.2.2.2 Porosity

Two parameters have been set for the uncertainty in porosity: 1) the uncertainty in the calculation of porosity and 2) the uncertainty in the average net total porosity away from Karish-1.

Given the significant gas effect on the neutron porosity log, particularly over clean gas bearing sandstones, both the methodology and the net pay cut-offs are uncertain. Down Under Geosolutions carried out a sensitivity analysis on the uncertainty in the calculation of porosity (Section 3.6.4.7) which showed the uncertainty to be +/- 1.8 p.u. on average for all reservoir units, which was applied in the probabilistic workflow. Whilst it could be argued that statistics are available for each individual reservoir unit, and there a porosity uncertainty per unit could be applied, the model has 10 zones, of which 5 contain net reservoir. Varying a single parameter (uncertainty in the calculation of porosity) multiple times results in a convergence around the mode, with the mode assumption being zero. Detailing a parameter multiple times therefore fails to capture the true range of uncertainty within the reservoir. The uncertainty range was applied as a uniform distribution given all methods of calculating average porosity in the sensitivity analysis (Section 3.6.4.7) are valid.

Capturing the uncertainty in the average net total porosity away from Karish-1 i.e. how representative the reservoir is away from the point of well control was modelled as a separate parameter, which is independent of the accuracy in the petrophysical calculation of net total porosity. The range of uncertainty modelled was +/- 1.5 p.u. with a uniform distribution. The range of uncertainty was determined using geostatistical bootstrapping of the Karish-1 and Tanin-1 wells to test the dependency of the average porosity on the sample interval. The determined range may be considered small given only a single penetration of each structure, but given the depositional environment and therefore expected continuity of petrophysical parameter across the AOI this is not unreasonable. Furthermore, it is important to note that the modelling attempts to capture the range of

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average net porosity values in determining the pore volume uncertainty and *not* the absolute range of porosity. With a large dataset i.e. more wells, a normal distribution would have been used to capture the uncertainty, as a significant sample of the reservoir would give confidence that the reservoir has been adequately sampled. With a single well on a 51km² closure, a uniform distribution is more reasonable.

5.2.2.3 Net-to-Gross

The NTG of all units, with the exception of the B sand, have been modelled as a min/max of +/-10% with a mean of zero and one standard deviation of 5%. Given the depositional environment (mod/outer submarine fan lobe deposits), continuity in both facies and petrophysical properties can be reasonably expected over the Karish AOI. A range of +/-10% was therefore deemed appropriate.

The exception to this range is the B Sand where a wider range is modelled. The B sands in Karish-1 are thinly bedded making the calculation of net pay problematic (Section 3.5.5.7). Using conventional log analysis, a NTG of 12% can be determined. Using thin bed analysis based on the image log, a NTG can be determined, whilst using the same petrophysical cut-off as the other reservoir units (PHIE>0.08, Vshale<0.5) with any gas saturation term yields a NTG of 44%. 44% has therefore been used as maximum, 12% as a minimum and 20% as the mean with a truncated normal distribution.

5.2.2.4 Water Saturation

Section 4.5.3.2 describes the methodology used for deriving the Saturation Height Function for the Karish and Tanin geological models. Using log (calculated Sw) derived Cuddy BVW results in a more optimistic water saturation than using routine core analysis sw as the input. In order to capture the uncertainty in Sw in all reservoir units, a continuous random distribution between the two SHFs has been used to model uncertainty.

5.2.2.5 Gas Water Contact

No uncertainty in the GWC has been modelled for Karish main, owing to excellent formation pressure data giving confidence in the depth of the FWL, in combination with RCI samples and resistivity data which are in excellent agreement with the interpretation of a GWC at -4512m TVDSS.

Karish North and East are expected to share a common GWC due to reservoir-reservoir juxtaposition across the bounding fault. The depth of the GWC is derived from seismic (PSDM) depth, with an uncertainty of +/-10m. An equiprobable distribution between these end members has been assumed for the purpose of Monte Carlo simulation.

5.2.3 Tanin Input Parameters

The same input parameters were assuming for Tanin, but with the exception of the B Sand NTG being the modelled in line with the Karish C/D sands NTG i.e. min/max of +/-10% with a mean of zero and one standard deviation of 5%. The B Sands at Tanin were not constrained by a bathymetric high in the same way as at Karish, which is evident from the massive clean sand deposit intersected in Tanin-1, and are not subject to the same thin bedding and associated uncertainty as the Tamar sands in Karish-1.

An uncertainty of 5m was assumed, with an equiprobable distribution to reflect the very small uncertainty in the formation pressure data (Section 4.3.5.3).

5.2.4 Probabilistic In-Place Volume

5.2.4.1 Karish Complex

The GIIP range of for each of the Karish Complex structures in presented in Figure 5-3. The GIIP range for the main producing reservoir intervals (C and D Sands) in Karish Main is given in Figure 5-4.

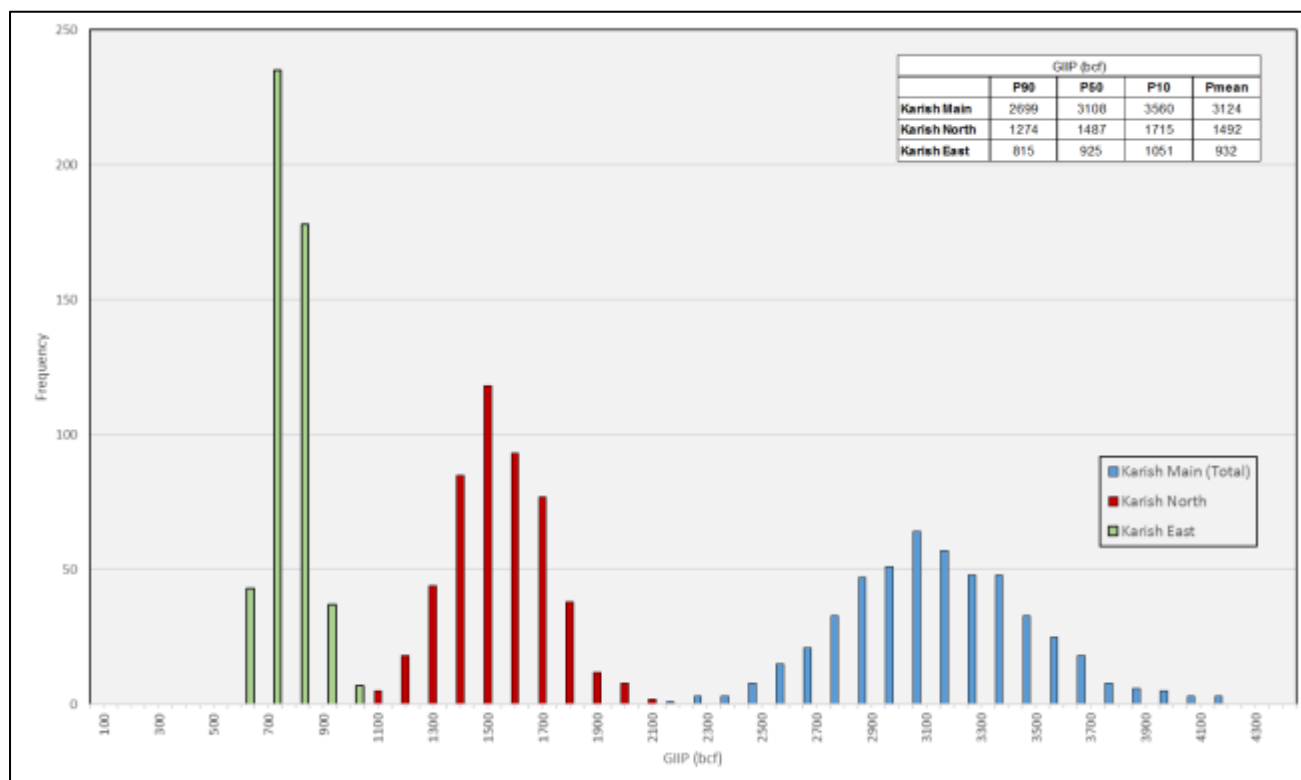


Figure 5-3 GIIP Range resulting from Monte Carlo simulation.

Figure Notes: Karish Main, Karish North and Karish East – all reservoir units

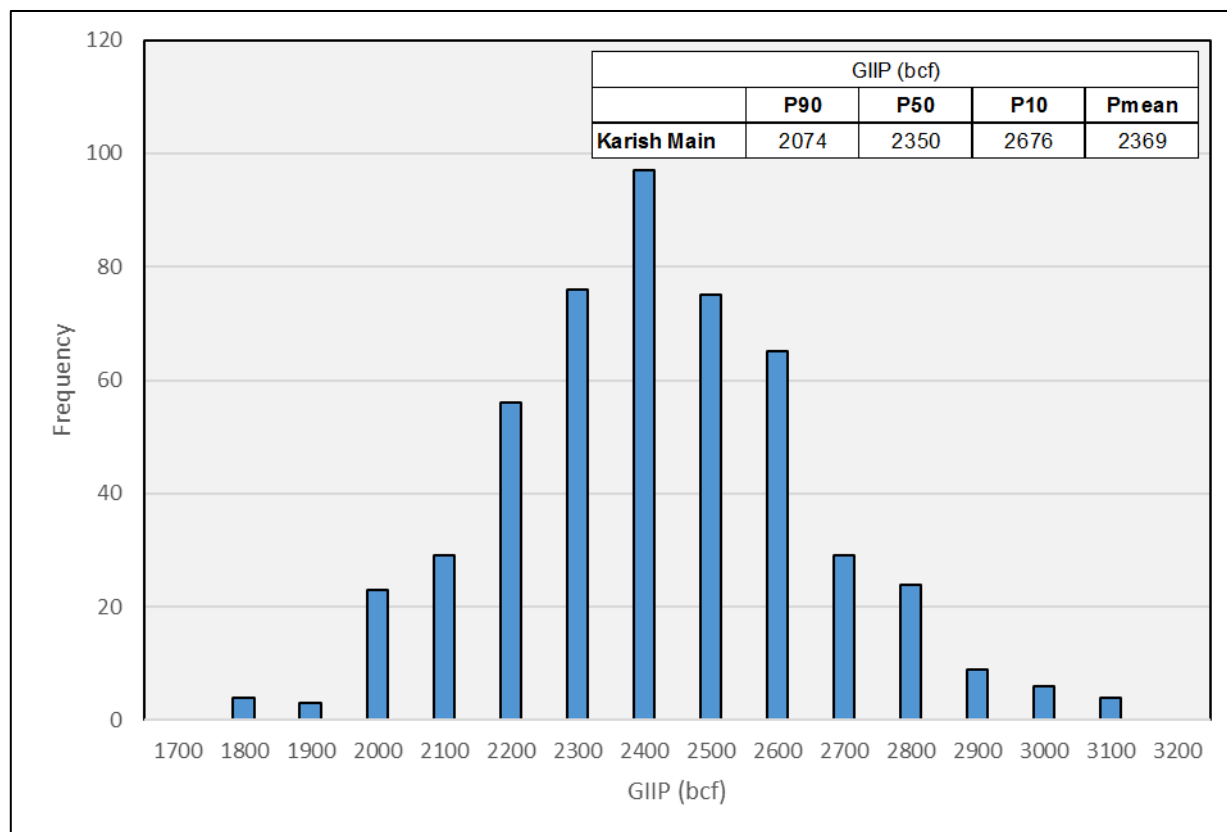


Figure 5-4 Monte Carlo generated GIIP range for Karish Main C/D Sands

The volumetric range determined for the Karish complex is consistent with the reference case geological model, with all units/structures being very close to the deterministic in-place volumes, with the exception of the B Sand.

The reference case geological model uses the same net pay cut-off as the other reservoir intervals i.e. clean C/D sands. Given the outstanding reservoir quality sands, in what is deemed to be a binary sand/shale system, no water saturation term is used in the net pay cut-off. As a result a NTG of 0.44 is modelled in the B Sands. In the probabilistic (Monte Carlo) simulation, the thin bedded nature of the B Sands has been addressed, with the deterministic 0.44 being considered a high side end member (Section 5.2.2.3). As such, the deterministically generated GIIP value of 837bcf is a P02 (Figure 5-5).

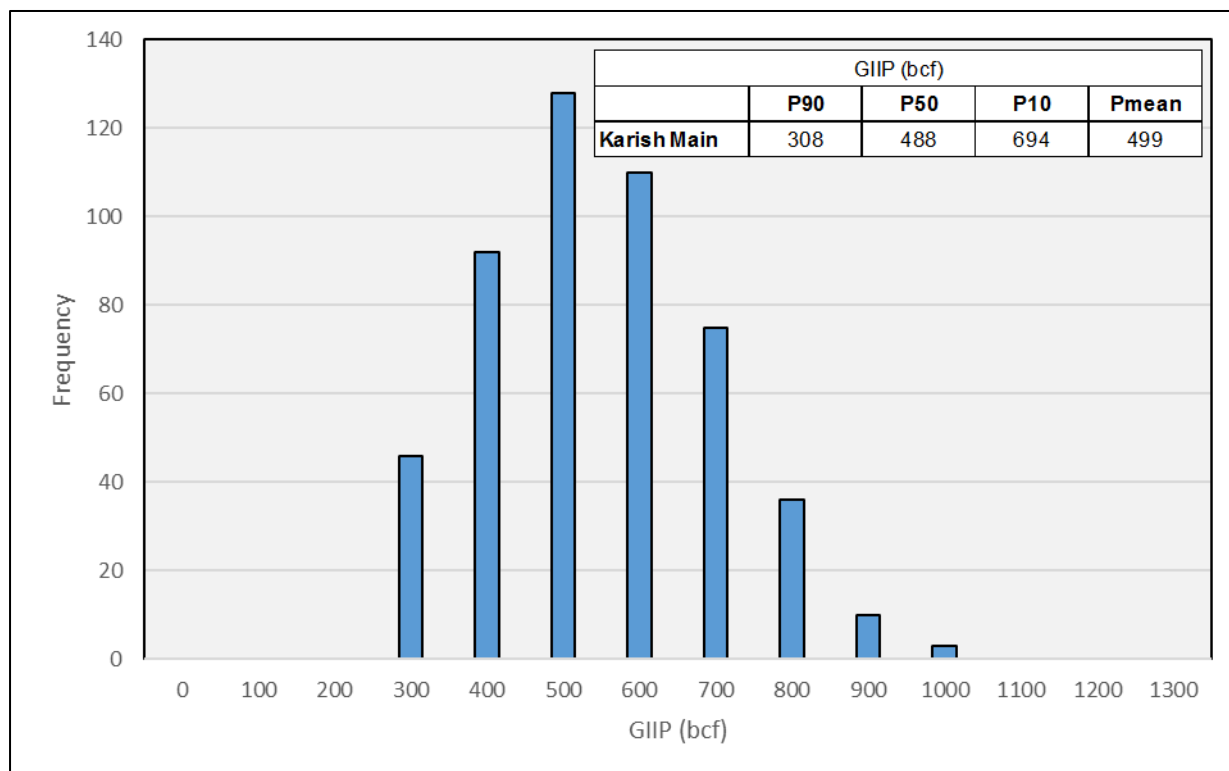


Figure 5-5 Probabilistic GIIP Range for B Sands, Karish Main

5.2.4.2 Tanin Complex

Volumetric were run for all structures within the Tanin complex. The distribution of GIIP for each structure (Tanin A – Tanin F (Figure 4-5)) is given in Figure 5-6, with the total Tanin Lease GIIP given in Figure 5-7. Tanin A-C form a continuous accumulation, with these volumes being presented in Figure 5-8.

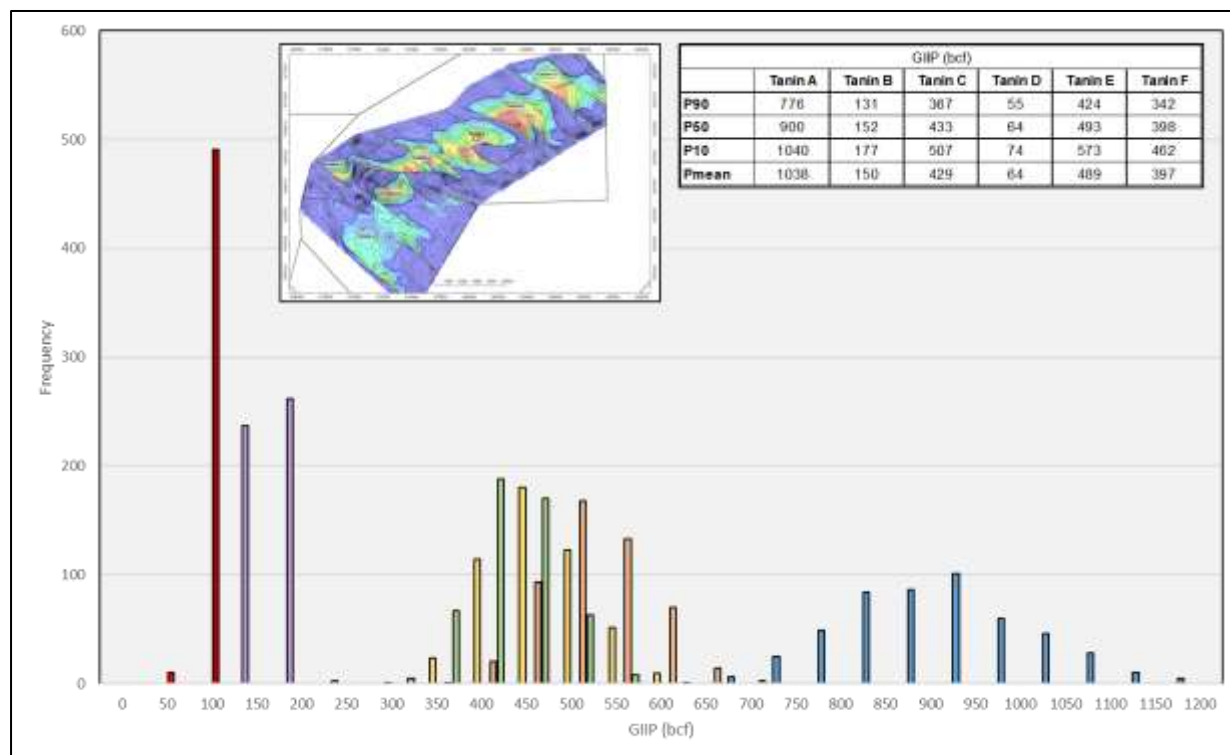


Figure 5-6 Tanin Complex GIIP range by Structure

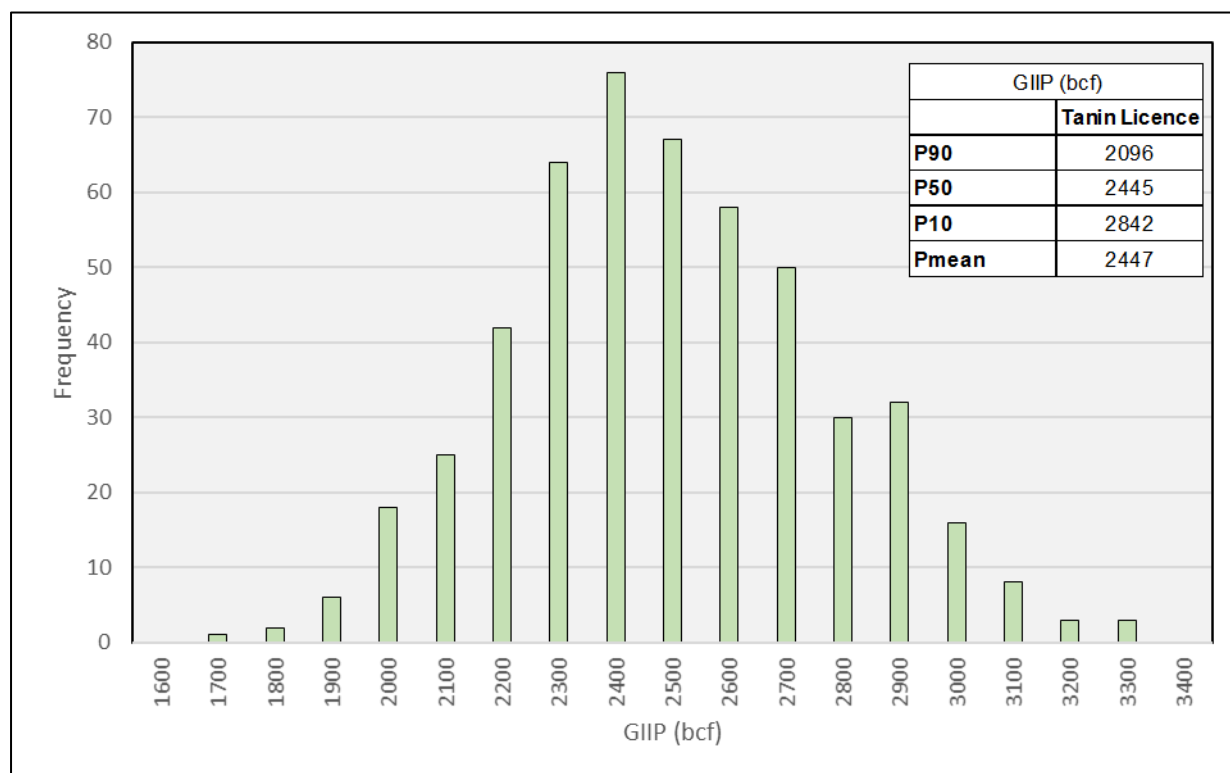


Figure 5-7 GIIP Range for Tanin Lease, All structures, All reservoir units

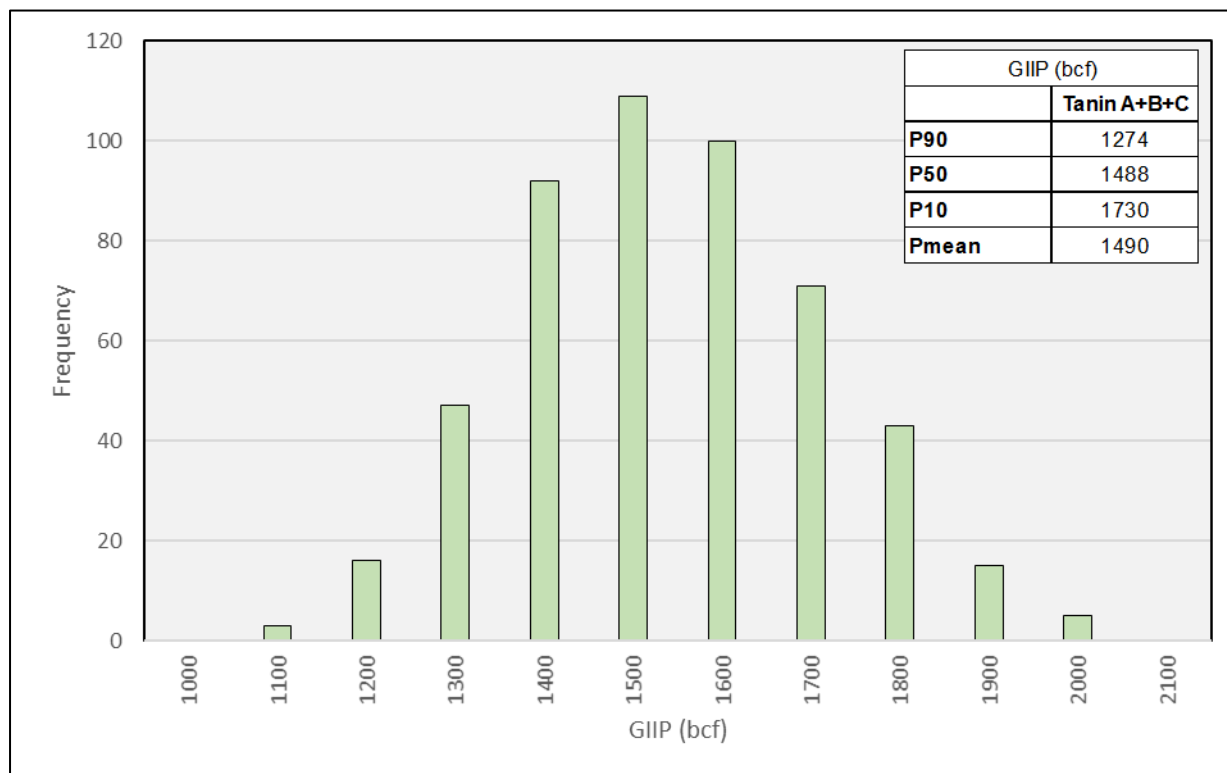


Figure 5-8 Tanin A-B-C GIIP Range, all reservoir units

5.3 Comparison with NSAI CPR volumetric Assessment

The Operator engaged Netherland, Sewell and Associates, Inc. (NSAI) in early 2017 to complete a Competent Person's Report (CPR) for the purpose of estimating the unrisked Contingent and Prospective resources as of 31st December 2016.

Energean and NSAI are broadly in agreement with NSAI for Karish Main and its associated prospects (Karish North and Karish East), with NSAI giving a very modest increase in GIIP (17 bscf). The main departure in volumes is within the thinly bedded B Sands, where NSAI carry a lower P90/50/10 than Energean, owing to NSAI being cautious on thinly bedded reservoirs, citing examples of multiple reserves write-downs based on poor reservoir performance. Energean do not have the same reservations about the producibility of this reservoir interval, owing to the excellent quality of the net sands logged conventionally within the B Sands, the presence of >0.2 NTG based on image log analysis, the significant sub seismic faulting expected which would serve to offset any B Sand laminations in combination with a very mobile hydrocarbon phase. Energean intends to collect core and high definition logs over the Karish B sands when drilling the three planned development wells. Furthermore it is planned to address any uncertainty in the connectivity of the B Sands by installing downhole pressure gauges in the Karish Main production wells with continuous reporting at surface.

NSAI also carry a smaller (400 bscf) best technical GIIP for the Tanin A, B and C accumulations, predominantly due to a lower GRV than Energean, with NSAI utilising existing depth maps received from the previous Operator for the 2015 CPR. Energean have updated the Top Tamar sands depth map (as described in this FDP) which has been used to calculate the stated GIIPs. These new maps have not yet been reviewed by NSAI and hence incorporated in their analysis. Furthermore, NSAI use a very aggressive geometrical factor, resulting in an

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average gross A Sand vertical thickness of 16.5m which, in Energean's view, is not supportable given the low structural relief on the Tanin structure. These issues will be addressed with NSAI in parallel with the next development phase and before FID when the CPR will be updated and the Contingent Resources turned into Reserves.

6 Reservoir Engineering

6.1 Karish and Tanin Reservoir Simulation Models

A best-technical case reservoir simulation model was built for the Karish Main field and a separate model was built for the Tanin fields, using Eclipse 100 software. The areal extent, structure and rock properties of porosity, permeability and net to gross were input from the geological model built for each field using Petrel. Details of these models are given in Section 4.6.

The general work flow adopted in the dynamic modelling exercise for both fields consists of the integration of the static geological model with the reservoir fluids and their predicted rel-perm behaviour, the fluid distribution by rock property and height above the contact, the rock-elasticity and any production facility limitations. Once integrated this allows for the evaluation of the dynamic reservoir performance under a set of selected constraints such as tubing head pressure, maximum gas production rate and liquid rates of the field in order to honour the production facilities design. Figure 6-1 shows a general work flow to build a simulation model.

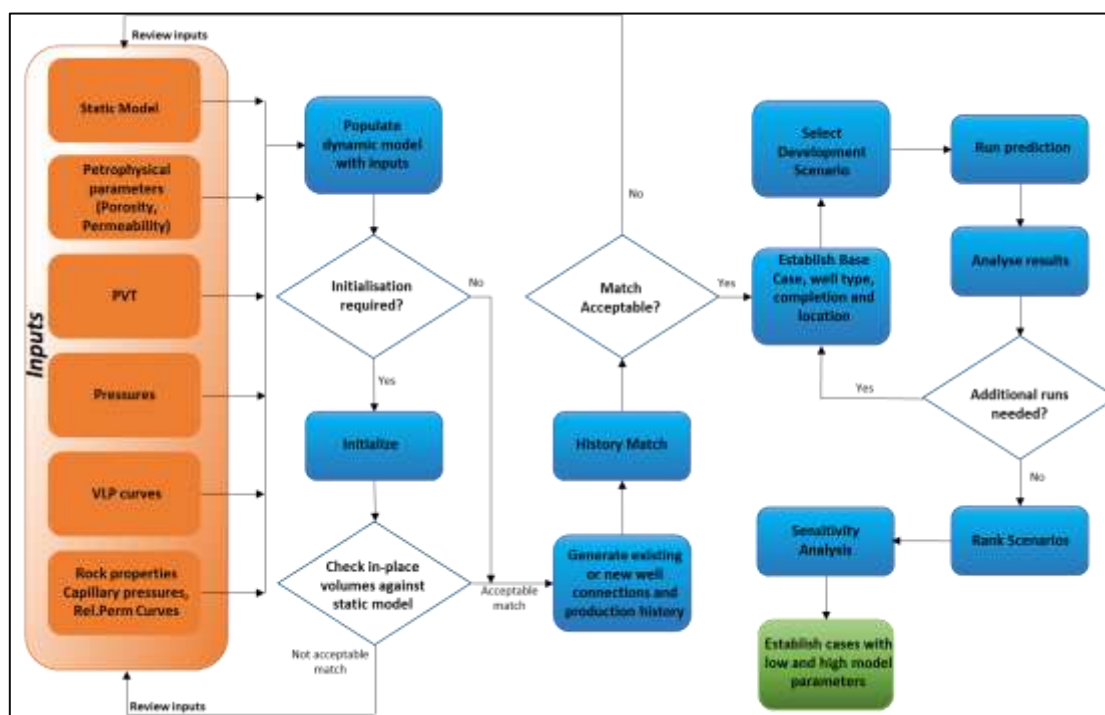


Figure 6-1 Example of general Dynamic Simulation Model Construction and Execution Workflow

Karish and Tanin are lean gas fields: the simulator used in this exercise was Eclipse 100 (fully implicit), with black oil simulation adopted assuming that the reservoir pressure is far from the critical point and does not drop to the dew point, so vaporized oil concentration remains fixed. This is a result of the predicted strong aquifer that keeps reservoir pressure above dew point during the entire field production life.

The Karish and Tanin dynamic models were established as a 3D, 2-phase models (gas and water) system with a single PVT description and two sets of relative permeability tables according to the rock quality of each zone. Two different fluid contacts and equilibrium regions were specified to reflect the Karish Main discovered volumes and the Karish North & East undiscovered prospect volumes, inferred from seismic DHI's.

Model initialisation was performed through equilibration with the two discrete gas-water contacts. The Tanin model was initialised declaring one single gas water contact and one equilibrium region. Initial gas volumes in

place on the dynamic models matched with the figures reported in the static model with differences below to 1%.

The Karish model is configured in a black oil (dry gas) format with a Fetkovich numerical aquifer and comprised the following properties and dimensions as shown in Table 6-1.

Table 6-1: Karish Grid determination

	KARISH GRID DIMENSION	TANIN GRID DIMENSION
Model type	Black Oil: Gas, Water	Black Oil: Gas, Water
Dimensions	99 x 147 x 85	111 x 146 x 52
Total No. of cells	1237005	842712
Active cells	463294	809936
Cell height (m)	6.00	2.0
Cell X length (m)	100	100
Cell Y length (m)	100	100

The field geometry is modelled using corner-point geometry, while the gas water contacts (GWC) were set at 4512 m TVDss in Karish Main taken from the exploration well (Karish-1) log data and 4774 m TVDss in the region of Karish South and Karish East estimated from the cut-off of the DHI. Tanin GWC was set at 5095 m TVDss estimated from Tanin-1 MDT lof.

Both ECLIPSE models are built in metric units as input and field units as output. The main properties of the dynamic model used in the simulation are as summarised below.

6.1.1 Rock Property Data

6.1.1.1 Sand Connectivity

A juxtaposition analysis was carried out for all modelled faults by building Allan Diagrams (Allan, 1989). The analysis shows that the identified gas-water contact is in the sand-sand juxtapositions in parts along the fault planes. Based on this observation, cross-fault fluid flow should be controlled by the sealing potential of the faults.

The distribution of the phyllosilicate content, or volume of shale (V_{sh}), is the key factor in defining the sealing potential of the faults (Knipe et al., 1997) as it relates to the shale gouge fraction present in the fault-rocks. Using this concept, Yielding et al. (1997) introduced the Shale Gouge Ratio (SGR) to estimate the clay content in a fault from the mixing of sediments with different shale contents in the throw interval. SGR values less than 20% or 0.2 are typically associated with cata-clastic fault-rock and sealing of the fault is considered unlikely. Higher SGR values correspond to greater fault seal potential. For SGR >40% a fault is associated mainly with clay smears, and therefore regarded as a likely sealing fault.

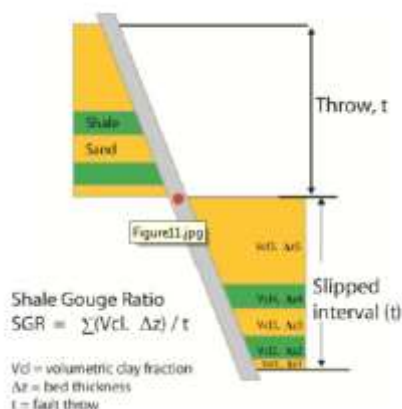


Figure 6-2 Schematic diagram showing the definition of Shale Gouge Ratio (SGR)

Figure Notes: After Yielding et al. (1997). At any point on the fault plane, the SGR equals the clay content of the throw interval (t) that has slipped past that point

In the present study, SGR was calculated for all modelled faults, using the corresponding V_{sh} log from the Karish-1 well. The V_{sh} log was up-scaled using an arithmetic mean to match with the vertical resolution of the grid, and then it was extrapolated laterally to the fault surfaces. Overall all intra-reservoir faults provide good connectivity between C and D sands, suggesting the likelihood of cross-fault gas flow from the lower D sand to the upper C sands.

As an exemplification of the relationship between SGR and potential fluid flow communication between C and D sands, Allan diagrams and SGR maps for two-intra reservoir faults are presented below. In both cases, the C-to-D juxtaposed areas are well above the identified gas-water contact, and regarding a common contact through-out the reservoir, low SGR values (<0.2) suggest a good connectivity between juxtaposed sands.

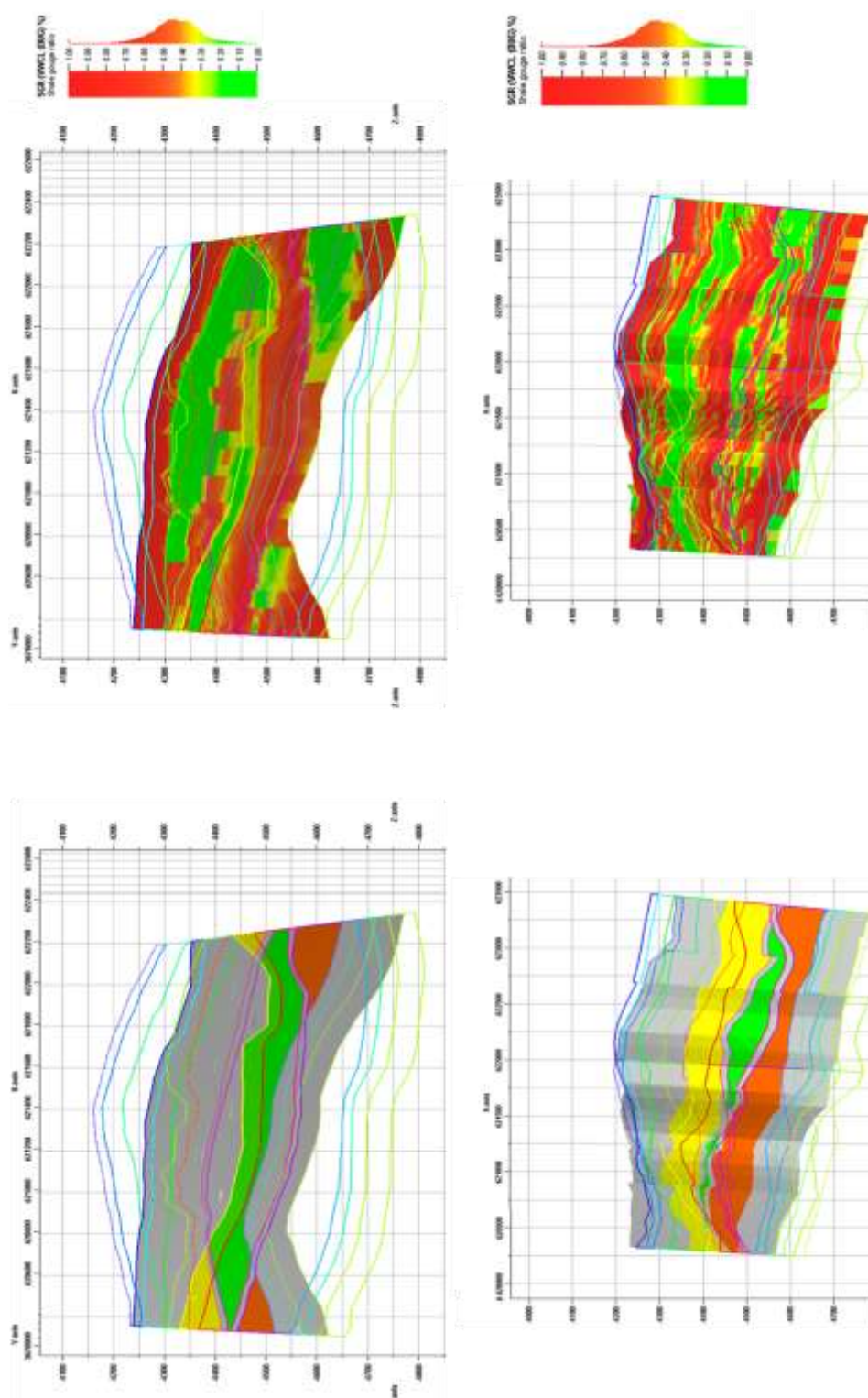


Figure 6-3 Allan Diagrams for selected Karish Main faults

Figure Note: 011 K Norm sEW dN 001* (top) and 010 K Norm sNW dSW 009 (bottom) showing sand-sand juxtapositions (yellow: C-to-C sands, green: C-to-D sands, orange: D-to-D sands). Shale Gouge Ratio (SGR) maps for the mentioned faults.

Based on the findings of the above fault seal analysis, Energean Oil & Gas has built dynamic models that contain both C and D sands, as opposed to NSAI's approach (CPR June 2013), in order to simulate the gas migration that occurs from D to C sands, due to depletion. Furthermore all internal faults in Karish Main area, were considered unsealing. The two boundary faults are calculated as sealing (Main and East Fault) shown in Figure 6-4.

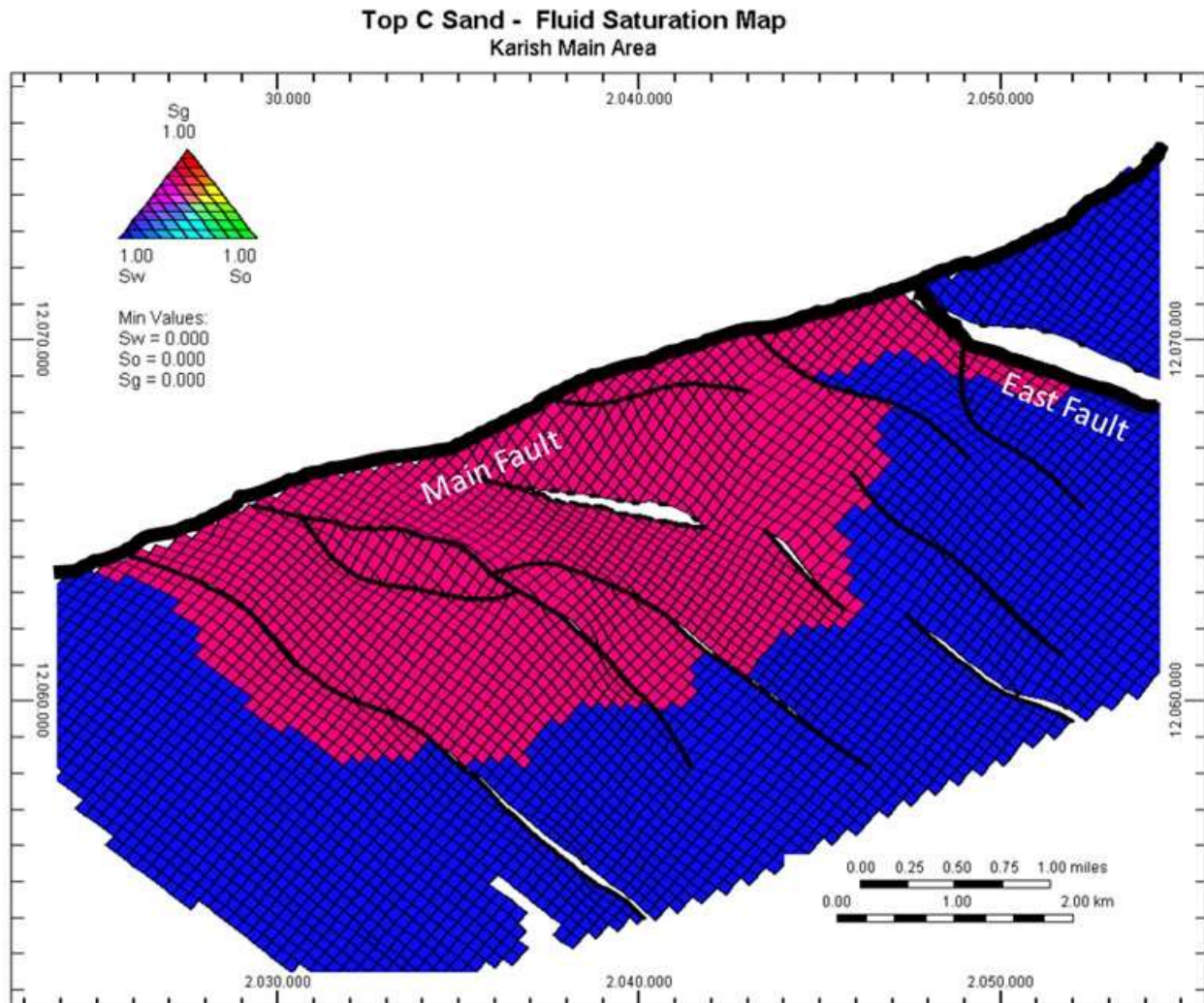


Figure 6-4 Fluid Saturation Map at initialization – Location of Sealing Faults

6.1.1.2 Porosity

Model porosity data is imported directly from the static models and reflects a variable aerially and vertically distribution ranging between 20% and 26% for the Karish gas bearing rocks as is shown in Figure 6-5 and 15% to 27% for the Tanin gas bearing rock as is presented in Figure 6-6. The cells corresponding to the areal discontinuous shales are declared with 0.15% porosity in both models.

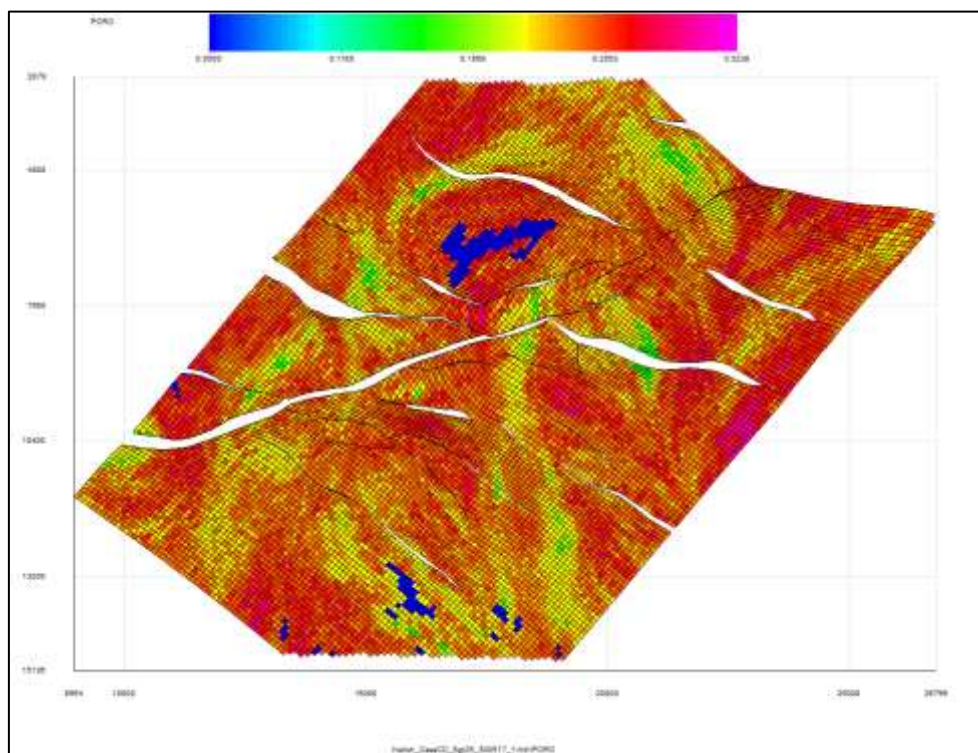


Figure 6-5 Karish porosity 2D map on layer C (top)

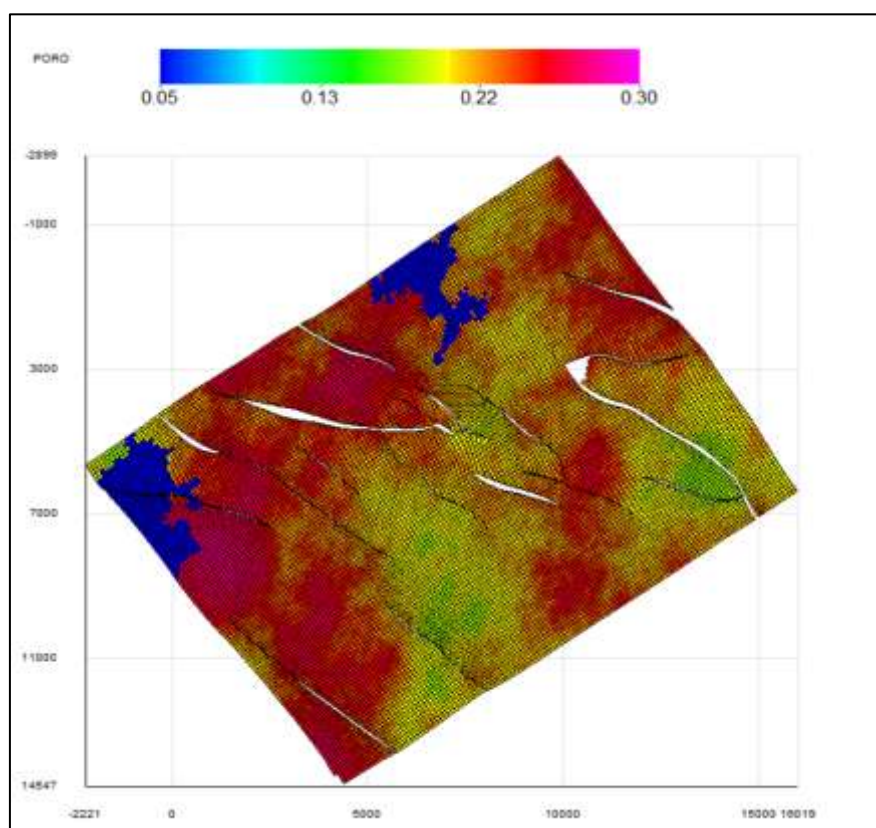


Figure 6-6 Tanin porosity 2D map on layer A (top)

6.1.1.3 Permeability

Model permeability is imported directly from the Karish geological model and is assumed to be isotropic with the X and Y values the same. The permeability in Z direction have been reduced to 50% of the permeability X and Y ($K_v/k_h=0.5$) in the best-technical case, the same approach was used for Tanin model. The Karish average permeability is ~250 mD and ~300 mD for Tanin as shown in Figure 6-7 and Figure 6-8. Inter-horizon and inter sand shales are model with less than 0.1mD properties to reflect their barrier type properties.

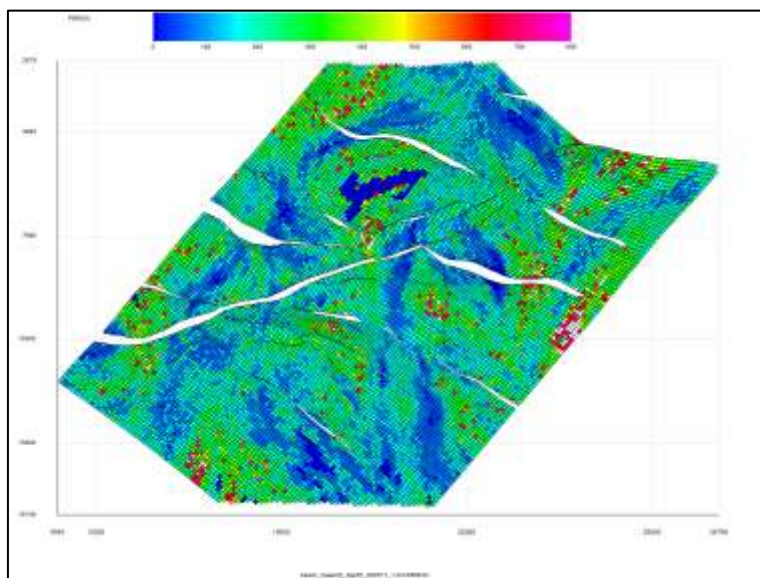


Figure 6-7 Karish permeability 2D map on layer C (top)

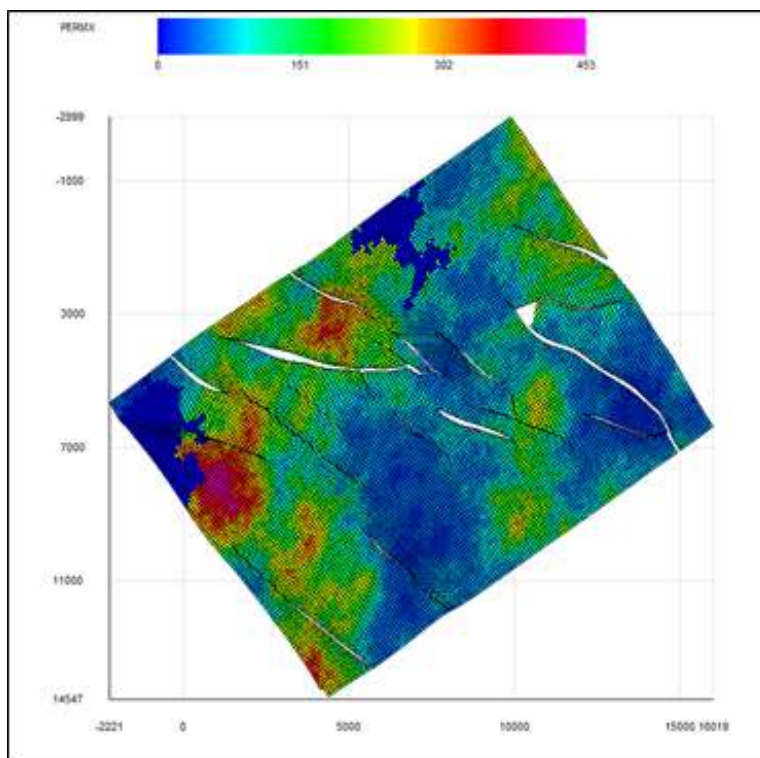


Figure 6-8 Tanin permeability 2D map on layer A (top)

Shales ($V_{shale} > 0.5$) in the binary facies model described in section 4, were modelled as being barriers with zero permeability, regardless of shale extent or V_{shale} .

There is significant uncertainty in intra-reservoir shale transmissibility, given the hydrocarbon phase of the reservoir and given that the intra-reservoir shale have a significant silty component, shown by the Vshale curve and percussion SWC (Figure 6-9). Furthermore, these intra-reservoir shales are almost certainly offset by sub-seismic faulting given the significant convergence (uplift) the Karish fault block has experienced since the Tamar sands have been deposited. This is evidenced by the 50 psi overpressure seen in within the isolated overburden in Karish-1 (4318-4323m Figure 4-15) which demonstrates c.138m uplift of the Karish structure since charge of the Tamar sands.

In the main Karish reservoir (C Sand), the most shale prone part of the reservoir, calculated PHIT is always >0.08, with 0.08 being approximately 0.1mD. The average shale porosity (PHIT) in the shale prone sections of the Lower C Sand is 0.12, which equates to 0.8mD. The permeability of the intra-reservoir shales has therefore been modified so as to independently model each voxel as a random value between 0.1 and 0.8mD (Figure 6-10).

Whilst the shales have been modified to have some horizontal permeability, the PHIT range seen in the Karish-1 shale prone sections is 0.08-0.12, this equates to a PHIE of 0.005 and 0.04 respectively. Using the adopted Cuddy transform for calculating Sw (Section 4.5.3), assuming an optimistic BVW and a PHIE at the high end of the range (0.04), plus an infinite elevation above the FWL, results in Sw=1. These intra-reservoir shales are therefore modelled as 100% water bearing, regardless of elevation above the FWL.

All shale intervals interpreted as Maximum Flooding Surfaces (CD Shale & D Shale) are still modelled with zero permeability given >> Vshale with a lack of silts/sands. These shales rely on offset across faults (juxtaposition) to access the gas volume in the D Sand.

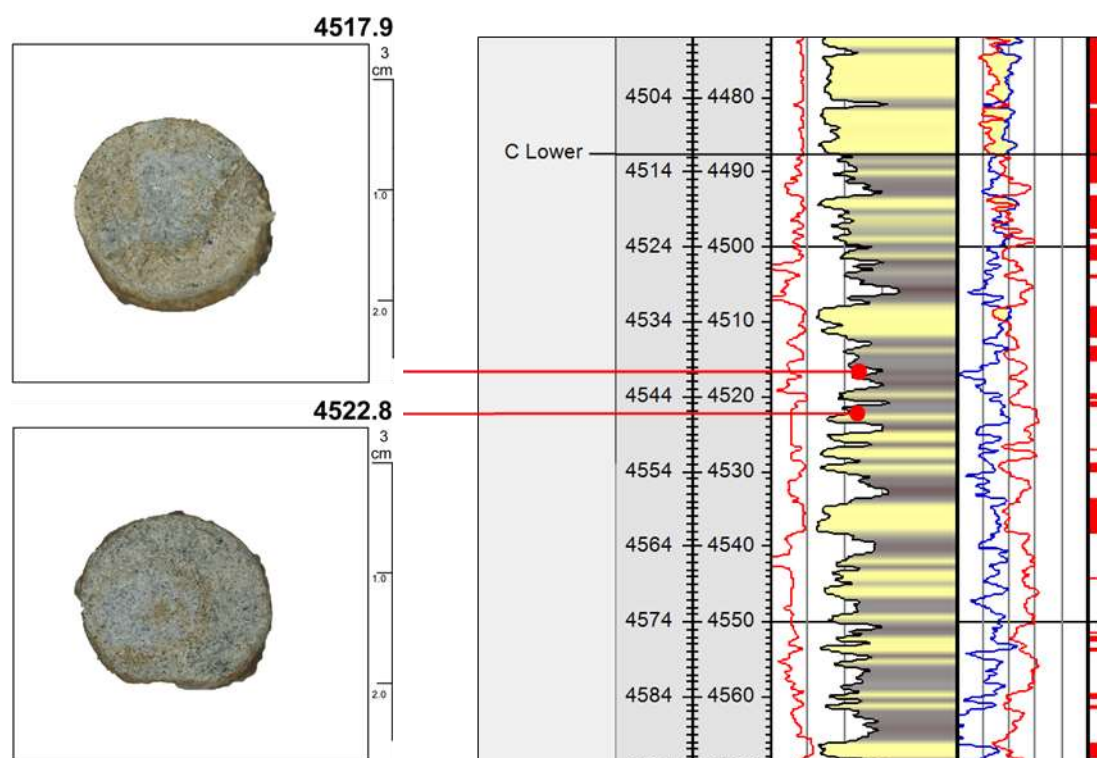


Figure 6-9 Core plugs show intra-reservoir shales.

Figure Note: Described in the geological model as having no permeability (shown as white flag on right-hand track), have a significant silty, even sandy component

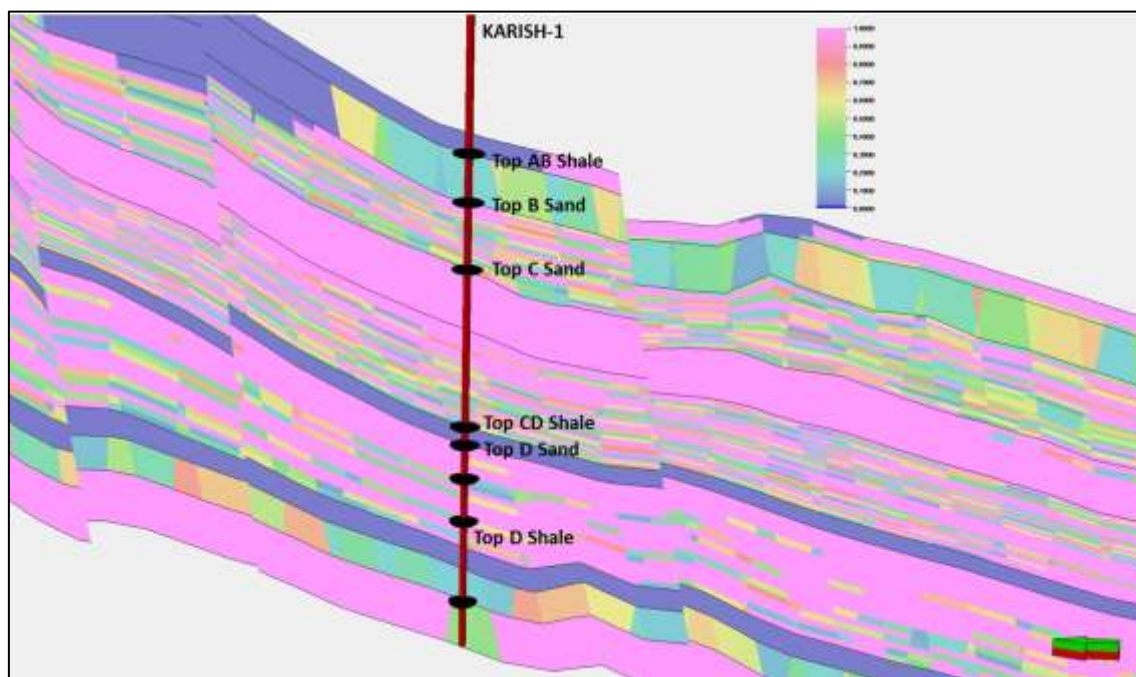


Figure 6-10 Intra-reservoir shale permeability.

Figure Note: Permeability's have been modelled with random values between 0.1-0.8mD, whilst Maximum Flooding Surfaces retain zero permeability

6.1.1.4 Relative Permeability and Capillary Pressure

The reservoir rock-fluid properties for layers A, B, C and D were estimated based on Corey Correlation due to the absence of special core analysis laboratory.

Corey Functions were used to generate a set of curves for the best-technical case of each field, with values based on analogue gas fields. For Karish the Corey exponents of 5 (water) and 2 (gas) were used. The residual gas saturation (Sgr) of 25%, initial water saturation (Swi) of 20% and the relative permeability end points were also based on analogue fields. Relative permeability endpoints for krw and krg of 0.8 and 0.9, respectively were used in the construction of the curves. While relative permeability in Tanin field were calculated using Corey exponents of 5 (water) and 2.25 (gas). Residual gas saturation (Sgr) of 25%, initial water saturation (Swi) of 23.9%. Relative permeability endpoints for krw and krg of 0.2 and 1. The resulting curves for each field are show in Figure 6-11.

Model saturation can be assigned through either enumeration or the assignment of Capillary Pressure (Pc). In this exercise, the latter has been adopted with a Pc correlation based on the height above the free water level (HAFWL) observed in the well log for the layers A&B and C&D, which was derived by Down Under Geophysical (DUG). This work identified two distinct correlations, one for the poorer A and B sands and one for the better C and D sands. Both used an exponential correlation and are shown below:

$$Sw = ((0.12774 * \exp(-0.08118 * HAFWLm) + 0.045)) / PHIE \quad - \text{ (A\&B layers)}$$

$$Sw = ((0.12774 * \exp(-0.120 * HAFWLm) + 0.028)) / PHIE \quad - \text{ (C\&D Layers)}$$

Once the saturation height function is derived, a capillary pressure vs water saturation relationship can be calculated for porosity values using the equation for capillary pressure from height above FWL. Figure 6-12 displays the Water-Oil Capillary Pressure estimation for C&D layers of Karish field.

$$Pc = HAFWL * (\text{water gradient} - \text{gas gradient})$$

Since the Cp and Corey rel-perm are porosity dependant, it would normally be necessary in an oil system to assign these properties by porosity band. This can have a substantial impact on run times and since this is a relatively simply two phase gas problem, these simulation model inputs have been simplified with just three

saturation tables (rel-perms/capillary pressure) assigned for the A&B, C&D and shale intervals. Capillary pressures were neglected on Tanin simulation model in order to simplify and speed up calculations.

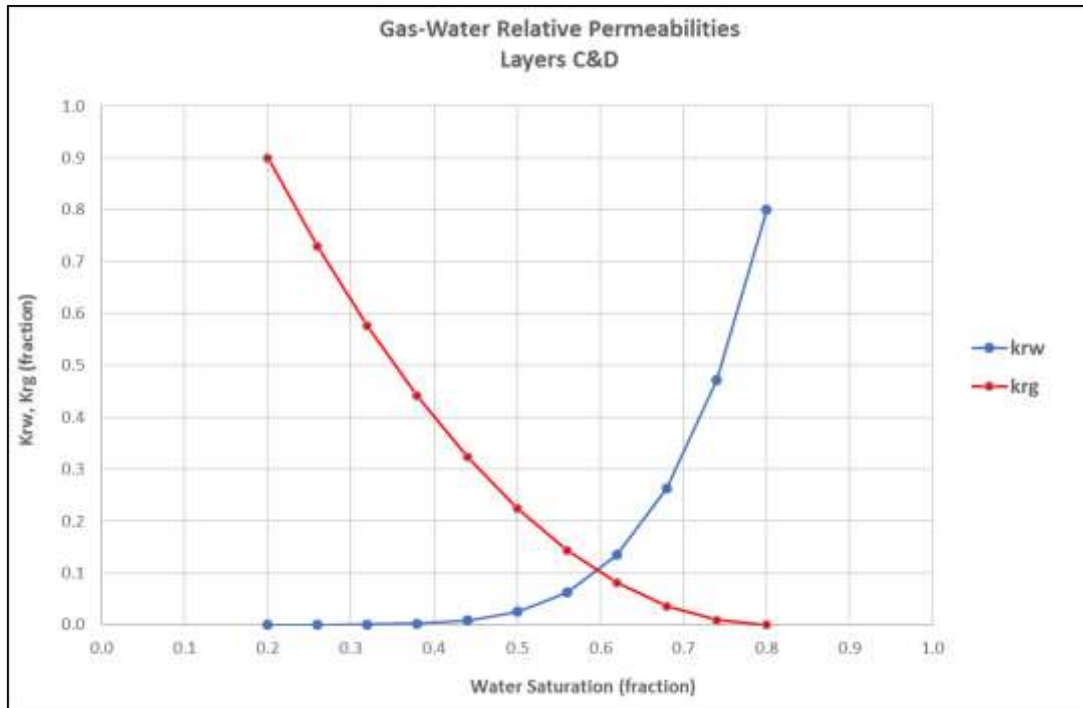


Figure 6-11 Gas-Water relative permeability curve for layers C&D

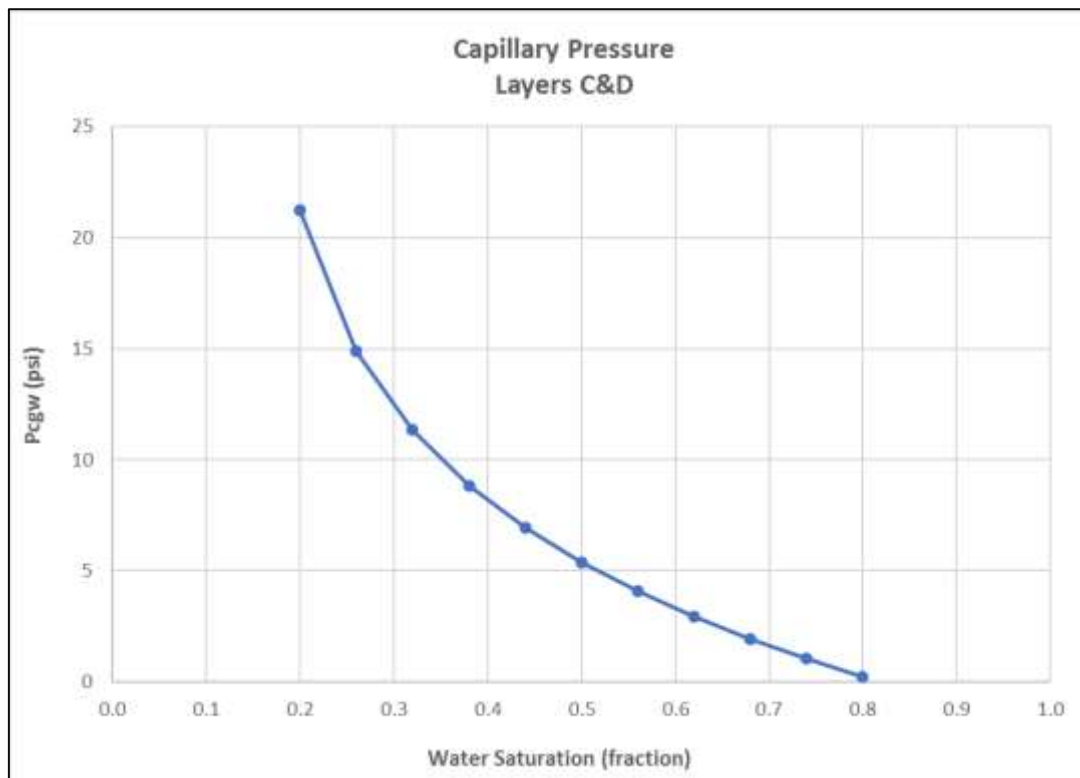


Figure 6-12 Capillary pressure curve for layers C&D

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6.1.2 Aquifer Description

In the best technical case models aquifer properties were assigned to mimic the Tamar field performance (~200 psia pressure decrease per 6.25% Recovery Factor) in the simulation model. The aquifer used was a Fetkovich model and was placed and connected on the XZ and YZ grid boundaries.

The radial extent at ~50 km is in alignment with the regional well data that show that the Miocene sands of the Levantine Basin are aerially extensive across most, if not all of its offshore footprint and may well be in pressure communication through faults and unconformities in the system. In this case, all of the current discoveries (Leviathan, Tamar, Tanin, Karish) and yet to find volumes in these Miocene sands will share this one common aquifer, which will act as a conduit for pressure equilibration and support to any of the fields or yet to find accumulations that will be placed on production.

The level of support that is provided by the aquifer will be governed by (i) the permeability of the system which controls the responsiveness of this pressure support, i.e. speed of recharge, and (ii) the rock, water and any associated trapped hydrocarbon compressibility.

The Fetkovich aquifer model uses a simplified approach based on a pseudo-steady-state productivity index and material balance relationship between the aquifer pressure and the cumulative influx. The water influx rate is directly proportional to the pressure drop between the average aquifer pressure and the pressure at the reservoir/aquifer boundary. The method neglects the effects of any transient period. By varying the aquifer volume and the productivity index, the Fetkovich model can encompass a range of aquifer behaviour from steady state to the 'pot' aquifer.

Based on the dimension structure of the aquifer a volume of 6.2898E+11 stb was included as parameter of input for the aquifer definition. The aquifer parameters were modified to honour the expected pressure drop as described above and the result is shown in the Figure 6-43.

6.1.2.1 Alternative aquifer scenarios.

Alternative aquifer scenarios were investigated, in order to ascertain the impact of the calculated pressure support scheme on field recovery factors. Early material balance models with a weak, or no, aquifer demonstrated the beneficial effect of a constrained strength aquifer to the total gas field recovery. This is attributed to the smaller gas trap saturation achieved when a weak or no aquifer is assumed. Higher Recovery Factors can be achieved if reservoir pressures can be reduced. The Karish FPSO has been designed to allow low pressures to be achieved if the aquifer is weaker than currently assumed. The inlet choke can be opened progressively reducing the HP separator pressure to 130 bar (from an initial pressure of 430 bar). Further reductions could be achieved if inlet compression were provided. Although in these schemes condensate drops out in the wells and sub-sea system the high velocities prevent it from dropping or collecting. The inley HP separator on the FPSO has been designed for a full inventory of a single flowline/riser.

6.1.3 Reservoir Pressure and Temperature

6.1.3.1 Reservoir Pressure

Estimate of reservoir pressure is based on measurements taken by the RCI (reservoir characterisation instrument) formation tester run during final wire line logging in the Karish-1 well on 18th May 2008 and Tanin-1 well on 07th February 2012. A plot of the pressures recorded is shown in Figure 6-13, which gives a pressure at the gas water contact of 4512 m TVDSS of 7886 psia for the Karish main area and Figure 6-12 indicates a pressure at the gas water contact of 5095 m TVDSS of 8732 psia for the Tanin-1 well. Good quality formation pressure measurements were obtained for the A, B, C and D layers.

The deeper gas water contact in Karish North and Karish East estimated at 4774 m TVDSS, resulted in a higher projected reservoir pressure in these prospective accumulations of 7997 psia, based on the extrapolation of a gas gradient taken in the Karish-1 well.

- High Confidence FWL at 4512m TVDSS for C Sand, which is used for GWC in Karish Field model,

- Formation pressures show minimal vertical pressure differential – good vertical connectivity expected within main reservoir units,
- High confidence in the aquifer pressure, pressure gradient and performance
- Aquifer pressures within the available dataset shows that the Early Miocene of the Levant Basin are very well connected over large geographic distances. Strong aquifer support should be expected.

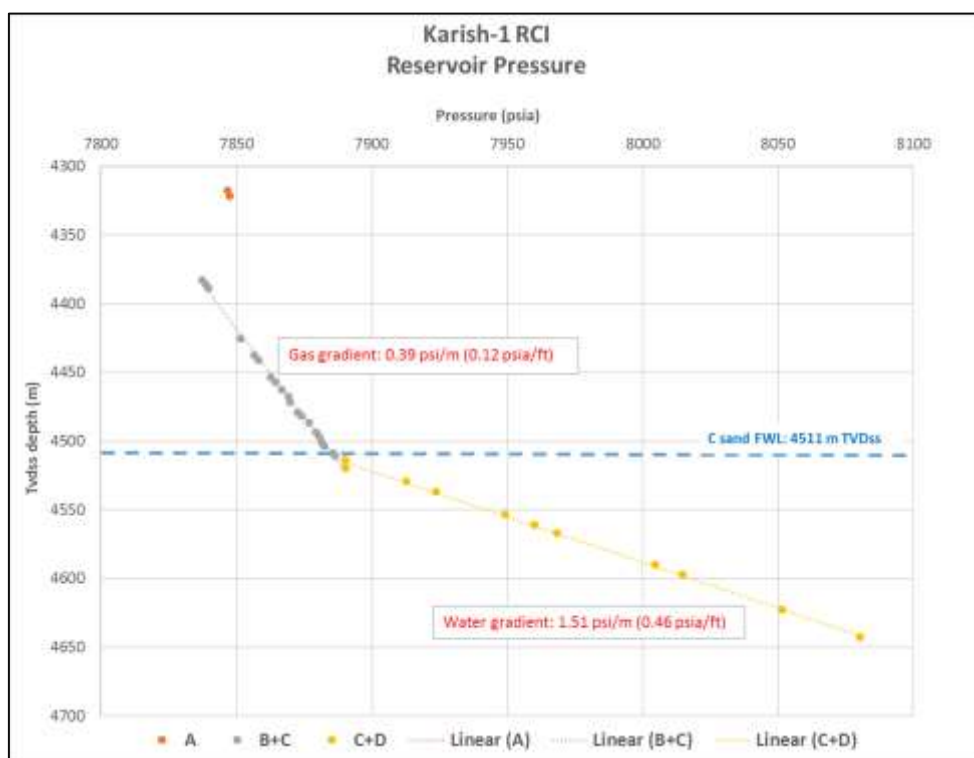


Figure 6-13 Karish-1 formation pressure tester (RCI) results

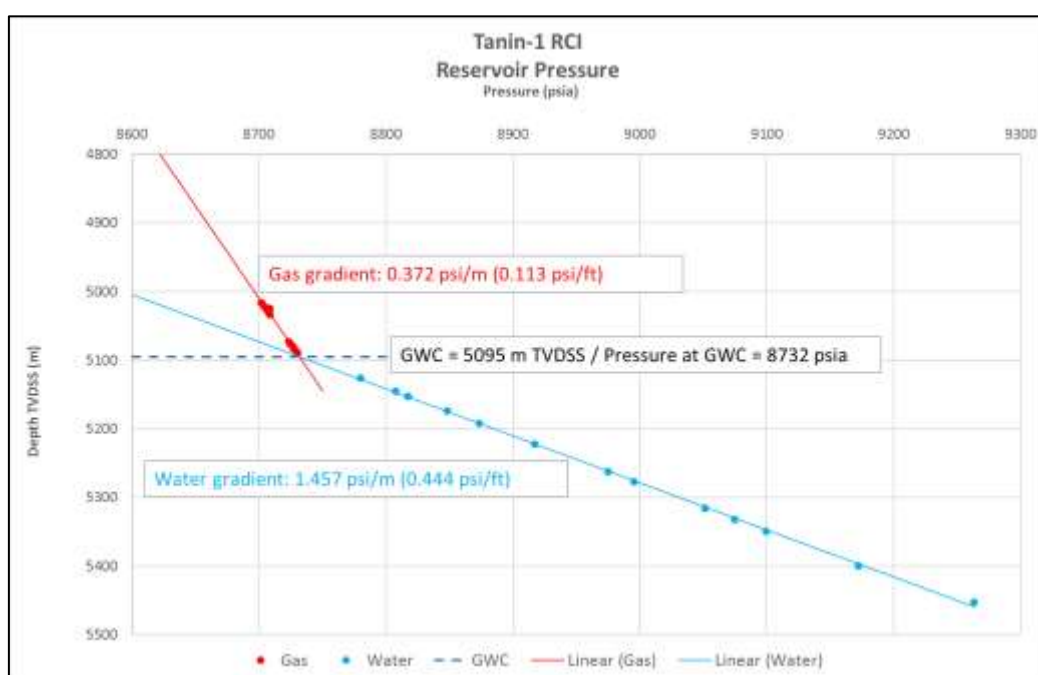


Figure 6-14 Tanin-1 formation pressure tester (RCI) results

6.1.3.2 Reservoir Temperature

The RCI run in wells Karish-1 and Tanin-1 measured temperatures as well as pressures. The reservoir temperature in Karish field is measured at 159 degF at the gas water contact of 4512 m TVDSS. Reservoir temperature in Tanin field was measured at 172 degF at the gas water contact of 5095 m TVDSS. Two plots showing sample temperature v's Depth are presented in Figure 6-15 and Figure 6-16.

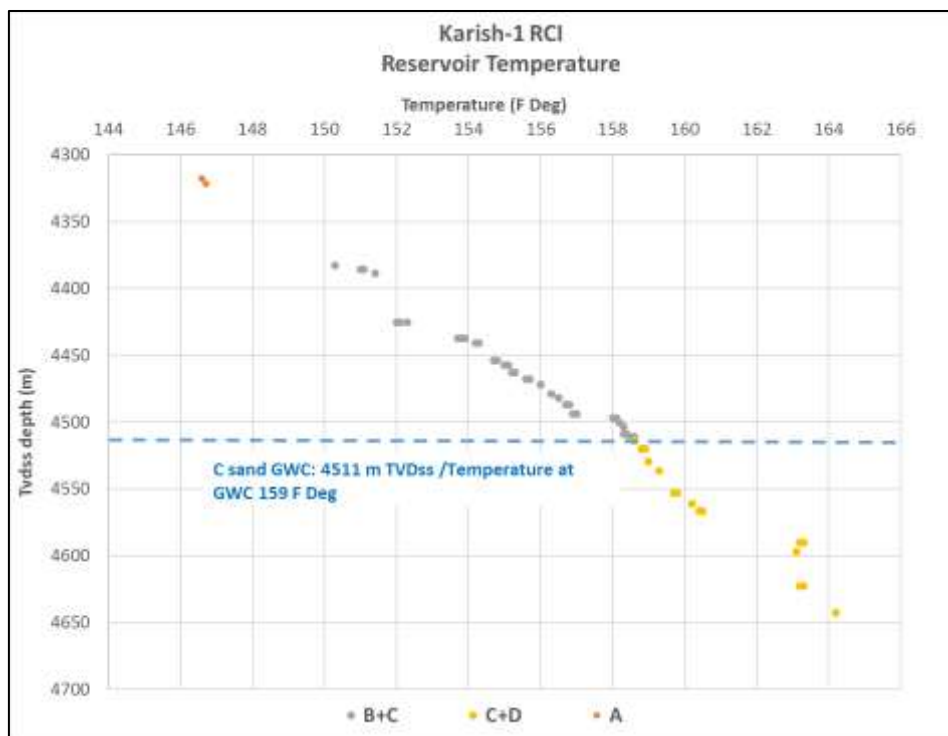


Figure 6-15 Karish RCI Temperature Measurements

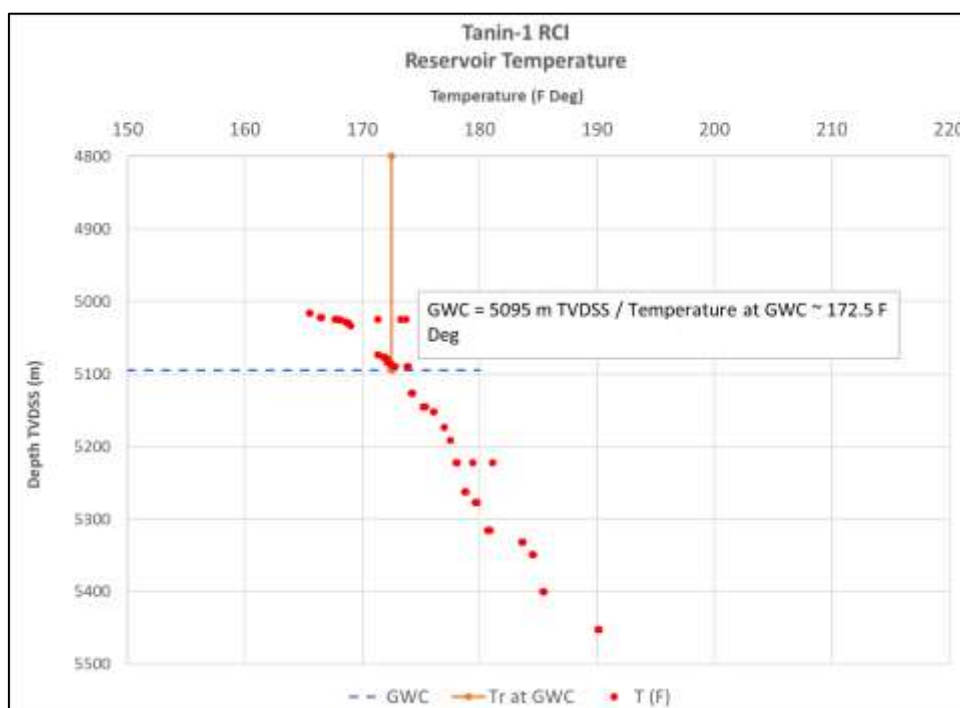


Figure 6-16 Tanin RCI Temperature measurements

6.1.4 PVT Modelling

6.1.4.1 Karish PVT Data

The PVT analysis performed on Karish and Tanin fluids is based on 12 gas and water samples taken in the Karish-1 well Details of these samples are listed Table 6-2.

Table 6-2: Sample List from Karish 1 Well – Open Hole Sampling

SAMPLE NUMBER	SAMPLE TYPE	SAMPLING DATE	SAMPLING CONDITIONS		SAMPLE VESSEL				
			Pressure psig	Temperature °F	Cylinder Number	Cylinder Type	Single Phase	Pressure Rating	Sand
1.01	Subsurface Gas	18-May-13	7867.5	159.9	10056391	600cc Baker RCI	yes	20,000 psig	C
1.02	Subsurface Gas	18-May-13	7867.5	159.9	10056422	600cc Baker RCI	yes	20,000 psig	C
1.03	Subsurface Gas	18-May-13	7867.5	159.9	10056455	600cc Baker RCI	yes	20,000 psig	C
1.04	Subsurface Gas	18-May-13	7867.5	159.9	10133562	600cc Baker RCI	yes	20,000 psig	C
2.01	Subsurface Gas	18-May-13	7839.6	154.8	10169763	600cc Baker RCI	yes	20,000 psig	B
2.02	Subsurface Gas	18-May-13	7839.6	154.8	10169764	600cc Baker RCI	yes	20,000 psig	B
2.03	Subsurface Gas	18-May-13	7839.6	154.8	10170203	600cc Baker RCI	yes	20,000 psig	B
3.01	Subsurface Gas	18-May-13	7850.2	150.7	10170204	600cc Baker RCI	yes	20,000 psig	A
3.02	Subsurface Gas	18-May-13	7850.2	150.7	10170209	600cc Baker RCI	yes	20,000 psig	A
4.01	Formation Water	19-May-13	7912.8	159.6	10177285	600cc Baker RCI	yes	20,000 psig	
4.02	Formation Water	19-May-13	7912.8	159.6	10354564	600cc Baker RCI	yes	20,000 psig	
4.03	Formation Water	19-May-13	7912.8	159.6	11682769	600cc Baker RCI	yes	20,000 psig	

Three international laboratories, i.e. Intertek, Weatherford and SGS have performed gas analysis on the Karish samples. The SGS report is considered the most accurate since:

- The report contains information about all samples and is more complete,
- Single stage flash, gas and ion chromatography measurements applied directly to the RCI sample bottles were used in order to determine gas, condensate and water compositions of the samples,
- The Intertek samples received in Houston were received after international shipment and transfer of fluid from RCI bottles to international approved carrying containers were depressurized to ~5000psi for shipment, causing liquids to drop from the gas which is believed to have remained when the samples were transferred back out of the shipping bottles, i.e. significantly lower CGR from that seen in all the other samples analysed,
- The Weatherford results used samples received from Intertek ~9 months after shipping and performed their analysis with gas chromatography performed only on the off gas and stabilised liquids, which showed the sampling process or samples to have been contaminated with 5% Nitrogen seen in the analytical results.

Based on the above observations and a detailed and extensive review of the laboratory work by Energean Oil and Gas, Genesis and Granherne (Ref: PVT Report) in which a full PVT simulation was carried out in Hysis on the results from SGS, Weatherford and Intertek, it was established that sample 1.03 was the most complete and accurate and would be used for the future simulation studies. The results of this evaluation identified a small increment in the CGR measured by SGS (from 11.3 to 14.7 bbls/mmscf) and also established that further

liquids will be released from the gas stream by treating them to sales specification. This condensate yield is approximately 9.5 bbl/mmscf for Karish gas. This is cumulative to the “oil” CGR. As fully detailed in the provided reference material this “oil” CGR was underestimated by the SGS work due to carry over of liquid into the flash separator gas stream. Compensating for this carry over increased the SGS measured value of 11.3 to 14 bbl/mmscf/day. Subsequent equation of state work modelling undertaken by Granherne increased this value to 14.7 whilst additional work by Genesis decreased it to 13.4. The differences relate to how specific aromatic and heavier hydrocarbons are modelled. Energean has used the lower (and latest) of these figures to forecast liquid yields, i.e. it has adopted the Genesis PVT model that predicts an “oil” or flash CGR of 13.5 and a “condensate” or treatment CGR of 9. Hence the Karish C sand CGR is 22.4 bbl/mmscf/day. Gas in the Karish D sand is assumed to be similar.

A comparison of measure and simulated Karish single stage flash properties is presented in Table 6-3. Data from the laboratory, the Granherne HYSYS simulation, the HYSYS simulations and the latest Genesis characterisation are presented.

All the simulation studies outlined in this document have assumed a CGR (condensate to gas ratio) of 13.4 stb/mmscf for the well stream gas, based on Genesis recombined composition approach. The resulting phase envelop is presented at different flash conditions is in Figure 6-17 and Figure 6-18.

Table 6-3: PVT model data compared

Parameter	SGS Laboratory	Granherne	Genesis	
	Karish SGS Sample 1.03 (measured properties)	Paraffinic Characterisation (SGS Sample 1.03 Recombined composition)	Conventional Characterisation Approach (matching measured CGR and Density)	SGS Sample 1.03 recombined Composition
"CGR Oil"	11.3 (1)	14.7	11.1	13.4
Density	801	7.59	814	814
API Gravity	45	55	42	42
Oil MW	167	173	167	167
Gas SG	0.619	0.611	0.612	0.612

Table Note: (1): this is increased to 14 when the liquid in the gas stream is added to the CGR

Furthermore Table 6-4 presents the fluid composition of Genesis’s model after recombining composition.

Table 6-4: Karish Fluid composition

KARISH FLUID COMPOSITION (mol %)		
	SGS Lab Tests	Genesis Recombined Composition
N2	0.627	0.627
CO2	0.076	0.076
H2S	0.00	0.00
C1	94.245	94.245
C2	1.558	1.558
C3	0.944	0.944
IC4	0.275	0.275
NC4	0.0297	0.297
IC5	0.180	0.180
NC5	0.114	0.114
Cyclohexane	-	0.147
Toluene	-	0.006
E-Benzene	-	0.019
m-Xylene	-	0.008
p-Xylene	-	0.008
o-Xylene	-	0.006
C6	0.190	0.190
C7	0.370	0.277
C8	0.331	0.178
C9	0.157	0.116
C10	0.100	0.1
C11	0.096	0.096
C12	0.089	0.089
C13	0.111	0.111
C14	0.062	0.062
C15+	0.178	-
C15-19	-	0.115
C20-24	-	0.037
C25-29	-	0.016
C30+	-	0.010

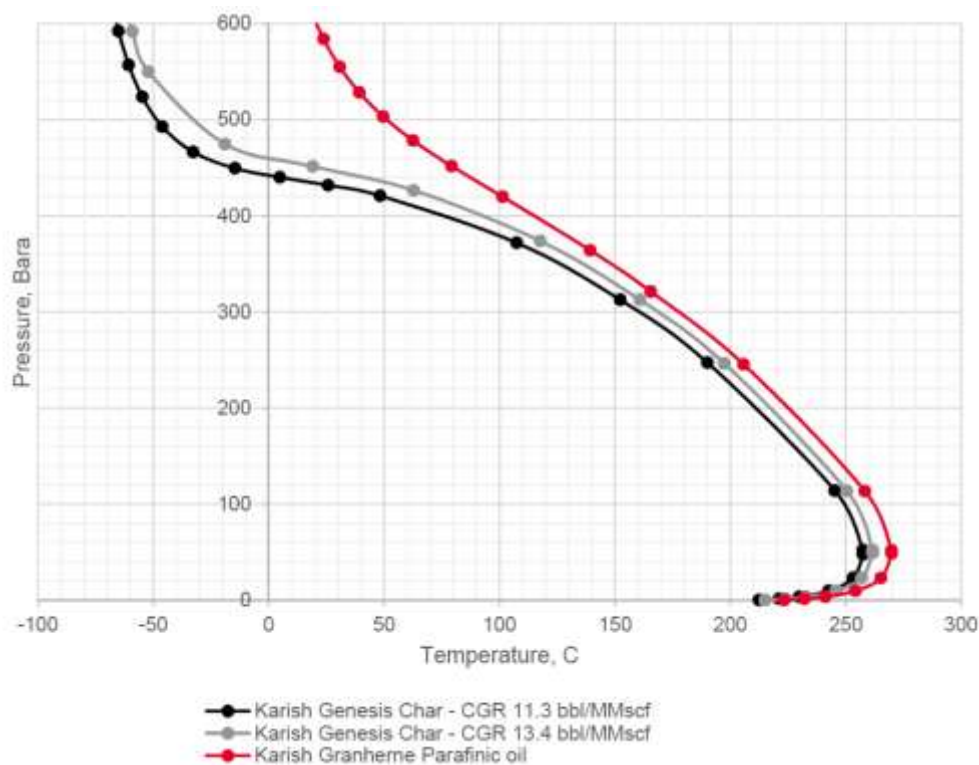


Figure 6-17 Karish Field – Reservoir Fluid Phase Envelope Comparison

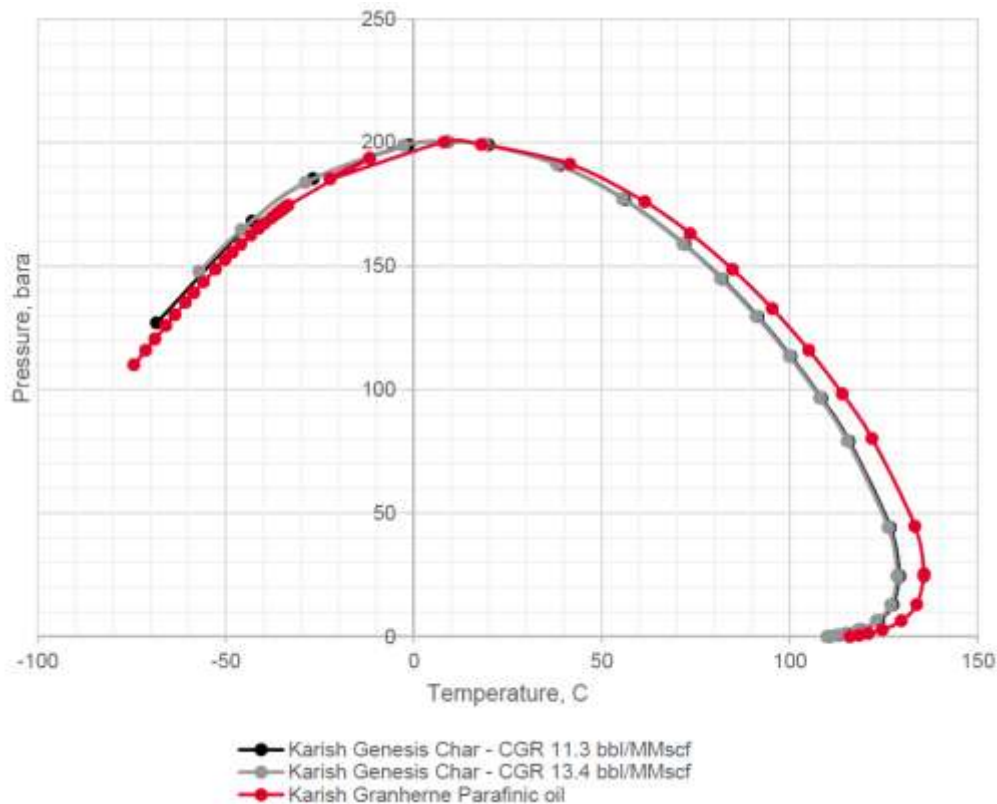


Figure 6-18 Karish Field - Production Separator Gas Phase Envelop Comparison

6.1.4.2 Tanin PVT Data

The PVT analysis performed on Tanin fluids is based on 10 gas and water samples taken in the Tanin-1 well. Details of these samples are listed below.

Table 6-5: Sample list from Tanin-1 well

SAMPLE NUMBER	SAMPLE TYPE	SAMPLING DATE	SAMPLING CONDITIONS		SAMPLE VESSEL				
			Pressure psia	Temperature °F	Cylinder Number	Cylinder Type	Single Phase	Pressure Rating	Sand
1(5048.5m)	Subsurface Gas	12-Feb-12	8693	173.6	10170247	600cc Baker RCI	yes	20,000 psig	A
2(5048.5m)	Subsurface Gas	12-Feb-12	8693	173.6	10170252	600cc Baker RCI	yes	20,000 psig	A
3(5048.5m)	Subsurface Gas	12-Feb-12	8693	173.6	10170224/821394	600cc Baker RCI	yes	20,000 psig	A
4(5048.5m)	Subsurface Gas	12-Feb-12	8693	173.6	10226828/821394	600cc Baker RCI	yes	20,000 psig	B
5(5114.0m)	Subsurface Gas	12-Feb-12	8717	173.1	10354540/821390	600cc Baker RCI	yes	20,000 psig	B
6(5114.0m)	Subsurface Gas	12-Feb-12	8717	173.1	10354564/821386	600cc Baker RCI	yes	20,000 psig	B
7(5114.0m)	Subsurface Gas	12-Feb-12	8717	173.1	11682770/821396	600cc Baker RCI	yes	20,000 psig	B
7(5246.8m)	Formation Water	12-Feb-12	8903	180.2	11682772/820957	600cc Baker RCI	yes	20,000 psig	
8(5246.8m)	Formation Water	12-Feb-12	8903	180.2	10354565/821378	600cc Baker RCI	yes	20,000 psig	
9(5246.8m)	Formation Water	12-Feb-12	8903	180.2	11682777/821383	600cc Baker RCI	yes	20,000 psig	

Five samples were evaluated from the Tanin-1 well in Israel using a mobile laboratory sourced from SGS. From these samples a CGR was measured for the well stream ranging from 2.01 to 3.89 bbls/mmscf. Following a review of the analytical process and the available sample data it was confirmed that sample 4 was seen to be the most complete and representative. A further liquid recovery of ~2.5 bbl/mmscf will be achieved through the cooling of the processed gas giving a liquid yield of around 4.7 bbls/mmscf. (Ref: PVT Report) The quality of the match achieved between SGS Lab tests and Energean's PVT model is presented in Table 6-6. In addition Table 6-6 presents the fluid composition of Energean's model after regression, while matching the lab results.

All the simulation studies outlined in this document have assumed a CGR (condensate to gas ratio) of 2.22 stb/mmscf for the well stream gas. The resulting phase envelop is presented in Figure 6-19.

Table 6-6: PVT Tanin Model Match Quality

TANIN PVT MODEL MATCH QUALITY				
	Formation GOR (scf/bbls) / (bbls/scf)	Gas Gravity (air=1.0)	Oil Gravity (API)	Condensate Molecular Weight (g/mol)
Energean PVT Model	449801 / 2.22	0.571	45.90	197.54
SGS Lab Tests (Flash to SC)	450540 / 2.22	0.571	45.8	169.8
Error (%)	0.16%	0.0%	0.21%	16.36%

Table 6-7: Tanin Fluid Composition

TANIN FLUID COMPOSITION (mol %)		
	SGS Lab Tests	Energean PVT Model
N2	0.629	0.629
CO2	0.170	0.170
H2S	0.000	0.000
C1	98.117	98.14
C2	0.416	0.416
C3	0.176	0.176
IC4	0.048	0.048
NC4	0.033	0.033
IC5	0.037	0.037
NC5	0.014	0.014
C6	0.025	0.025
C7	0.079	0.079
C8	0.077	0.078
C9	0.040	0.036
C10	0.033	0.029
C11	0031	0031
C12	0018	0027
C13	0.016	0.014
C14	0.01	0.009
PS-1	0.031	0.027

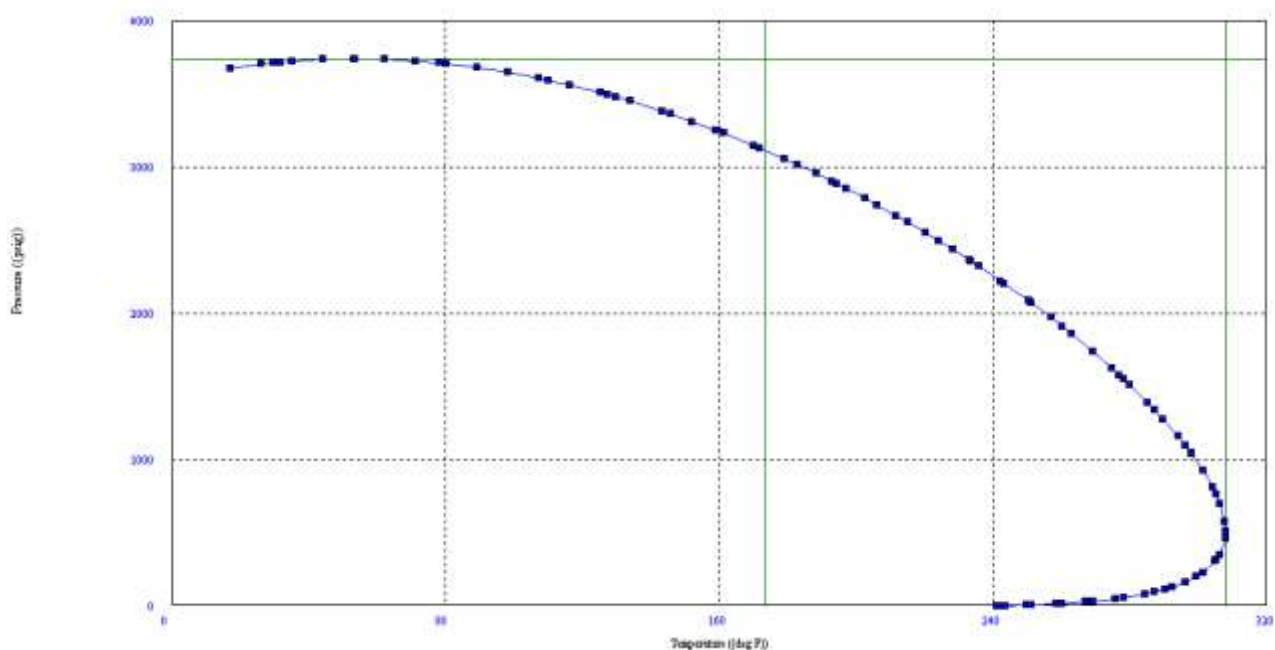


Figure 6-19 Tanin Phase Envelop as per Energean PVT Simulation Model

6.1.4.3 Gas PVT Data for Dynamic Model

Two phases, gas and water are represented in the Karish field Eclipse simulation model. Properties input into the simulation model are based on the analysis carried out by Energean and are summarised below in Table 6-8

Table 6-8: Karish-1 PVT Karish-1 well sample (1.03) properties

	KARISH-1 PVT KARISH-1 WELL SAMPLE (1.03) PROPERTIES	TANIN-1 PVT KARISH-1 WELL SAMPLE (1.03) PROPERTIES
GOR (scf/stb)	88471	450540
CGR (stb/mmscf)	13.4	2.2
Gas gravity	0.612	0.571
Oil gravity (°API)	42	46
CO2 (%)	0.076	0.171
N2 (%)	0.627	0.629

The Eclipse fluid (gas dry) property variation with pressure was derived in MBAL using the above PVT data and is shown below in Table 6-9. This represents the dry gas property data input for the simulation model. A black oil PVT (dry gas) approach for the Karish field has been employed, as opposed to an Equation of State model as it is predicted that we stay above the dew point of the fluids over the life of the field and therefore can benefit from the increased computational speed offered by this solution.

Consequently, a constant CGR (condensate gas ratio) of 13.4 stb/mmscf is defined in the simulation model defining the liquid recovery associated with the well gas streams. The Tanin CGR is lower at 2.2 bbl/mmscf. The simulation model does not attempt to capture the incremental additional liquid volumes that would result from cooling in the gas plant.

Table 6-9: Eclipse gas property variation

PRESSURE	GAS	GAS
	FVF	Viscosity
(psia)	(RB/mscf)	(centipoise)
PVDG		
670.895	4.33803	0.013365
1327.09	2.07397	0.014644
1983.28	1.34451	0.016425
2639.48	1.00898	0.018563
3295.67	0.82783	0.020855
3951.87	0.718723	0.023148
4608.06	0.647226	0.025357
5264.26	0.597195	0.027449
5920.45	0.560328	0.029413
6576.65	0.532018	0.031256
7232.84	0.509543	0.032989
7889.04	0.491208	0.034621

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6.1.4.4 Water Properties for the dynamic model

A sample of water (4.03) was taken in the well Karish-1 on 19th May 2008. The sample was analysed and using standard correlations the water salinity was estimated as 28124 NaCl ppm.

The hydrocarbon and the formation water physical properties were derived from samples data and from modelling the fluid within the PETEX packages MBAL for input to Eclipse. Using standard correlations, the viscosity at reservoir conditions was estimated at 0.465 cp, the formation volume factor at 0.9979 rb/stb and the water compressibility at 3.0×10^{-6} psi⁻¹.

6.1.5 Inflow Reservoir Performance

Energean's Reference case assumes an export target of 3 BCM/year requiring three wells in Karish field, with a daily contracted production rate of ~100 mmscf/day, but with the capacity to deliver up to 200 mmscf/day to cover the case of an assumed loss of one well. The nodal analysis undertaken and performed using PROSPER (PETEX) software was aimed at identifying the length of reservoir section to be completed as part of the Open Hole Gravel Pack (OHGP) and for recommending the optimum size of the production tubing to be employed in the producing wells. It was also used to generate the appropriate VLP curves for the completion configurations under evaluation.

The choice of the tubing size was guided by the optimum utilisation of the natural reservoir energy over the life of the field. Employing an oversized tubing may lead to a disproportionate liquid phase loss due to slippage, or an excessive liquid loading during lifting, while the use of an undersized tubing will restrict the production potential due to increased friction resistance and introduce an unnecessarily large pressure drop into the system. Only by selecting an optimum tubing size can the friction pressure losses and potential liquid phase losses be minimised, whilst retaining the reservoir energy of the system.

In general, the optimum tubing size is the tubing size capable of maximising production under specified separator pressure or tubing head pressure (THP) conditions. While hydrocarbon condensate drop-out in the tubing is not anticipated in the Karish wells based on PVT, significant water drop-out could significantly impact well performance, and potentially the ability to restart a well after a shut-in. Therefore, it is imperative that in this work, that we anticipate and mitigate any such potential situations.

Using the PROSPER (PETEX) software discrete well VLP/IPR curves were compiled using a well completion of open hole gravel pack and production tubing of 7". From PVT standpoint the model used a "Dry & Wet Gas" compositional approach and the IPR model was the Petroleum Experts inflow option that uses a multiphase pseudo pressure function to model the reduction in well productivity resulting from increasing liquid saturation in the wells. The fluid vertical correlation assumed for this exercise was Petroleum Experts 5 (PE5) in order to reduce the potential instabilities through a calculation that does not use flow regime maps as a starting point.

The length of reservoir section must be sufficient to ensure delivery of ~200 mmscf several years after start-up, when it is anticipated that a well might fail either because of an integrity issue or through water breakthrough. Figure 6-20 present the sensitivity of the reservoir section of the open hole gravel pack on the achieved well gas rate at various reservoir pressures, assuming that the well head flowing pressure is at 240 bara. The "safe" area in green colour symbolises the well rates exceeding 200 mmscf/day and it is evident that a range from 20m to 30m, of reservoir section, gives the wider range for drop of reservoir pressure due to depletion.

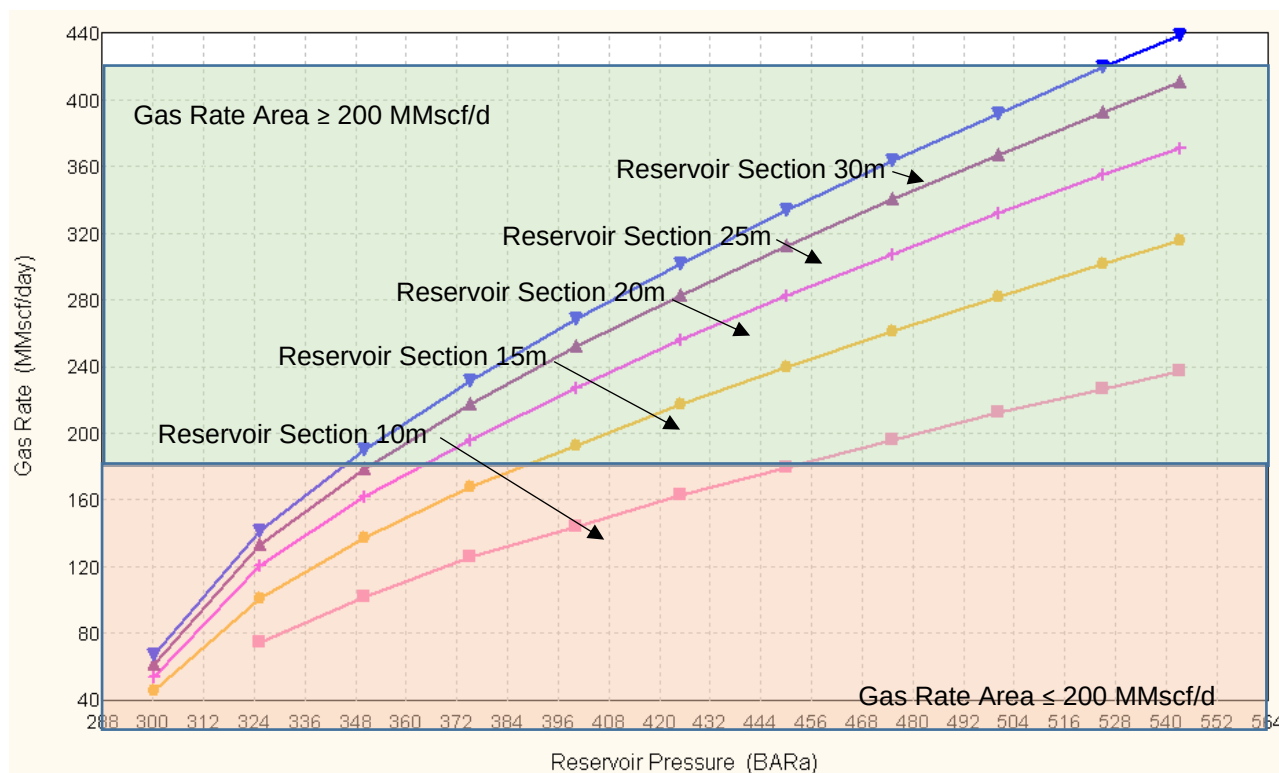


Figure 6-20 Reservoir Section Length Sensitivity

Figure 6-21 presents the results of the system analysis (VLP/IPR Curves) for a typical Karish well, using 7" production tubing and 25 meters of open hole gravel pack arrangement. Furthermore from this figure the shut-in well head pressure at initial reservoir pressure is estimated at 460 bara.

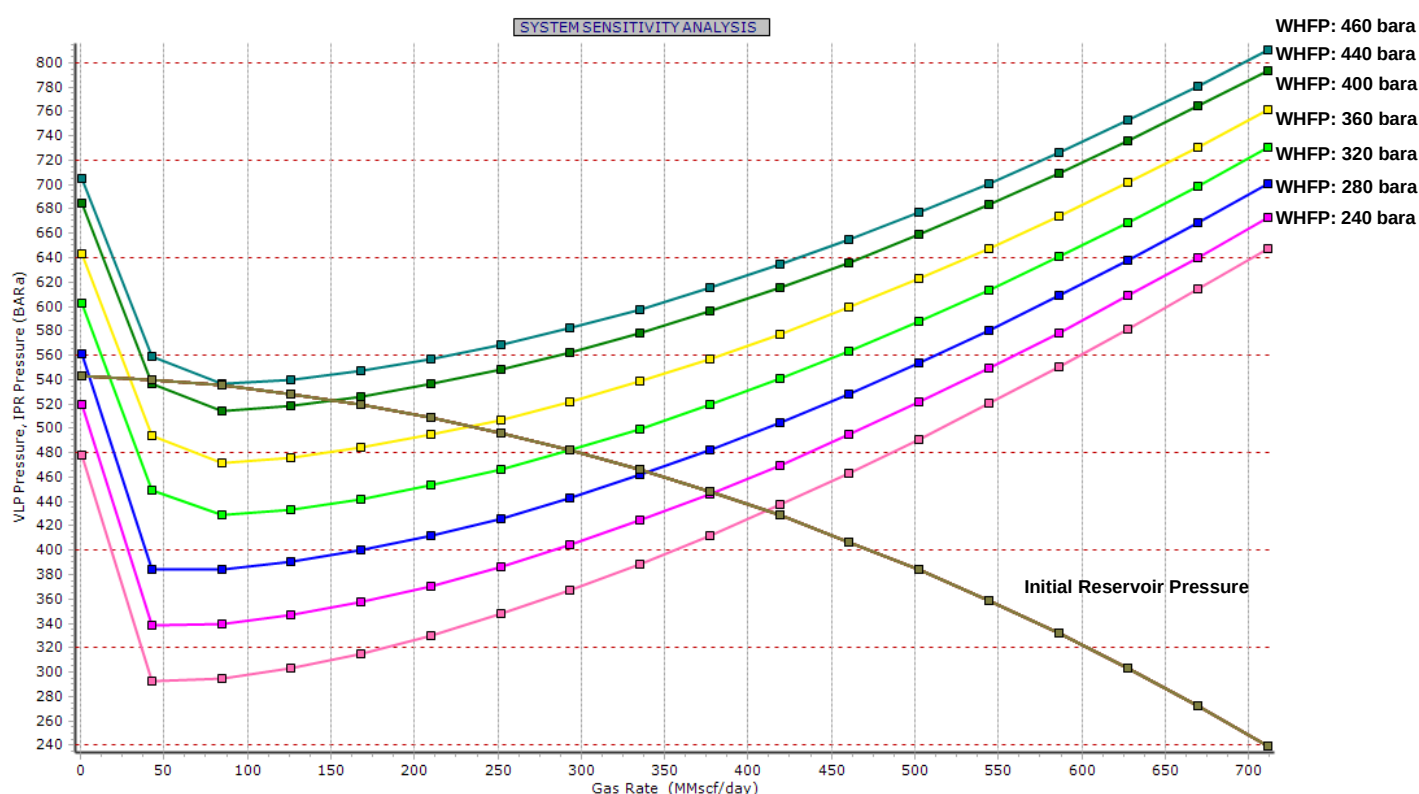


Figure 6-21 Karish Well Analysis IPR/VLP at initial reservoir pressure

6.1.5.1 Tubing Size Evaluation

Four tubing sizes were considered and evaluated for the Karish field development, i.e.: 5", 5-1/2", 7" and 7-5/8". Of these, the 5" and 7-5/8" tubing sizes were discounted early in the process with the 5" tubing size predicted to exceed erosional velocity limits under the projected tubing head pressure (THP) and flow rate operating envelope, based on an estimation of the erosional velocity limit using the equation proposed by Salama (1988), while the 7-5/8" was discounted due to the fact that it significantly increases the liquid loading risk above that seen in a 7" tubing without significant benefit in terms of reduced back pressure. Of the 5-1/2" (4.9" ID) and 7" (6.094" ID) tubing sizes both are capable of delivering the ~200 mmscf/day maximum daily production requirement, whilst not exceeding acceptable erosional velocities within the projected THP and flow rate operating envelope. Having thus established the overall suitability of both the 5-1/2" and 7" tubing sizes, a produced gas water ratio (WGR) sensitivity was conducted on the two tubing sizes over the expected range of THP and reservoir pressure values using the KM-2 well location as a reference. The essence of this analysis was to evaluate the impact of water influx (production) on well performance over the life of the field. Figure 6-27 to Figure 6-29 present a summary of the findings.

Figure 6-22 and Figure 6-23 show the minimum unloading rates determined for both tubing sizes, whilst Figure 6-24 presents the final cumulative production profiles also obtained for the two tubing sizes, using KM-2 as a reference case. These results mirror those obtained for the other two Karish wells.

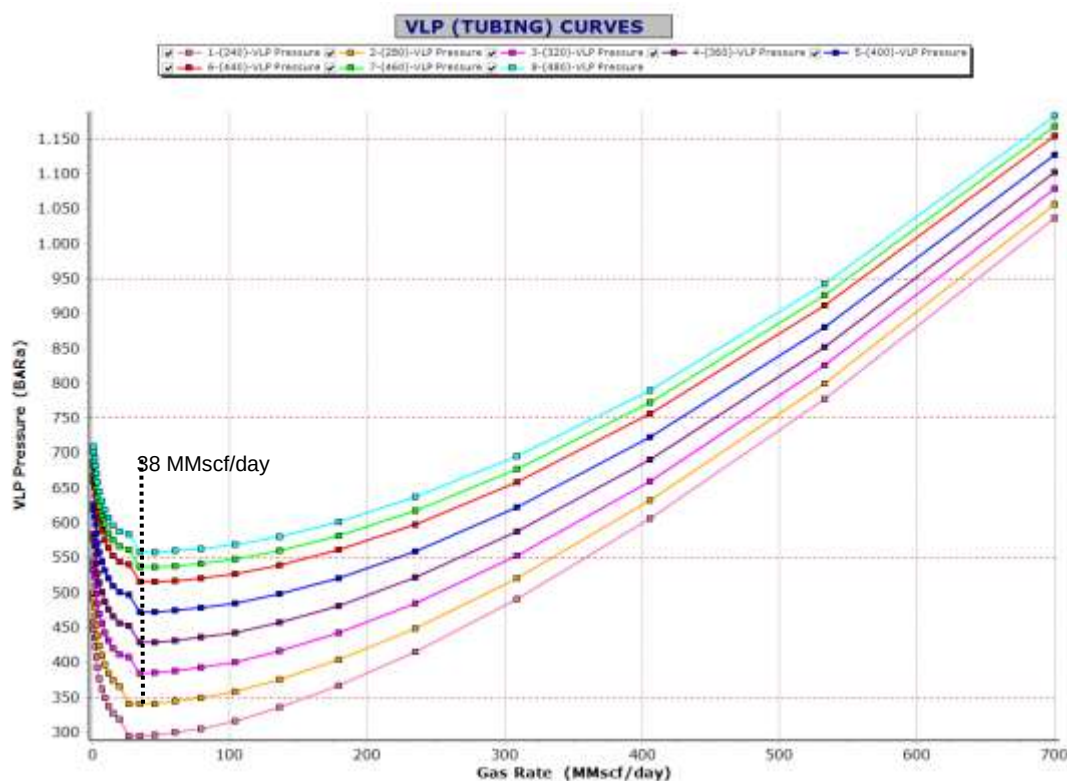


Figure 6-22 5 -1/2" Tubing Minimum Stable (Unloading) Rate

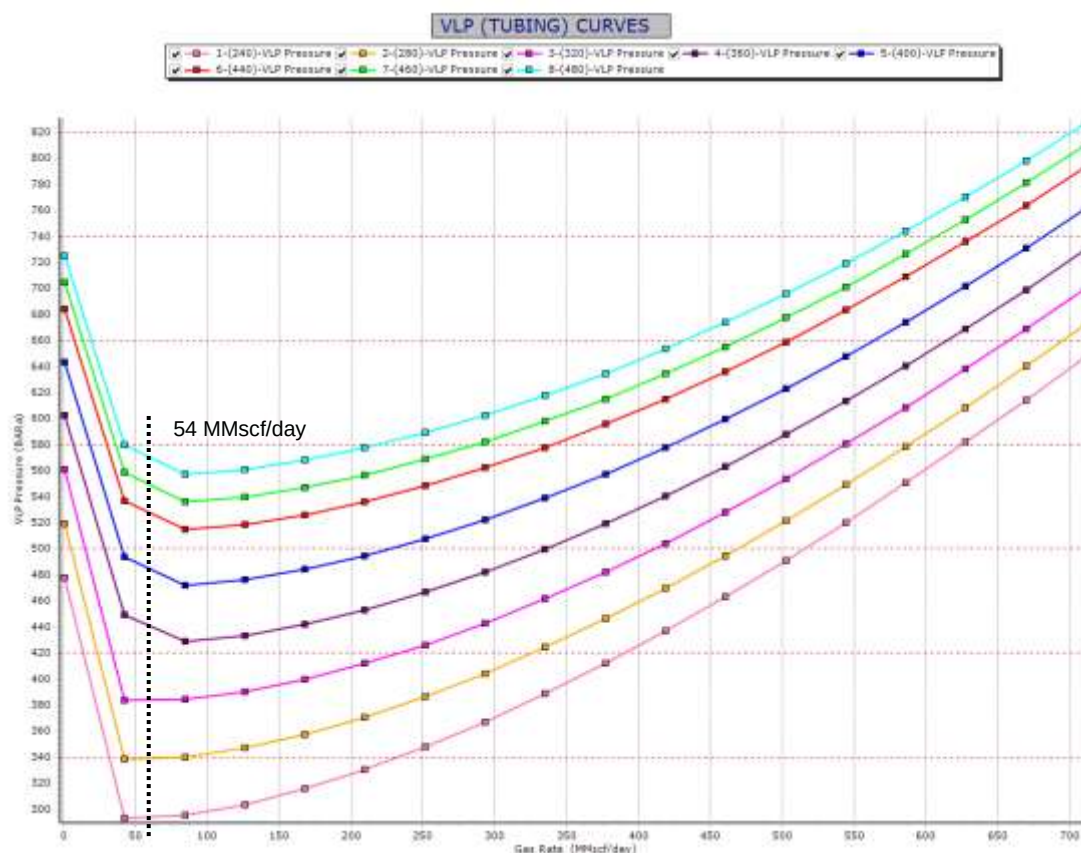


Figure 6-23 7" Tuning Minimum Stable (Unloading) Rate

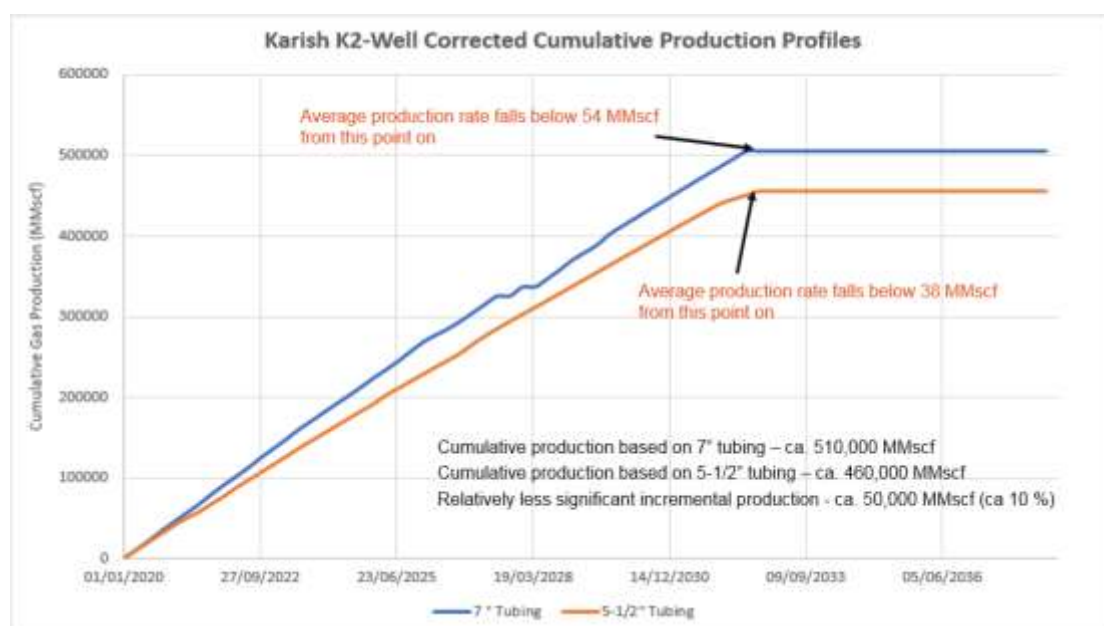


Figure 6-24 Karish-2 Well - Cumulative Production Profiles

Based on the large frictional pressure drop predicted for the 5-1/2" and the impact that this has on the ability to flow at the required 200 mmscf/d several years into the future the 7" tubing size was selected as the most suitable to cover the expected life of field operating conditions. Furthermore the P/Q Curves shown in Figure

6-25 and Figure 6-26 verify that the 7" tubing size is superior choice, since can provide the required 200 mmscf/day for most of the well's life.



Figure 6-25 Karish PQ Curves

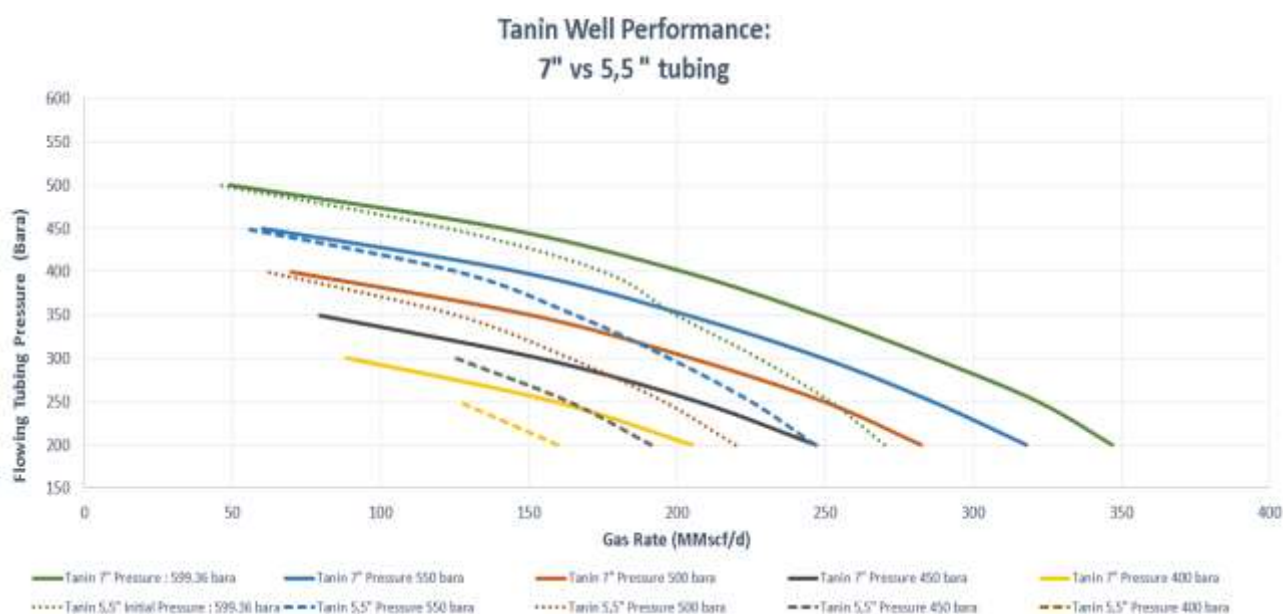


Figure 6-26 Tanin PQ Curves

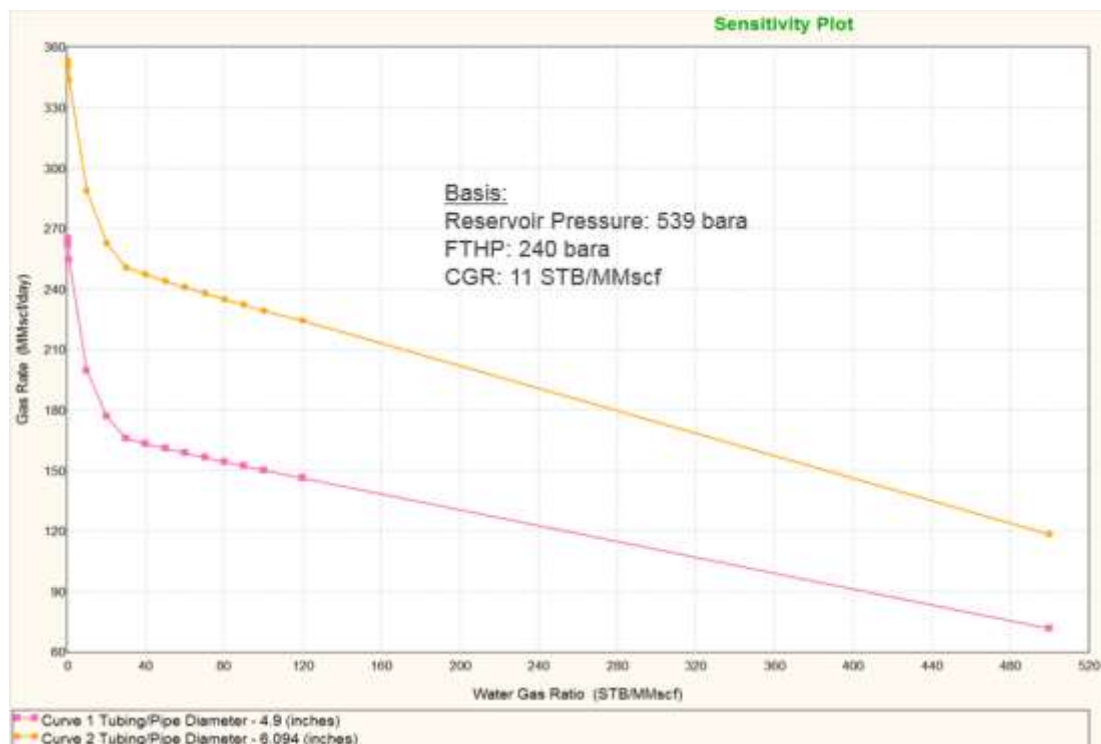


Figure 6-27 Impact of Water Production on Well Performance - Case (1)

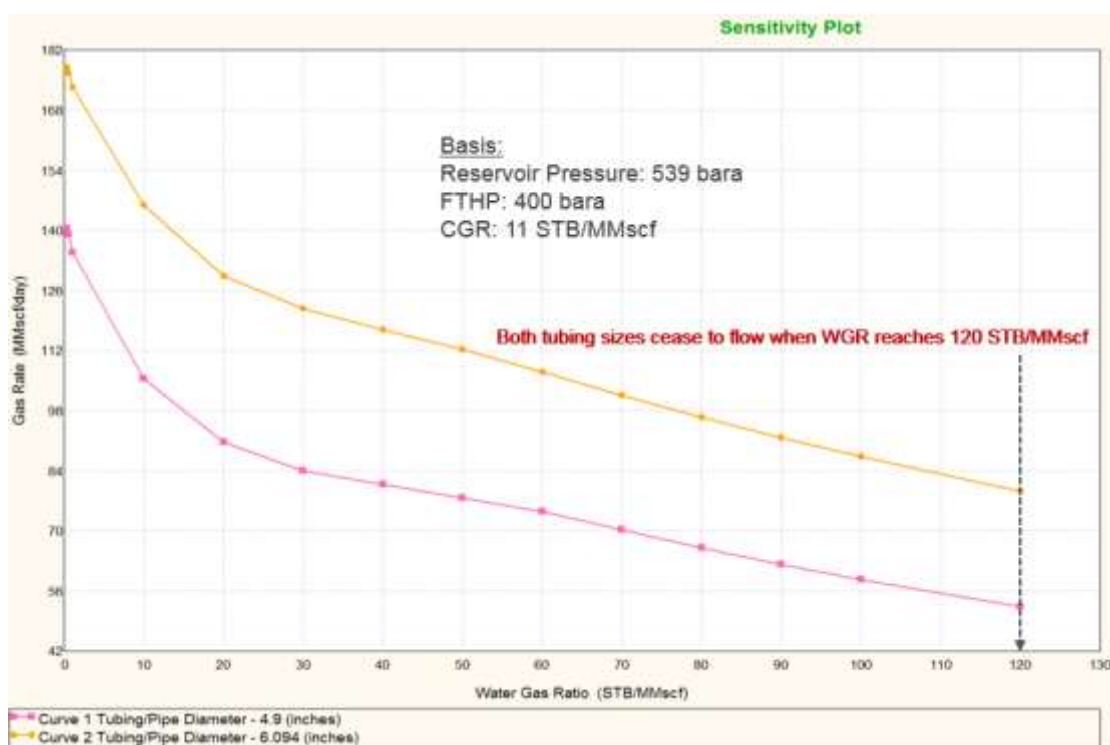


Figure 6-28 Impact of Water Production on Well Performance - Case (2)

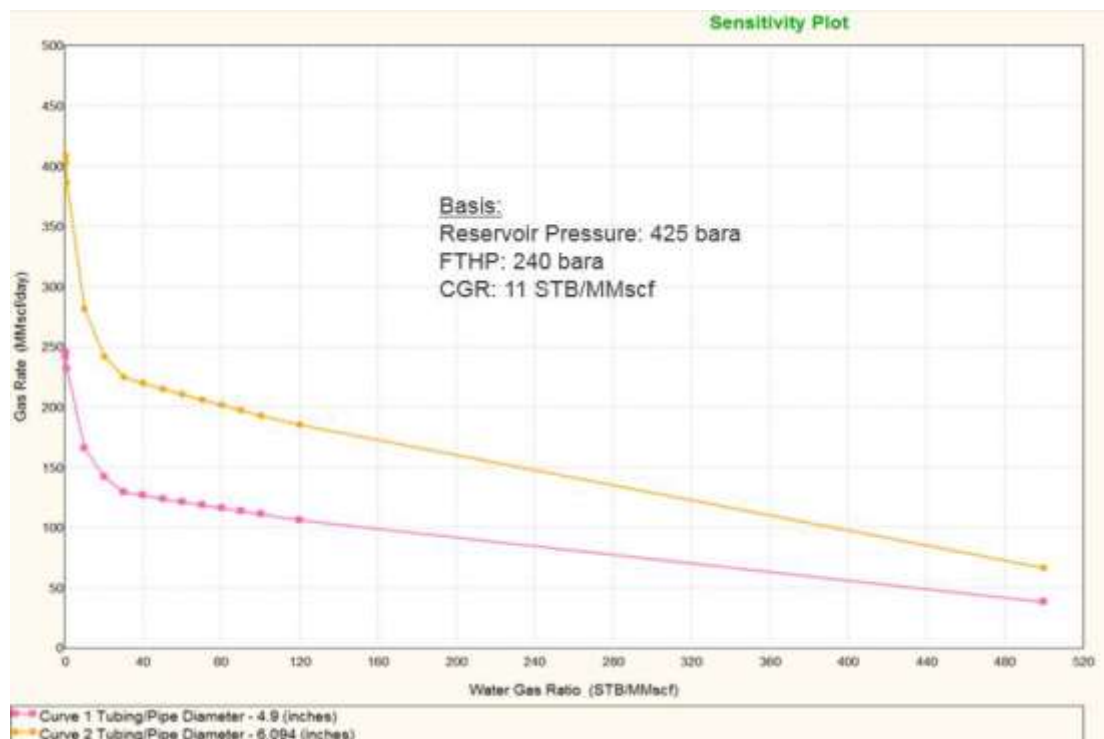


Figure 6-29 Impact of Water Production on Well Performance - Case (3)

In addition Figure 6-27 to Figure 6-29 demonstrate that the 7" tubing size offers superior flow performance over the 5-1/2" tubing under comparable circumstances, owing to the increased frictional pressure losses attributable to the smaller 5-1/2" tubing. However, it also shows depreciating well performance for both tubing sizes as WGR increases, with the possibility of the well ceasing to flow depending on the prevailing conditions of FTHP and reservoir pressure (Figure 6-28).

6.1.6 Karish Temperature Profile

Karish well temperature profile was analysed via PROSPER rough approximation and FTHT predictions were calibrated against WELLCAT and PROSPER enthalpy model predictions. From the analysis performed WELLCAT and PROSPER enthalpy model FTHT predictions fall within the same ballpark.

The analysis outlines that well FTHT is a function of rate, flow regime and tubing size and thus insensitive to reservoir pressure, while the estimated fluid temperature profile is a function of fluid flow rate, fluid specific heat capacity, tubing inlet temperature and heat transfer to / from the formation.

Figure 6-30 shows that Prosper rough approximation is insensitive to tubing pressure profile, since the temperature plot at two different THPs (200bara and 400bara) overlay each other indicating there is no difference. Therefore PROSPER rough approximation was found not accurate in a predictive mode, so has not adopted. Furthermore Figure 6-30 shows that the WELLCAT predicted tubing head temperature, and by implication the tubing temperature profile is different for each FTHP.

Figure 6-31 and Figure 6-32 show that FTHT is sensitive to WGR, as it increases with increasing values of WGR and insensitive to CGR within the expected CGR range (10 – 14 STB/mmscf and 100 – 200 mmscf / day)

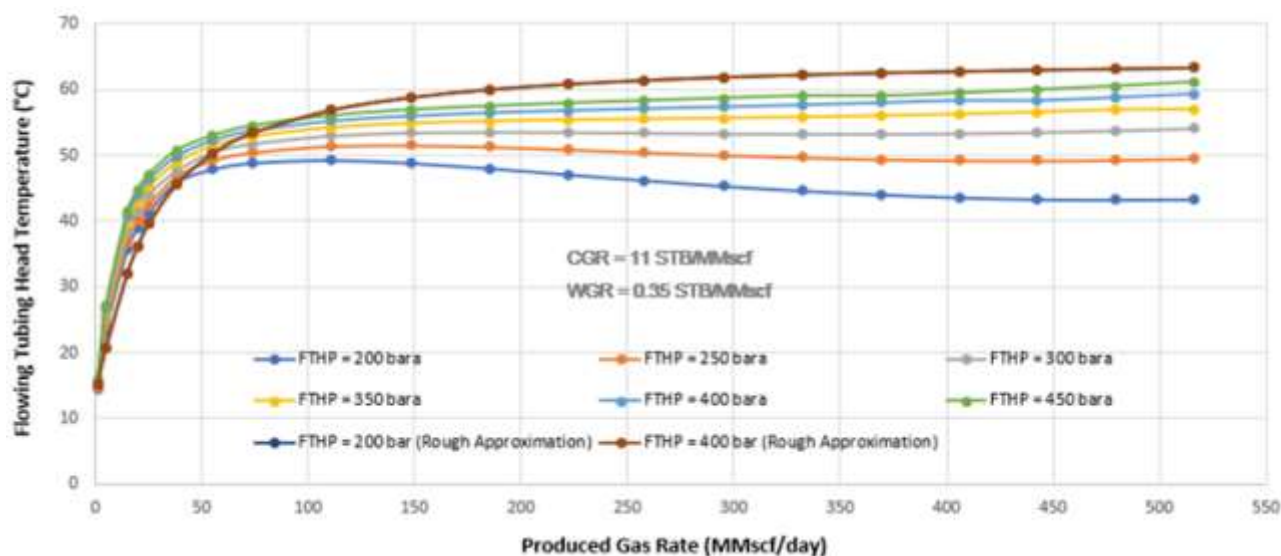


Figure 6-30 Karish Flowing Tubing Head Temperature Performance Plot

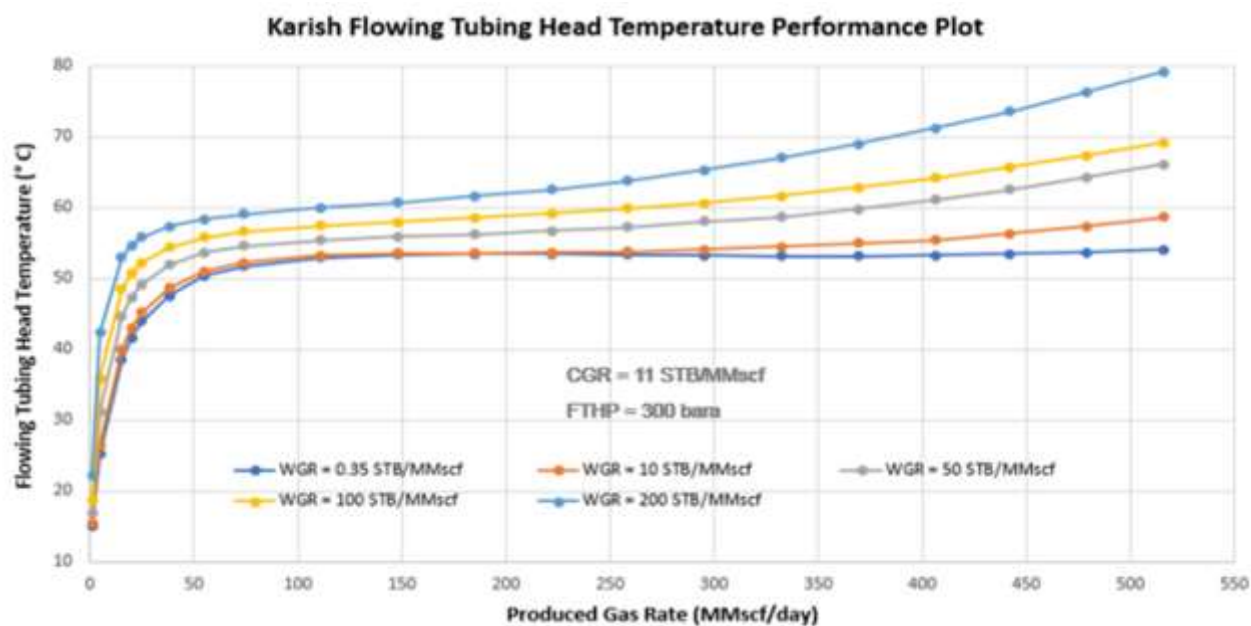


Figure 6-31 Karish Flowing Tubing Head Temperature at FTHP:300 bara and CGR:11STB/mmscf

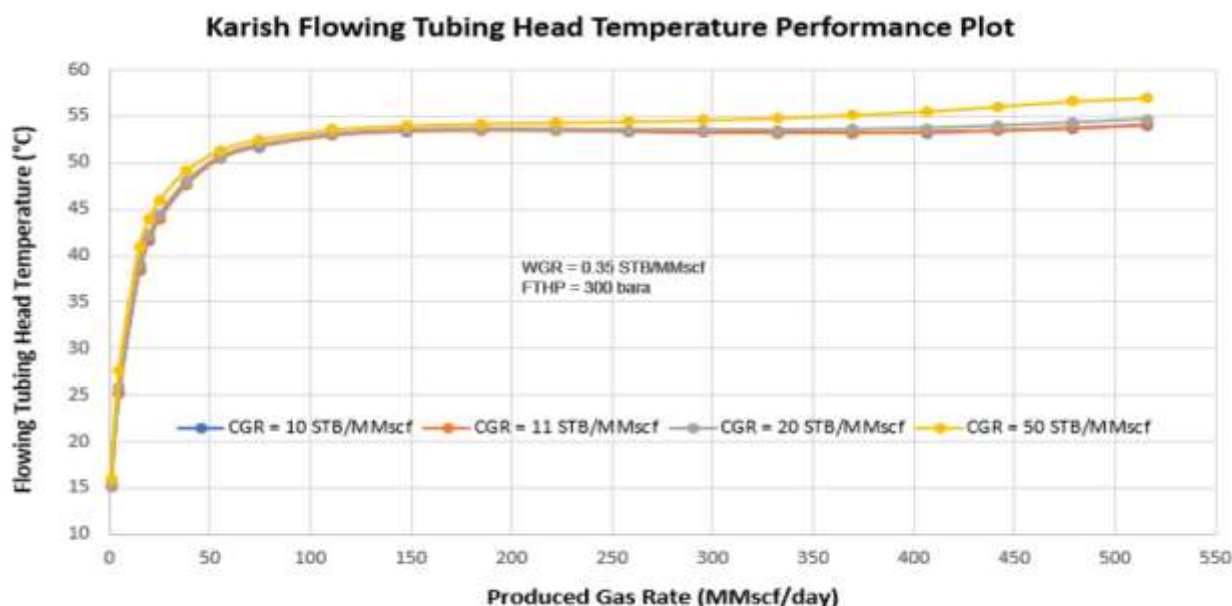


Figure 6-32 Karish Flowing Tubing Head Temperature at FTHP: 300 bara and WGR:0,35

6.1.7 Well Test Analysis

No Drill Stem Test (DST) was performed on the Karish-1 exploration well, so history matching of the dynamic model was not feasible.

6.1.8 Well and Production Facility Constraint

The production forecasts were modelled by imposing maximum fluid handling constraints and tubing head pressure (THP) limitations.

Table 6-10 below, summarizes the well and production facility modelling assumptions.

FACILITY AND WELL MODELLING CONSTRAINT PARAMETERS	VALUE	UNITS
Max field gas prod. rate	290	mmscf/day
Max field water gas ratio	10	stb/mmscf
Min well THP	3481	psia

Table 6-10: Facility and Well Modelling Constraints applied in Karish field simulation model

6.1.9 Karish Simulation Model

Results from the Karish model have been primarily used to understand how to optimise the development of the Karish Main accumulation. Since the Karish North and Karish East accumulations are as yet unpenetrated they are prospective resources and carry an element of risk that precludes them from forming part of the current forward development plan.

In the modelling results which are discussed in the following section, the work has focused on understanding the optimal location and completion strategy for the wells; i.e. to maximise the recovery of the gas reserves that lie within the Karish Main area and to defer the production of the aquifer water until as late as possible. With three main fault segments subdividing this part of the field, it is evident that the forward development plan will need a minimum of one well per segment, i.e. 3 wells.

In order to understand how the Karish Main depletes, sensitivities have been run in which aquifer strength, reservoir permeability, critical and trapped gas saturation, well location, completed section, fault sealing and production constraints have been varied. The results of this work are outlined in the following sections.

6.1.9.1 Best-technical Case

6.1.9.1.1 Initialisation

During the initialization stage the fluid in-place as calculated by Eclipse for layers C&D were compared with the static model. The differences were around 4 % (layer C) and 5 % (layer D). Pore volumes multipliers of 1.064 and 1.043 were applied to reduce the differences.

Table 6-11 shows the GIIPs of the Petrel static model and Eclipse dynamic model.

Table 6-11: Karish main GIIP comparison between Petrel static model and Dynamic simulation model (Eclipse)

	PETREL STATIC MODEL	ECLIPSE MODEL
Layers	ORIGINALLY IN PLACE GIIP[Bscf]	ORIGINALLY IN PLACE GIIP[Bscf]
Karish Main	Karish Main	Karish Main
C	2040	2033
D	362	360
Total	2402	2393

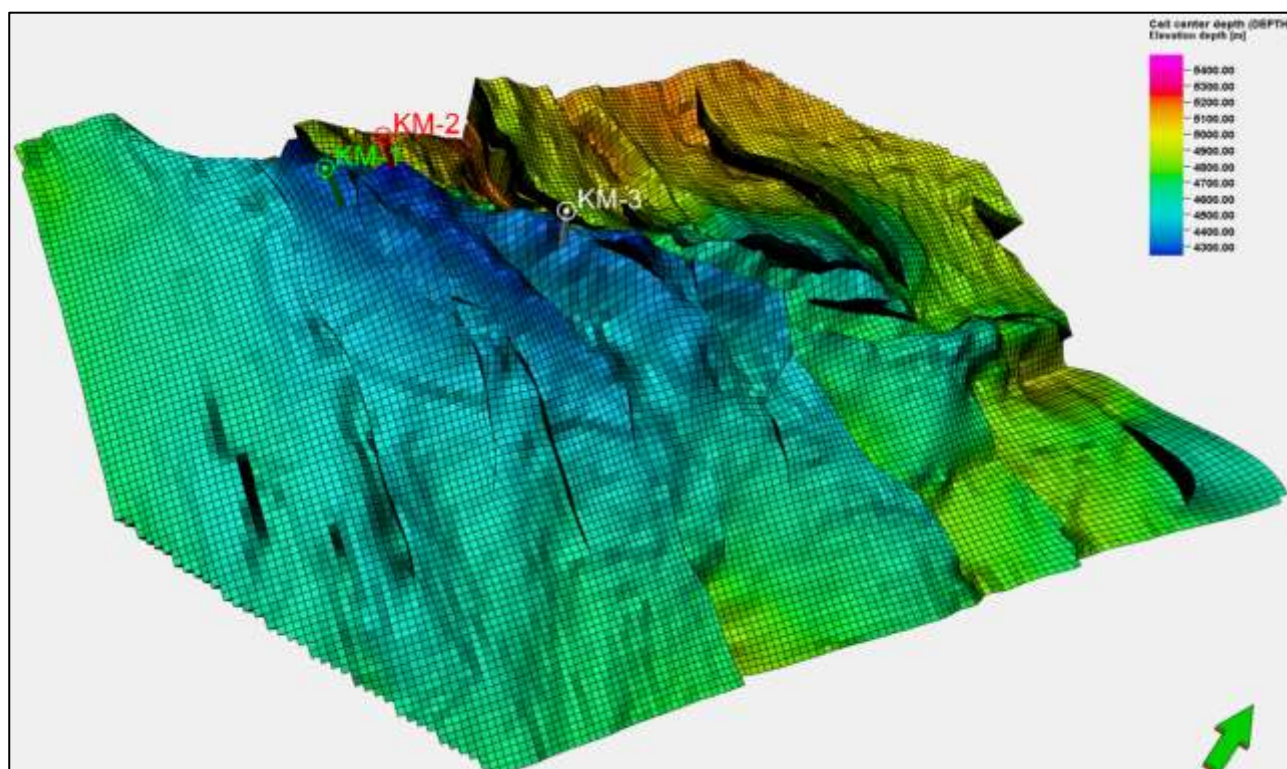


Figure 6-33 Karish field well locations on depth map on layer C (top)

6.1.9.1.2 Best-technical Case Simulation Run

The Best-technical case has been defined with all the input data presented in above sections and as the most recently geological and dynamic interpretation. The other runs are then referenced to this run to ascertain whether the changed parameter gives a better or worse production profile.

The main assumptions for the Karish field Best-technical case:

- Two major faults are sealing as shown in Figure 6 4
- All minor internal faults in Karish Main area are not sealing
- Rock compressibility of 1.5241-05 1/psi was selected as typical for this type of unconsolidated formations. See reference number [1].
- Analytical Fetkovich aquifer is connected to only the outer edges of C&D layers.
- No downtime assumed. All wells are assumed to be available from the start
- C sand and communication with D sand
- Grid rock properties with the assumption intra-reservoir shale transmissibility for all layers A&B&C&D
- Aquifer sized to match Pressure drop of 200 psia based on Tamar analogue field as is shown in Figure 6 40
- Residual gas saturation (Gas trap) of 0.25
- Layers A&B were disabled
- Three vertical wells located (KM-1, KM-2 and KM-3) on the top of the structure were defined to develop the prospect as is shown in Figure 6 30,
- Well rates are controlled by vertical lift tables, with a flowing THO limit of 3481 psia,
- Flow constraint of field-maximum gas rate of 290 mmscf/day and water gas ratio of 10 stb/mmscf.

Figure 6-34, Figure 6-35, Figure 6-36 and Figure 6-37, present map with the results of the gas saturation from the beginning of the simulation 01 Jan 2020 to 01 Jan 2039 for layers C and D respectively.

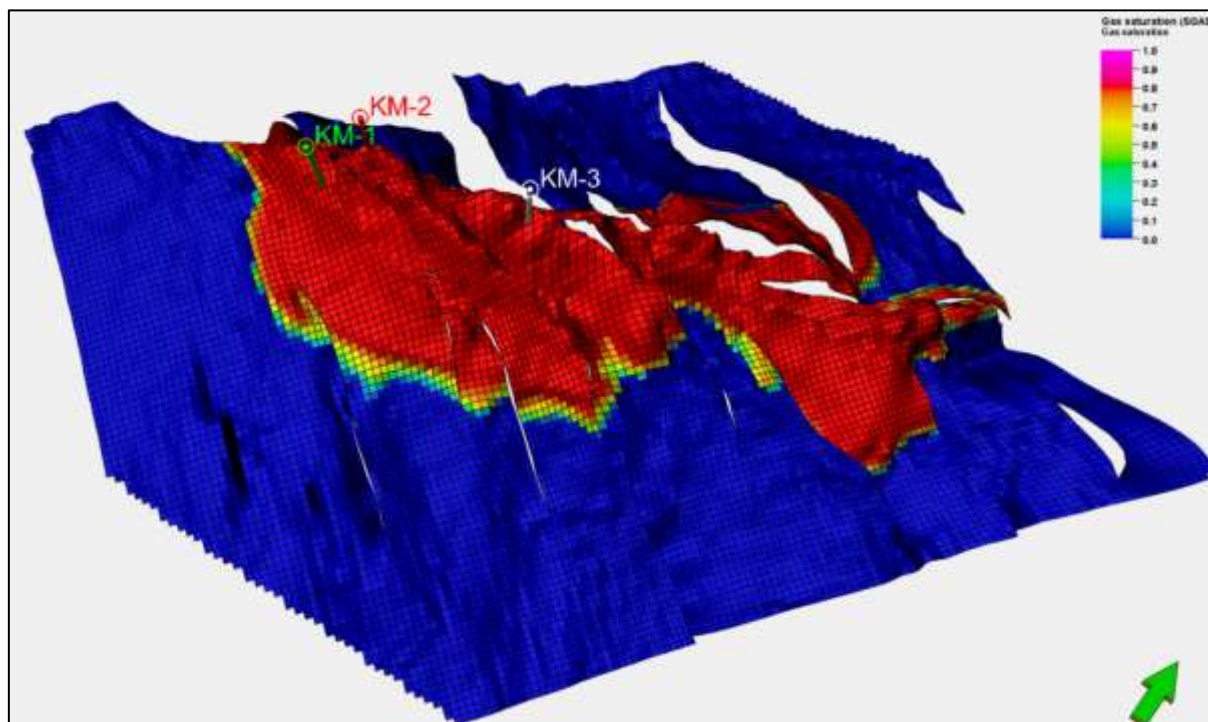


Figure 6-34 Initial gas saturation map on layer C (top) at 01 Jan 2020

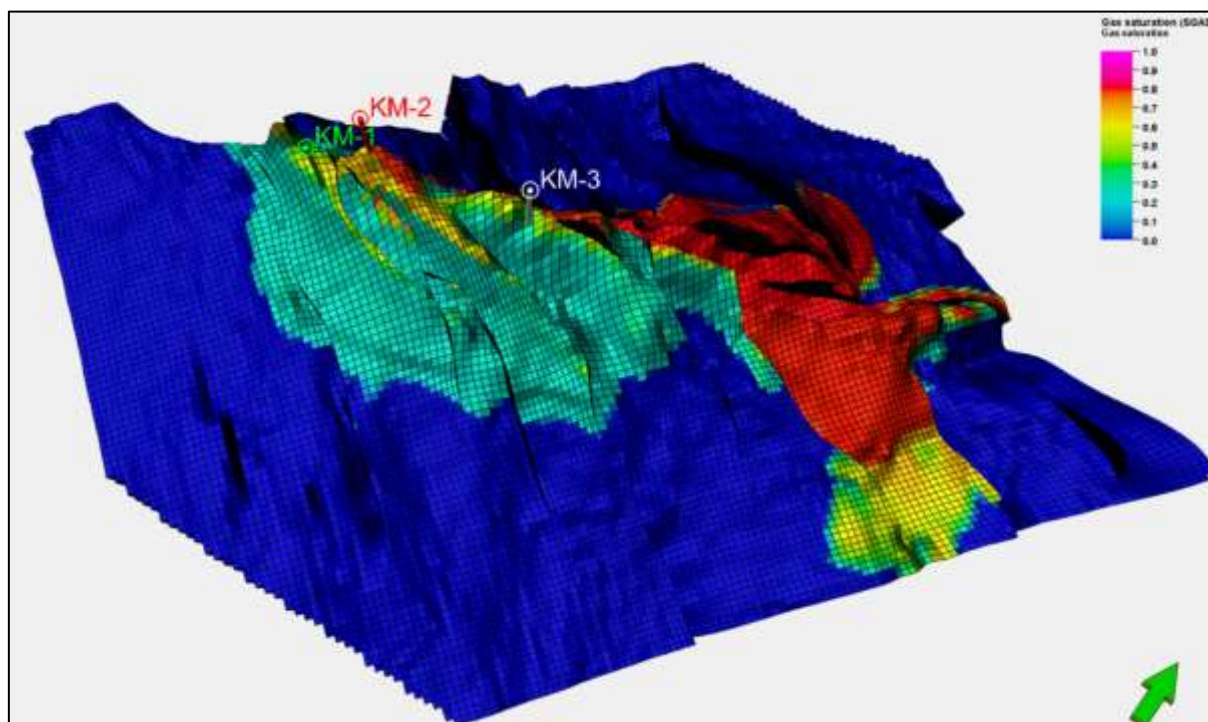


Figure 6-35 Final gas saturation map on layer C (top) at 01 Jan 2039

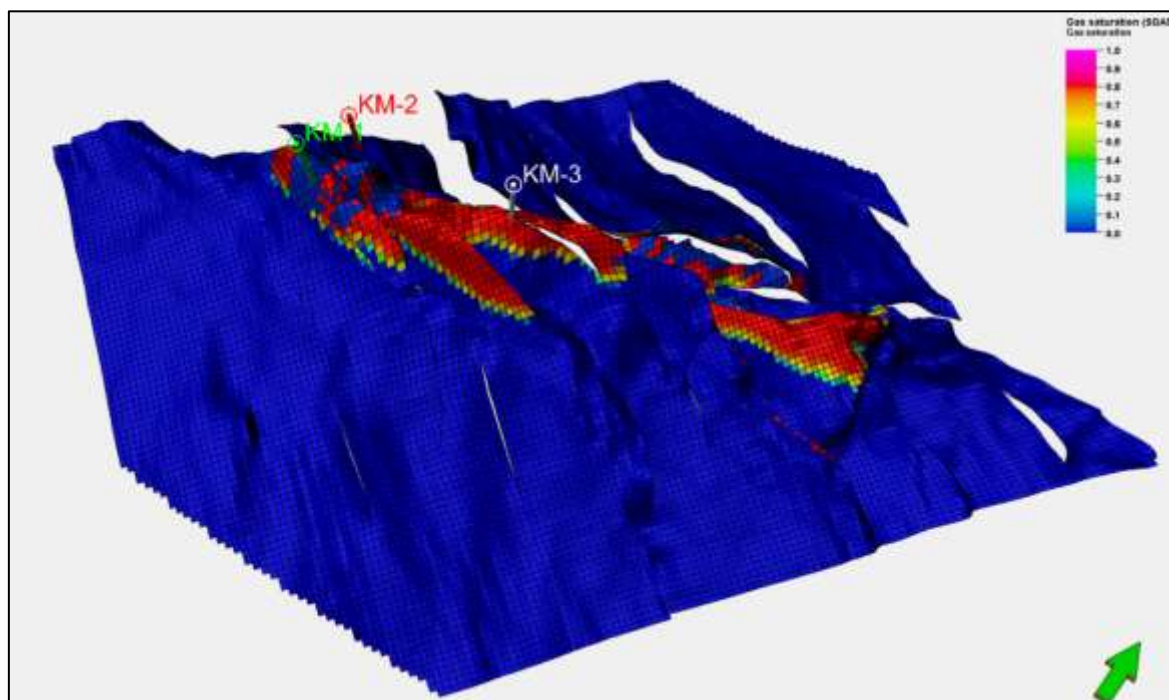


Figure 6-36 Initial gas saturation map on layer D (top) at 01 Jan 2020

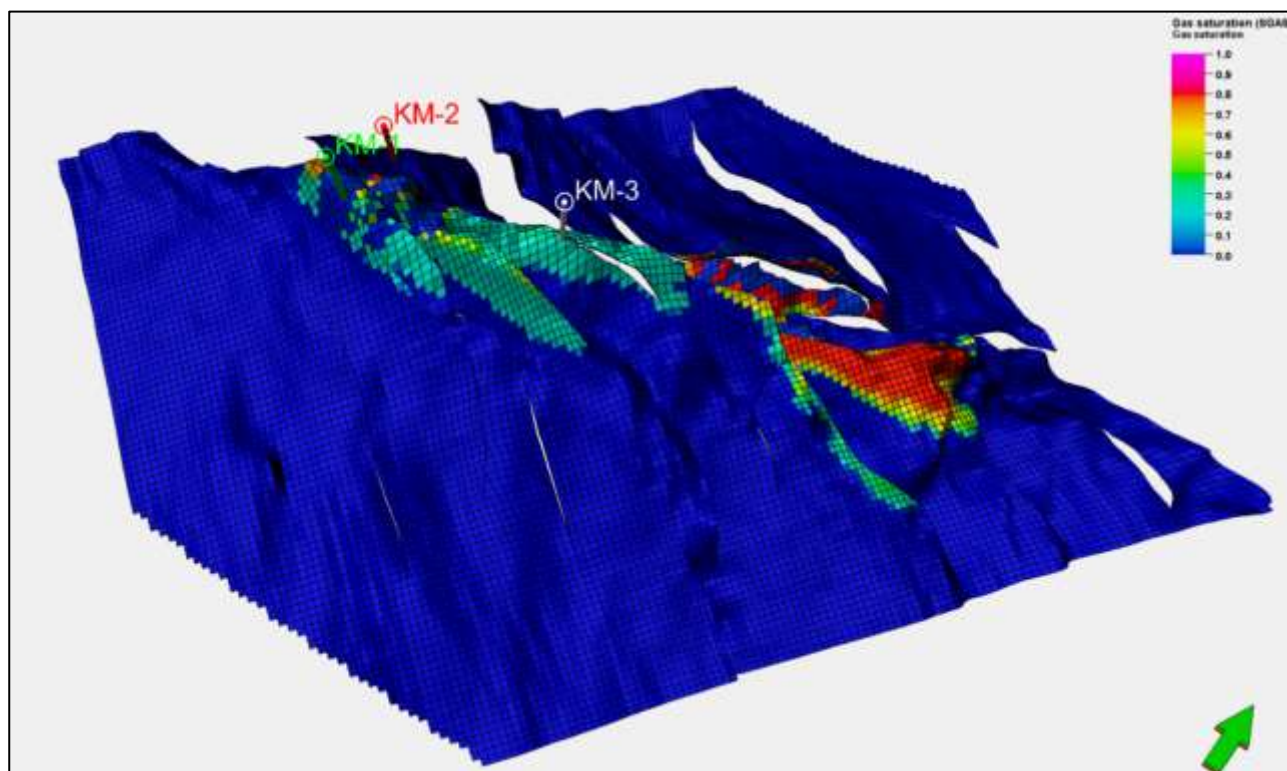


Figure 6-37 Final gas saturation map on layer D (top) at 01 Jan 2039

The reservoir pressure obtained at the final of the Best-technical case forecast is presented in Figure 6-38.

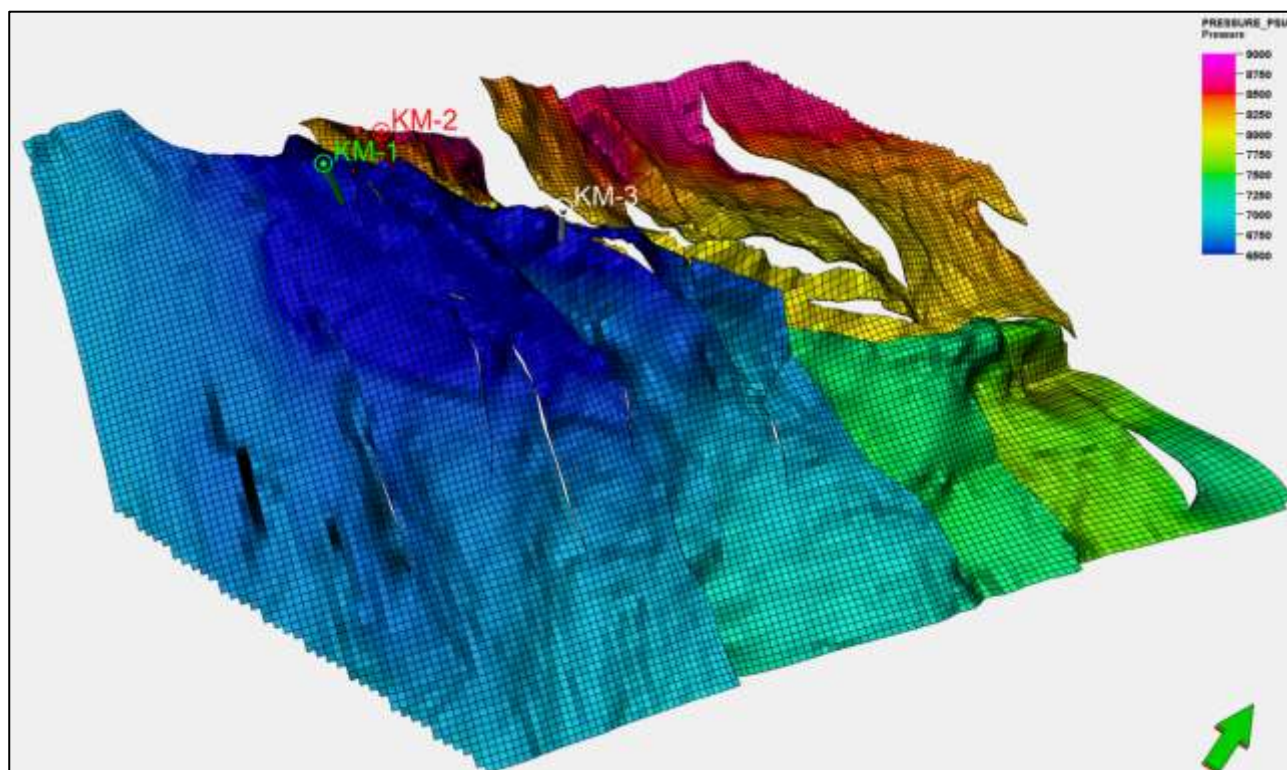


Figure 6-38 Final reservoir pressure map on layer D (top) at 1/1/39

Two sets of FIP (by segment) regions were established in the eclipse model to report the fluid in place by segment and by layer C/D. To report the fluid for layer C the segments considered are the following:

- Segment 1 is compound by the region 1 where KM-1 is located,
- Segment 2 corresponds to the region 2 where KM-2 is located,
- Segment 3 is represented by region 3 where well KM-3 is located.

To report the fluid for layer D the segments considered are the following:

- Segment 4 is compound by the region 1 where well KM-1 is located,
- Segment 5 corresponds to the region 2 where well KM-2 is located,
- Segment 6 by is represented by region 3 where well KM-3 is located.

Figure 6-39 presents the segments 1 (purple colour), segment 2 (light blue colour) and segment 3 (green colour) for the layer C.

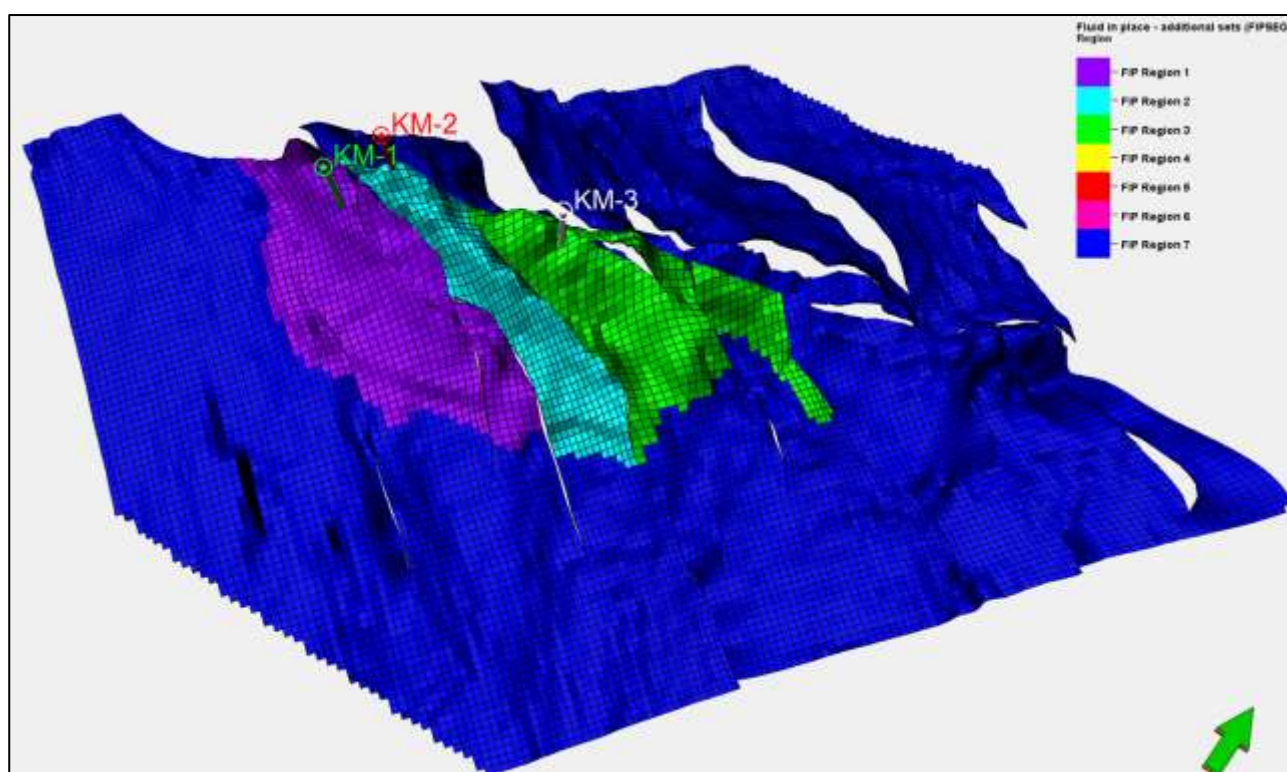


Figure 6-39 FIP regions definition for Layer C (Segment 1, Segment 2, Segment 3)

Figure 6-40 presents the segments 4 (yellow colour), segment 5 (red colour) and segment 6 (magenta colour) for layer D.

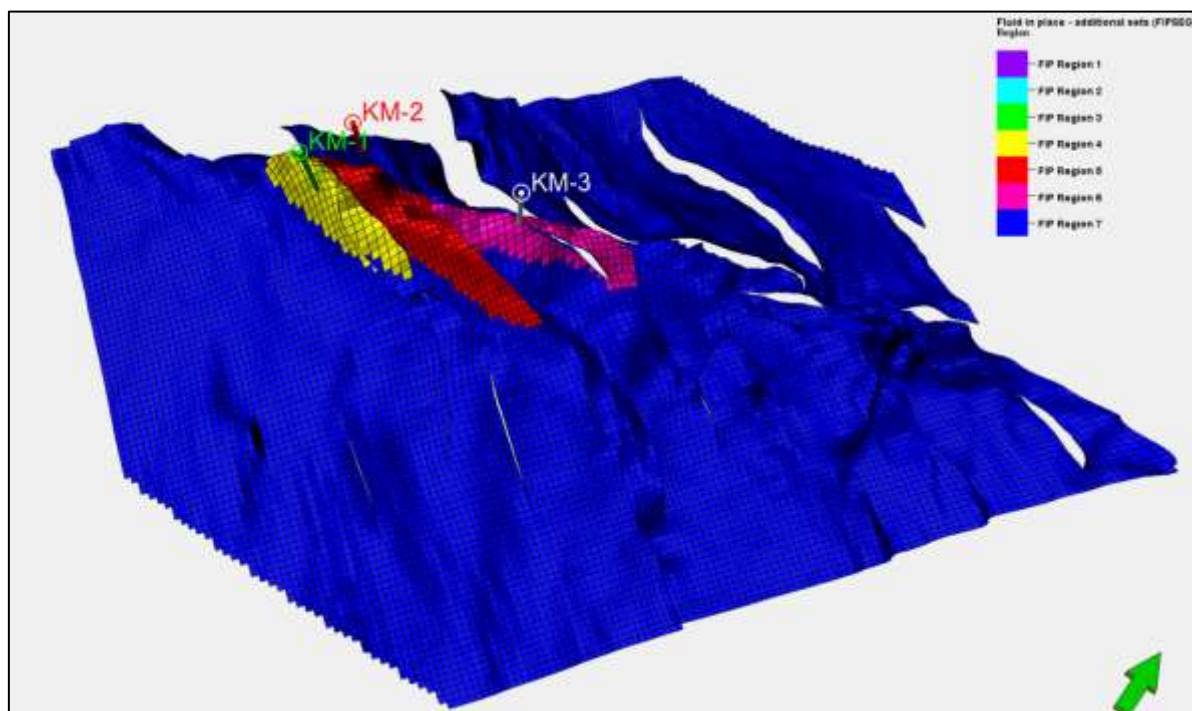


Figure 6-40 FIP regions definition for Layer D (segment 4, segment 5 and segment 6)

The gas produced volumes, for the defined Best-technical case are presented in Table 6-13: Best-technical case Karish main recoverable gas volumes results by segment for layer C and D. The results have been reported for layers C and D and by segment, where the wells (KM-1, KM-2 and KM-3) are located, as is shown in Figure 6-39 and Figure 6-40. The forecast production plots are shown in Figure 6-41, Figure 6-42 and Figure 6-44.

Table 6-12: Best-technical case Karish main GIIP results by segment for layer C and D

GIIP (Bscf)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	834	555	645	2033
D sand	87	149	124	360
Total Field (C&D)	2393			

Table 6-13: Best-technical case Karish main recoverable gas volumes results by segment for layer C and D

Gas Recoverable volume (Bscf)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	590	365	428	1383
D sand	58	100	84	242
Total Field (C&D)	1625			

Table 6-14: Base case Karish main gas recovery factor results by segment for layer C and D

Gas Recovery Factors (%)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	70.8%	65.8%	66.3%	68.0%
D sand	66.9%	67.3%	67.7%	67.3%

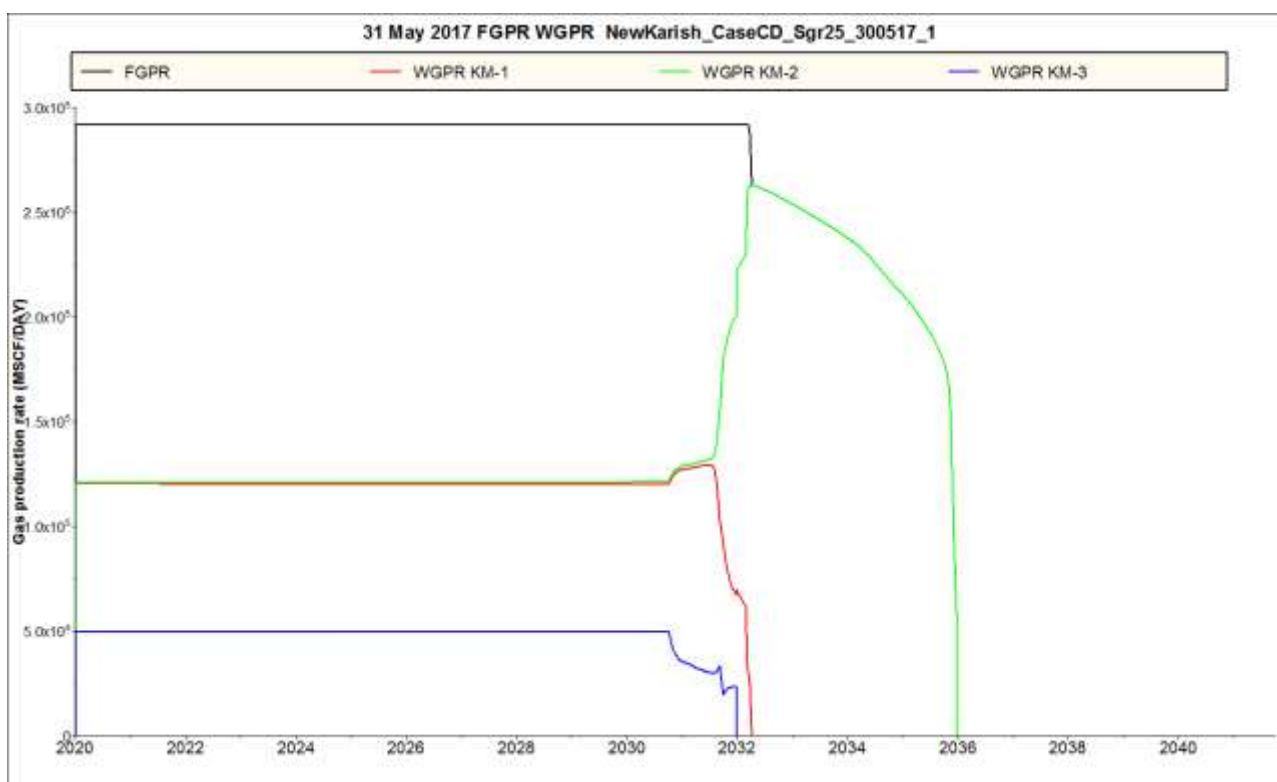


Figure 6-41 Best-technical case Karish Field and well gas rate forecast

Figure Note: KM-3 and KM-1 end dates aligned. Further production rate optimisation required to align KM-2 end date.

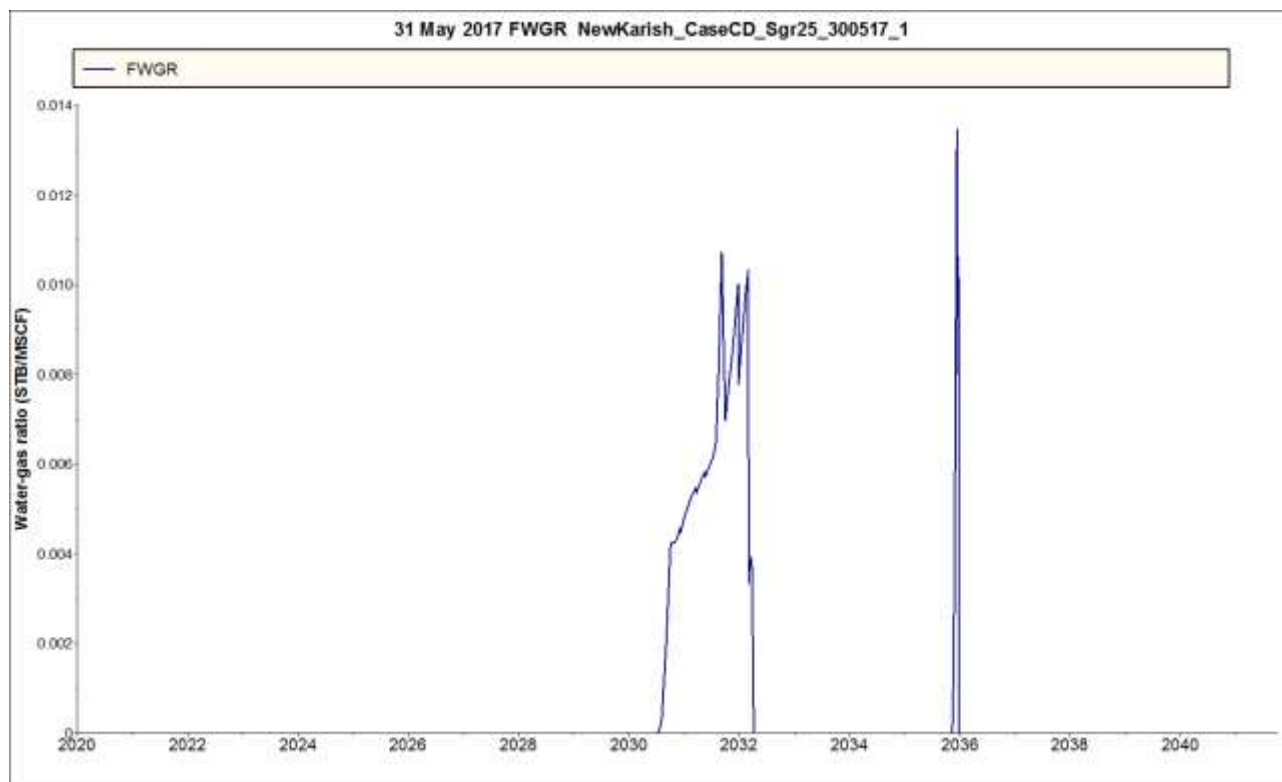


Figure 6-42 Best-technical case Karish field WGR forecast

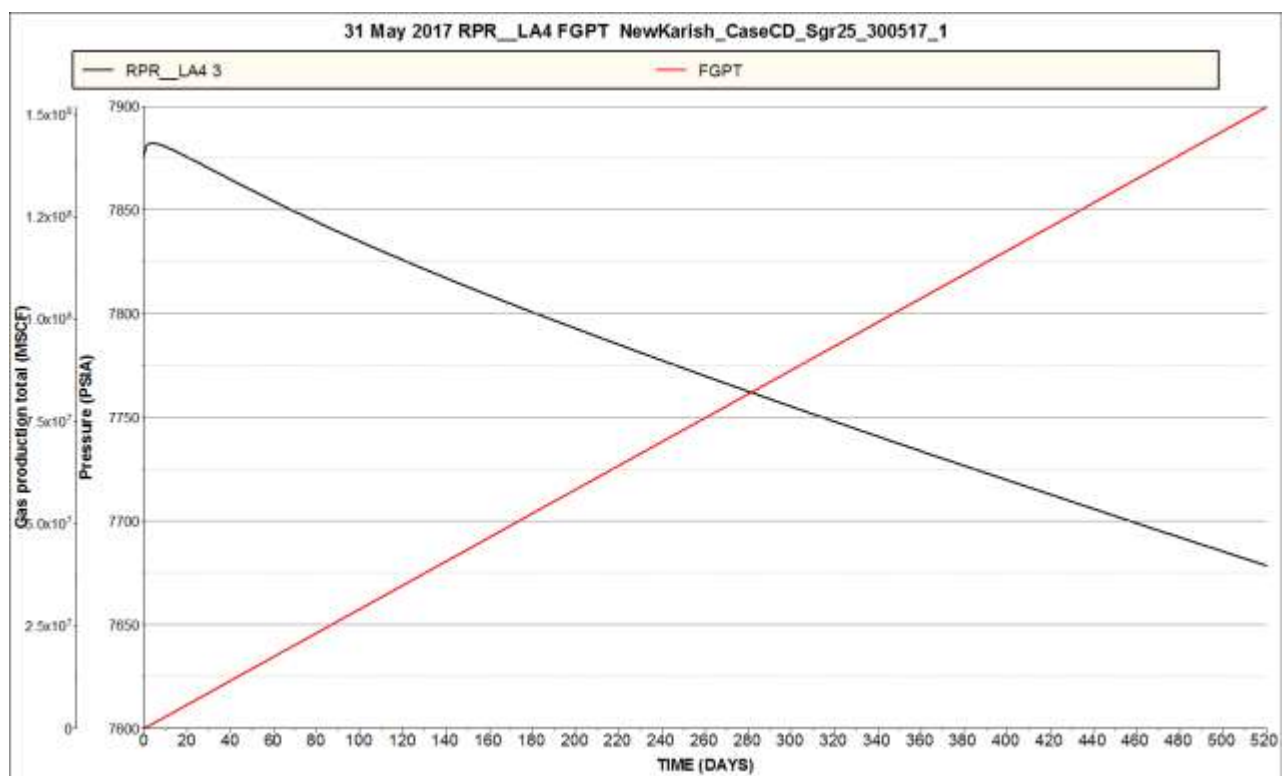


Figure 6-43 Best-technical case Karish Field pressure drop (200 psia) forecast

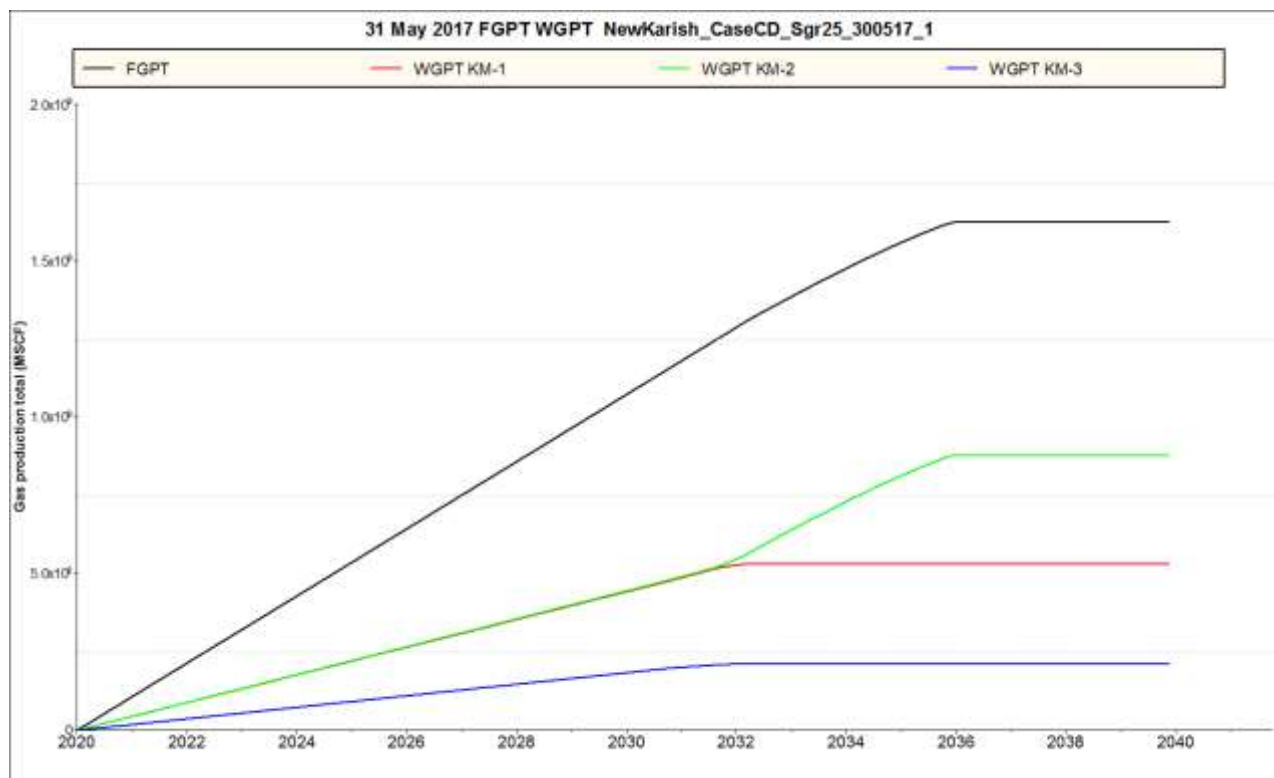


Figure 6-44 Best-technical case Karish Field and well gas total production forecast

6.1.9.2 Sensitivities

6.1.9.2.1 Simulation Runs

Once the Karish Best-technical case was generated a limited number of sensitivity runs were made, modifying the initial water saturation, residual gas saturation, the vertical to horizontal permeability ratio, the Water to Gas Ratio (WGR) and Fetkovich aquifer parameters. And was concluded that Sgr has the biggest impact parameter on gas recovery and by this reason two cases were generated for 0.20 and 0.30 residual gas saturation.

Table 6-15 outlines the selected parameter that were used for sensitivity analysis and the results. The recovery factor comparison for these cases are given in Figure 6-45.

Table 6-15: Parameters used for sensitivity analysis and the results

Parameter	Ranges	Case	Total Gas (Bscf)	Rf C sand	Rf D sand	Rf Total field
Swcr	0.20	downside	1622	67.9	67.2.4	67.8
	0.32	reference	1625	68.0	67.3	67.9
	0.44	upside	1628	68.1	67.4	67.8
Sgr	0.20	downside	1484	62.2	61.3	62.0
	0.25	reference	1625	68.0	67.3	67.9
	0.30	upside	1764	73.8	73.3	73.7
Kv/Kh	0,10	downside	1625	68.0	67.3	67.9

	0.50	reference	1625	68.0	67.3	67.9
	1.00	upside	1625	68.0	67.3	67.9
GIIP	-15%	downside	1625	68.0	67.3	67.9
	"Best tech"	reference	1625	68.0	67.3	67.9
	+15%	upside	1625	68.0	67.3	67.9
Minor faults	Non-sealing	reference	1625	68.0	67.3	67.9
	Sealing	downside	1485	66.5	37.3	62.0

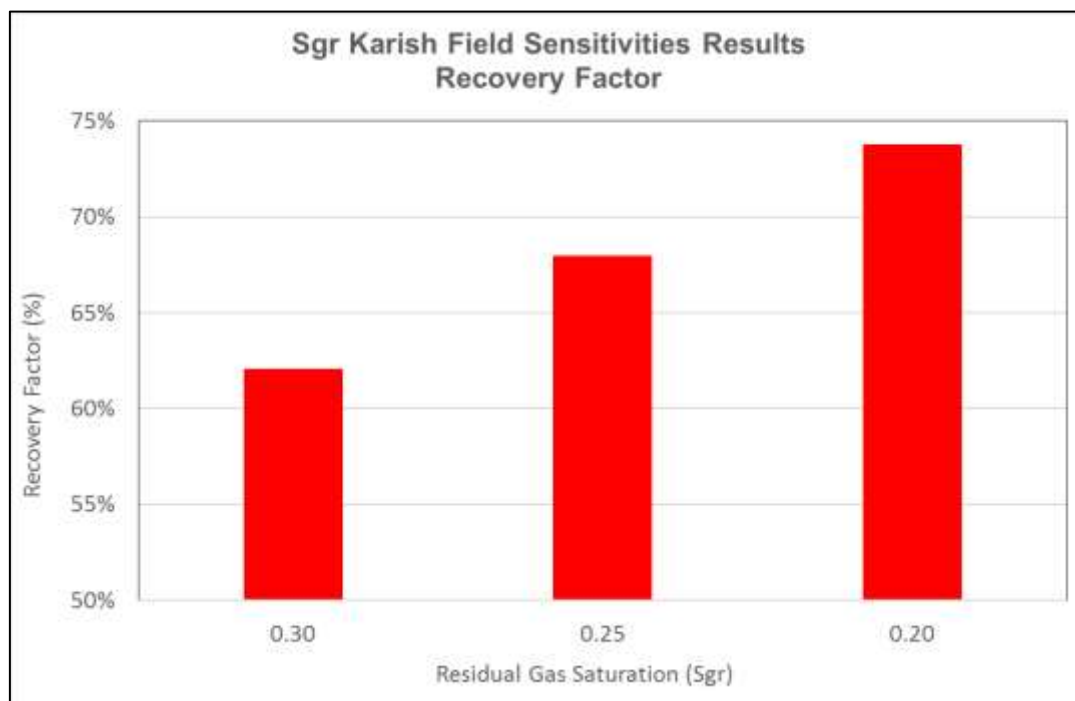


Figure 6-45 Sgr parameter sensitivity result

Figure 6-46 presents a comparison plot of the total gas production obtained in each Sgr cases generated.

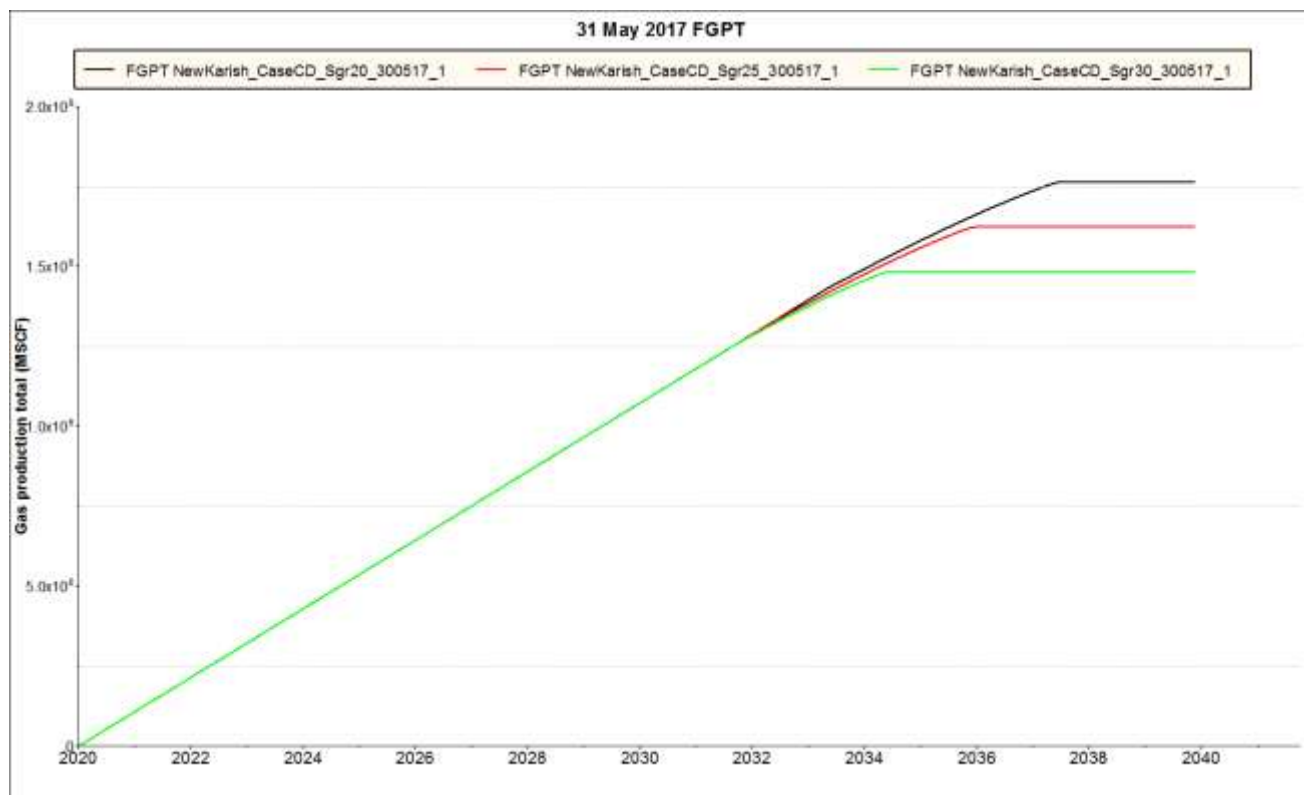


Figure 6-46 Total gas production comparison plot

The reservoir behaviour pressure obtained at the end of the simulation at 01 Jan 2039 when the Sgr was assumed 0.20 is shown in the Figure 6-47 and the pressure is found around 6750-6800 psia in the main Karish region. Figure 6-48 displays the final reservoir pressure for the case when the Sgr is 0.30 and the ranges are between 7250-6750 psi.

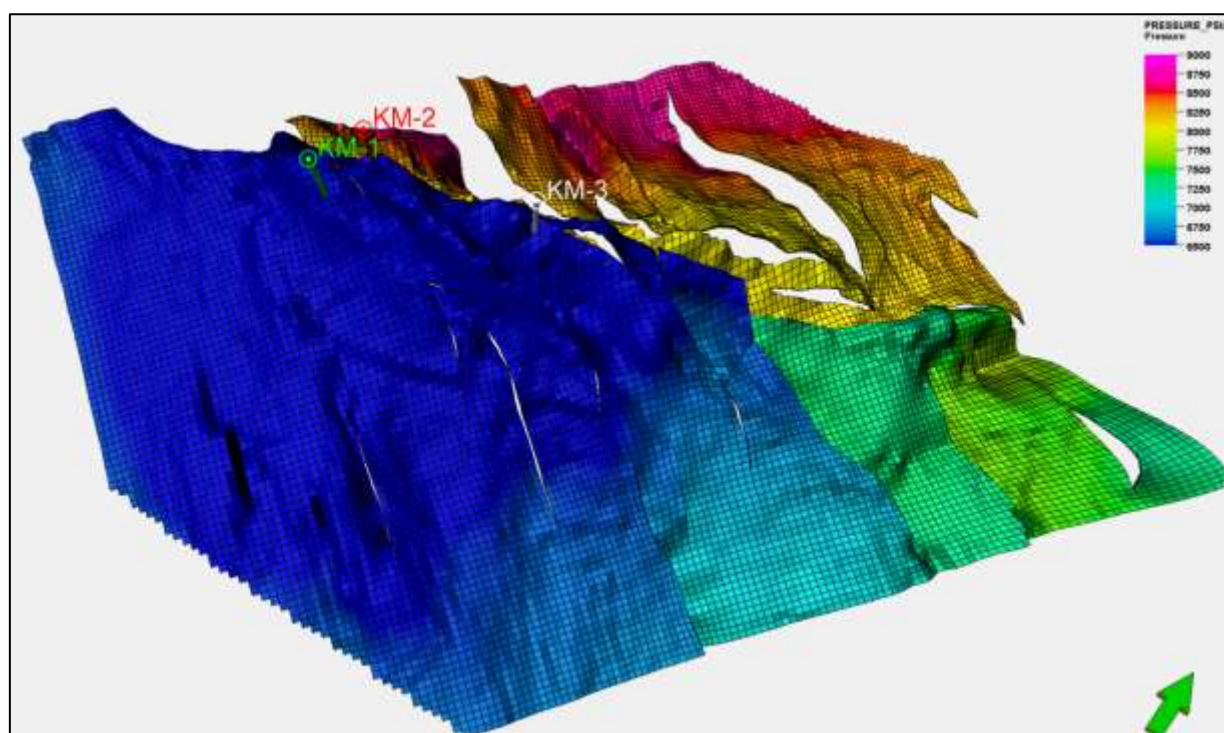


Figure 6-47 Final reservoir pressure map on layer D (top) at 01 Jan 2039 for Sgr=0.20

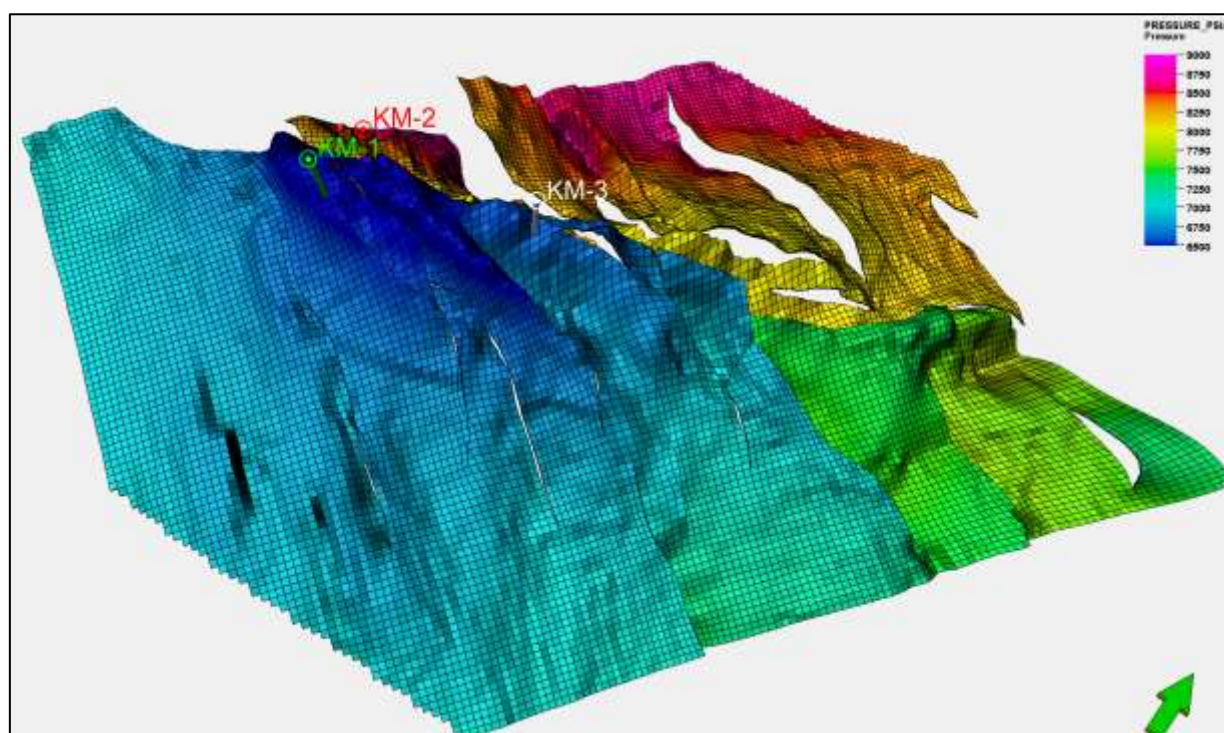


Figure 6-48 Final reservoir pressure map on layer D (top) at 01 Jan 2039 for Sgr=0.30

The Karish main results obtained for the sensitivity cases (Sgr=0.20 and =0.30) carried out are shown below.

Table 6-16: Upside Case Karish main recoverable gas volumes results by segment for layer C and D

Gas Recoverable volume (Bscf)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	641	396	464	1501
D sand	64	108	92	264
Total Field (C&D)	1765			

Table 6-17: Upside case Karish main gas recovery factor results by segment for layer C and D

Gas Recovery Factors (%)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	76.8%	71.4%	72.0%	73.8%
D sand	73.0%	72.8%	74.1%	73.3%

Table 6-18: Downside case Karish main recoverable gas volumes results by segment for layer C and D

Gas Recoverable volume (Bscf)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	539	334	391	1264
D sand	53	91	76	220
Total Field (C&D)	1485			

Table 6-19: Downside case Karish main gas recovery factor results by segment for layer C and D

Gas Recovery Factors (%)				
Layer	Segment 1	Segment 2	Segment 3	TOTAL LAYER
C sand	64.8%	60.3%	60.6%	62.2%
D sand	60.7%	61.6%	61.3%	61.3%

6.1.9.3 B reservoir scenarios

In the Karish Main modelling work described in the above sections, the B sand reservoirs were deactivated. This ensured the modelled wells produced only from the C and D units.

As there is: 1) no main sealing fault mapped between the B and C reservoirs, 2) good evidence that the minor shales have a degree of permeability and 3) in any case the non-sealing minor faults in the Karish Main field are juxtaposed across the B and C reservoir, in reality there will be a degree of depletion in the B sands when the C/D sands are produced. Gas on the flanks of the structure, below the C sand OHGP should be partially drained. Gas in the B reservoir-crest above the C sand OHGP will not. Two additional investigations were therefore undertaken to examine B sand production and recovery, namely:

- By “switching on” the B sand reservoir unit whilst draining the C/D sand it was possible to determine the fraction, if any, of the B sand GIIP that is produced from the C/D sand completions,
- By modelling the recompletion of the C/D wells in the B sand once the C/D sands were watered out, it was possible to calculate an overall recovery for the B reservoirs from these 3 drainage points (this final phase would also enable gas in the very crest of the C reservoir, up dip of the three wells an opportunity to migrate into the B reservoir and hence be produced).

Additional work will be undertaken in the next design phase to determine whether additional wells in the B sand designed to access unswept areas could add further reserves and value. These relatively minor optimisation studies were not considered critical for defining an FDP Reference case production scenario. Similarly work to determine whether the location of the wells can be optimised further to maximise total drainage from the B, C and D units in the initial development phase will be undertaken (the current well locations were designed to optimise drainage from the C/D alone). It is not expected that this will have a significant impact on the results.

6.1.9.3.1 Results of the B reservoir production studies

The results of the described B reservoir additional cases are shown below in Table 6-20. By activating the B reservoir cells in the model whilst producing from the C/D unit a significant increase in production was observed before water breakthrough occurred. 53.2% of the B reservoir GIIP was produced. Recovery in the C and D zones remained relatively constant. Co-production of the B sands extends the plateau of the Karish field and hence delays the point where Tanin would be developed. However it also means that the period over which the liquid reserves in the C/D sands is produced is extended (PVT data on the B sands is limited but available fluid samples indicate it is leaner and Energean has modelled it with a CGR similar to the Tanin fluids). Clearly the performance of the B sands is therefore a relatively significant field development sensitivity. Table 6-20 also illustrates that the proposed workovers add a further 120 Bcf of production, partly from the B sands and

partly from the C sands as was postulated. Although this volume is not large in the overall development scheme it is actually greater than the gas associated with Tanin block B and can be recovered at a lower CAPEX spend. As described later in this section the development of Tanin B was specifically investigated to determine whether it provided incremental value. As this was demonstrated to be the case – indeed its economics were surprisingly good – then the workover of the Karish Main wells would be even better and are hence included in the FDP Reference case production scenarios. From the end-simulation pressure map it can be observed that there is likely potential to further increase B sand recovery by adding an additional well in the crest of the field subsequent to the workovers of instead of. Again this fine tuning of the Reference case will be addressed in the next stage. Any activity to increase B sand Rf. to the same level as the C sand (i.e. by about 9%) would add 75 Bcf or > 2 BCM. Again this increase would likely justify an additional well.

Table 6-20: Recovery from B reservoirs – two cases

Cases	Gas Production Total [Bscf]	B Layer	C Layer	D Layer	Total Field (B&C&D)
		RF (%)	RF (%)	RF (%)	RF (%)
B/C/D co-production via OHGP (with production from B reservoirs during production of C/D reservoirs)	2071	53.2	68.1	67.0	62.8
Subsequent B layer production (additional production following re-completion with CHGP over the B units)	2191	61.4	70.5	67.2	66.4

The reservoir pressures obtained in the B/C/D co-production case at the beginning and end of the simulation at the top of layer B are shown in Figure 6-49 and Figure 6-50.

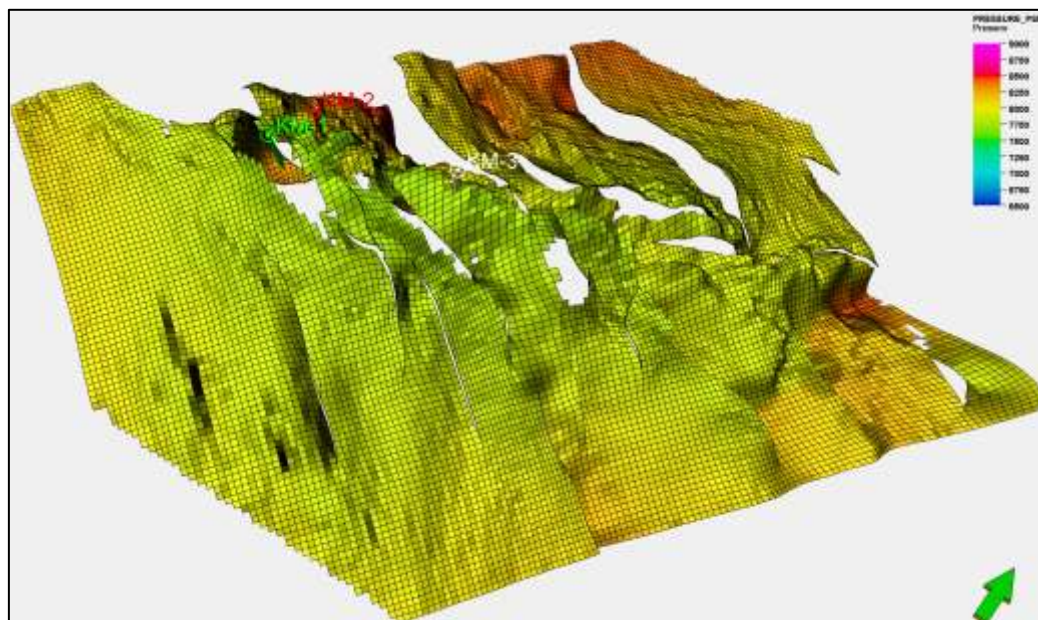


Figure 6-49 Initial reservoir pressure map on layer B (top) at 01 Jan 2020 for Sgr=0.25

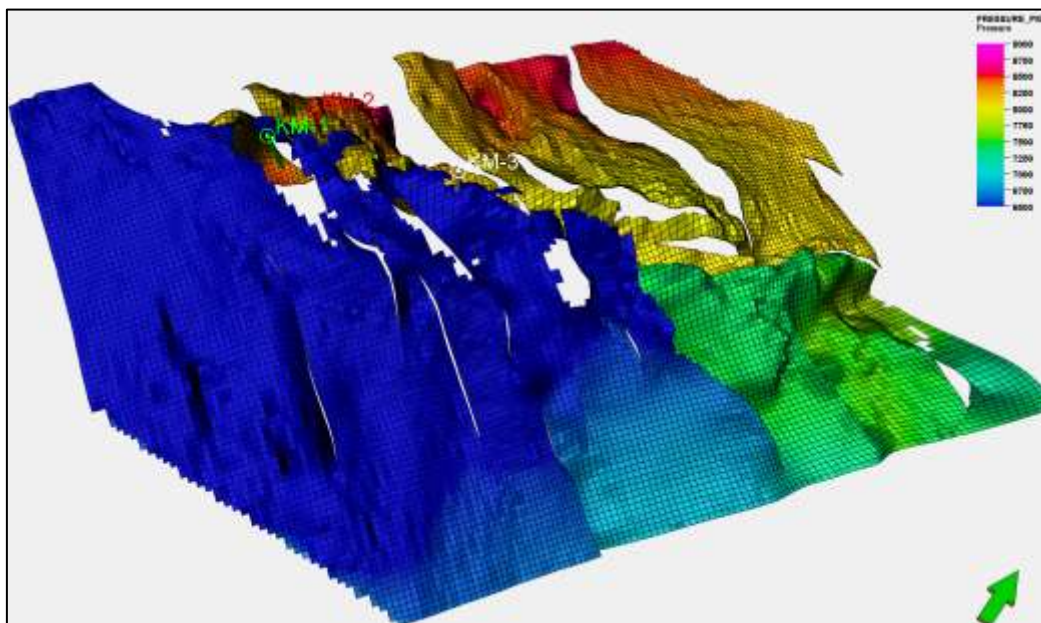


Figure 6-50 Final reservoir pressure map on layer B (top) at 01 Jan 2039 for Sgr=0.25

Table 6-21 to Table 6-23 display the results obtained for the case B&C&D active layers.

Table 6-21: B&C&D case Karish main GIIP results by layer

Layer	GIIP (Bscf)
B sand	837
C sand	2033
D sand	360
Total Field (B&C&D)	3230

Table 6-22: B&C&D case Karish main recoverable gas volumes results by layer

Layer	Gas Recoverable volume (Bscf)
B sand	445
C sand	1385
D sand	241
Total Field (B&C&D)	2071

Table 6-23: B&C&D case Karish main gas recovery factor results by layer

Layer	Gas Recovery Factors (%)
B sand	53.2%
C sand	68.1%
D sand	67.0%

6.1.10 Tanin Simulation Model

Results from the Tanin Reservoir Engineering simulation model have been used to estimate recovery factors from the three discovered blocks by varying the number and position of the wells to be drilled. Information from the discovery well, Tanin-1 (well logs, fluids sample analysis) and the available geological model were used to construct the simulation model in Eclipse. Well numbers were increased from 2 to a maximum of 6. Well locations were adjusted in an attempt to maximise total recovery factor (rather than recovery factor per block) and to maximise the time before formation water production commenced. Vertical wells were modelled for blocks A and B. For block C, due to the flatness of the structure, with little distance from the underlying aquifer, the potential benefit of using horizontal wells was investigated. Best-technical Case work assumed and Sgr of 0.25. Sensitivities with Sgr between 0.2 and 0.3 were run and are discussed.

6.1.10.1 Initialisation

During the initialisation stage the initial gas in-place (GIIP) was calculated by Eclipse for layers A&B. When compared with the static model, the difference was around 1% (layer A) and 3% (layer B). Table 6-24 shows the GIIPs of the Petrel static model and Eclipse dynamic model.

Table 6-24: Simulation model initialisation

	PETREL STATIC MODEL	ECLIPSE MODEL
Layers	ORIGINALLY IN PLACE GIIP[Bscf]	ORIGINALLY IN PLACE GIIP[Bscf]
Tanin	Tanin	Tanin
A	1461	1469
B	232	238
Total A and B	1693	1708

Figure 6-51 shows the initial Tanin reservoir pressure grid distribution obtained during the initialisation. The initial average reservoir pressure in Tanin field was calculated at 8,700 psia at the top of layer A.

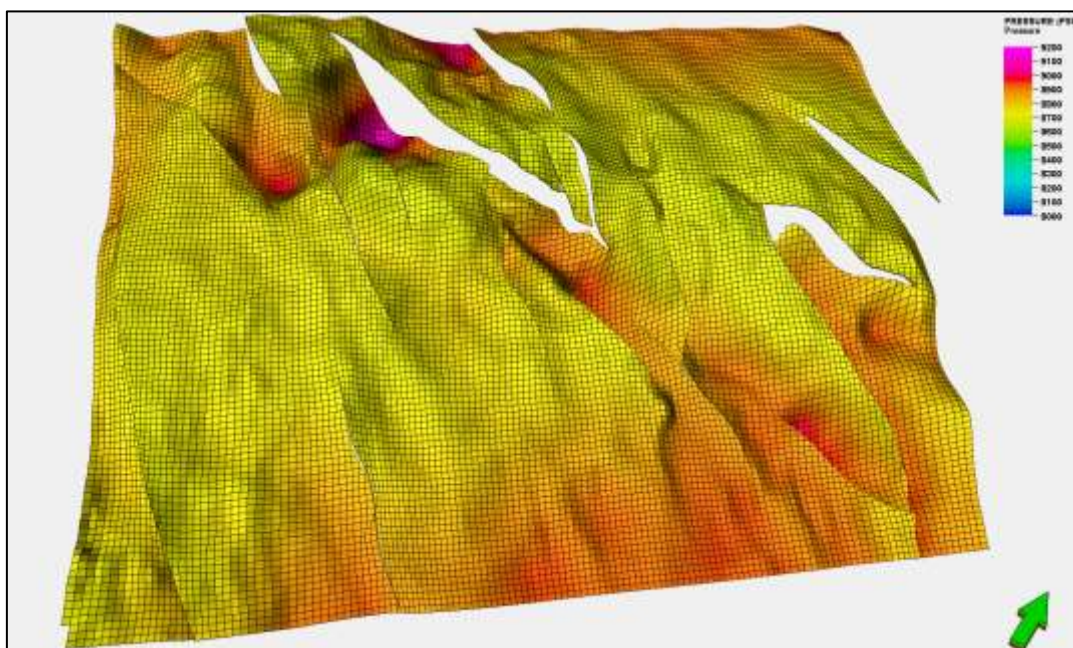


Figure 6-51 Initial reservoir pressures Tanin

The model was divided into three areal regions representing Block A, Block B and Block C. Figure 6-52Figure 6-39 indicates the location of Block A (green colour), Block B (cyan colour), Block C (purple colour) and the aquifer (blue colour). The GIIP per block is illustrated in the below table.

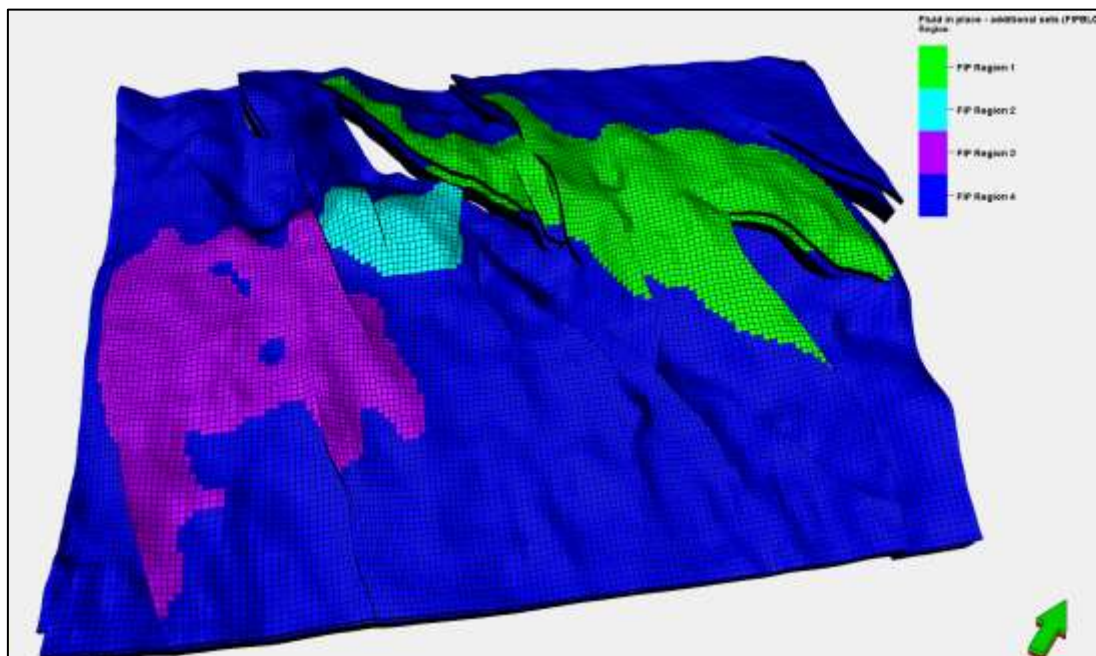


Figure 6-52 Tanin reservoir model blocks

Table 6-25 Tanin field - GIIP by block in reservoir model

TANIN ECLIPSE MODEL	
Block	ORIGINALLY IN PLACE GIIP[Bscf]
A	1019
B	173
C	516
Total A, B and C	1708

6.1.11 Best-technical Case Simulation Run

Following an analysis of various well development scenarios of between 2 and 6 wells, the 6 well case – which provided the maximum recovery – was selected as the FDP Best-technical case. It is possible that further planned work may show that the economic optimum is actually 5 wells (i.e. 1 well in the C block rather than 2). However it was felt prudent at this point to use the case with the largest amount of wells and hence the greatest CAPEX. Well placement, particularly in blocks A and block C will be further optimised in an attempt to further increase overall recovery in due course.

The main input parameters for the Tanin field Best-technical case were therefore:

- Field simulated as a stand-alone development; Tanin production starts at 292 mmscf/day (in reality Tanin production will be developed prior to Karish coming off plateau and will be phased in as required to maintain the plateau – sensitivities indicated that a gradual ramp-up had no impact on overall recovery and hence was ignored),
- All minor internal faults in Tanin field are assumed as non-sealing faults (based on fault-seal analysis),

- Rock compressibility of 7.5-05 1/psi was selected as typical for this type of unconsolidated formations assuming more unconsolidated rock than Karish. (See reference number [1] – (Newman 1973)),
- Analytical Fetkovich aquifer is connected to only the outer edges of A&B layers,
- No downtime was assumed. All wells are assumed to be available from the start of production on 1st January 2036 and the simulation was run for 15 years,
- A maximum flooding surface is considered between A sand and B sand, it is expected that both layers are in vertical communication through the faults,
- Grid block properties such as porosity, permeability and net gross ratio have been defined for the intra-reservoir shales to allow vertical transmissibility within both layers A and B (as per Karish),
- Aquifer has been sized to match pressure drop of around 200 psia at 6.25% of recovery factor based on Tamar analogue field as is shown in Figure 6-43,
- Residual gas saturation (gas trap) of 0.25,
- The optimised Best-technical case consists of 6 vertical wells drilled in two different phases. The first phase corresponds to three vertical wells in Block A (TA-1, TA-2 and TA-3) at the beginning of the field life and the second drilling phase was assumed to start when the plateau started to drop, then two wells from Block C (TC-1 and TC-2) and one well from Block B (TB-1) are brought on line one by one scheduled every 6 months. All vertical wells are simulated with perforations at the top of the structure in Layer A,
- Well rates are controlled by vertical lift tables, with a flowing THP limit of 3481 psia,
- Field water gas ratio limit of 10 stb/mmscf.

Figure 6-54 to Figure 6-57 present maps with the results of gas saturation from the beginning of the simulation 1st January 2036 to 1st January 2051 for sands A and B and final reservoir pressure at the top of layer A.

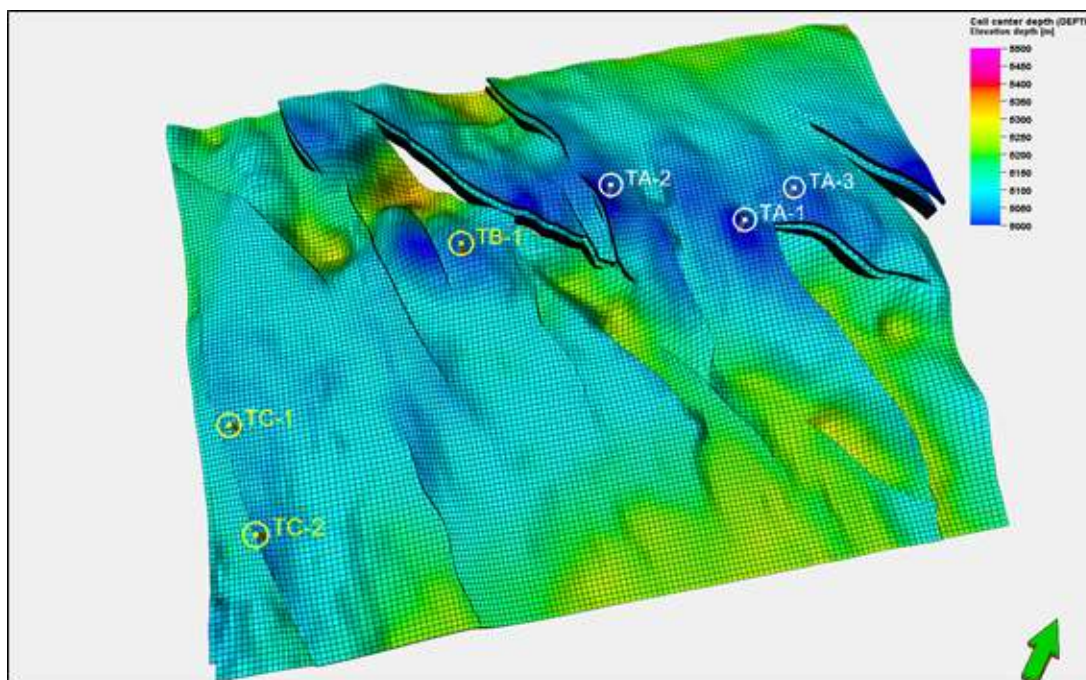


Figure 6-53 Tanin Reference-case well locations

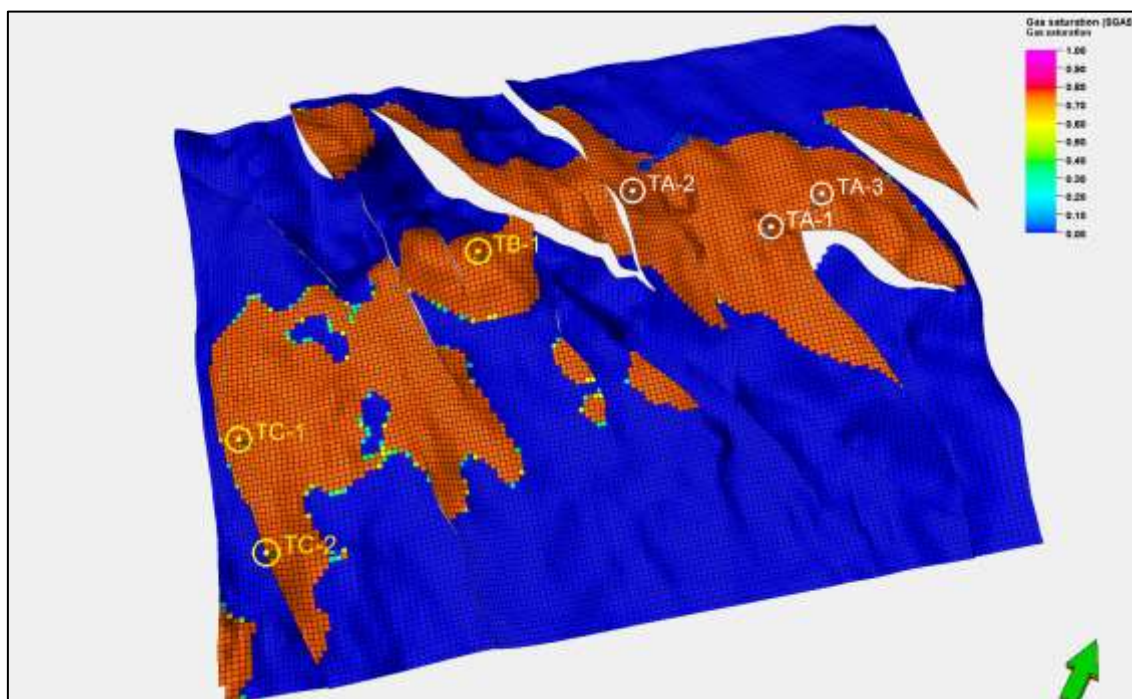


Figure 6-54 Initial gas saturation map on layer A (top) at 01 Jan 2036

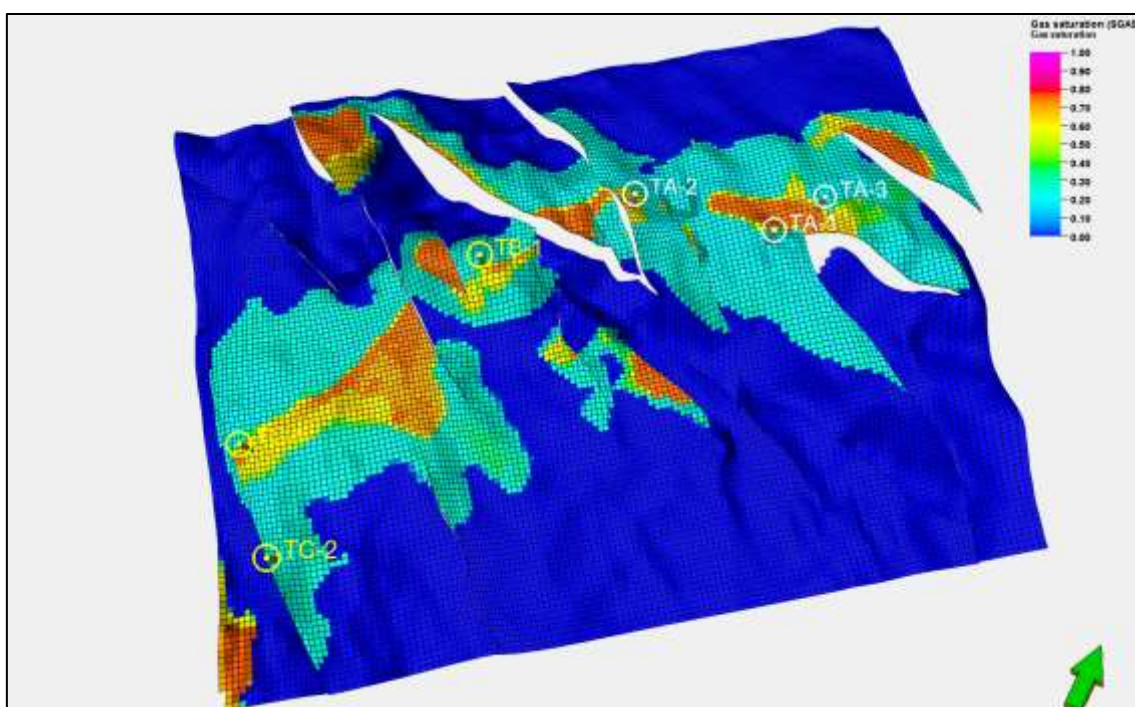


Figure 6-55 Final gas saturation map on layer A (top) at 01 Jan 2051

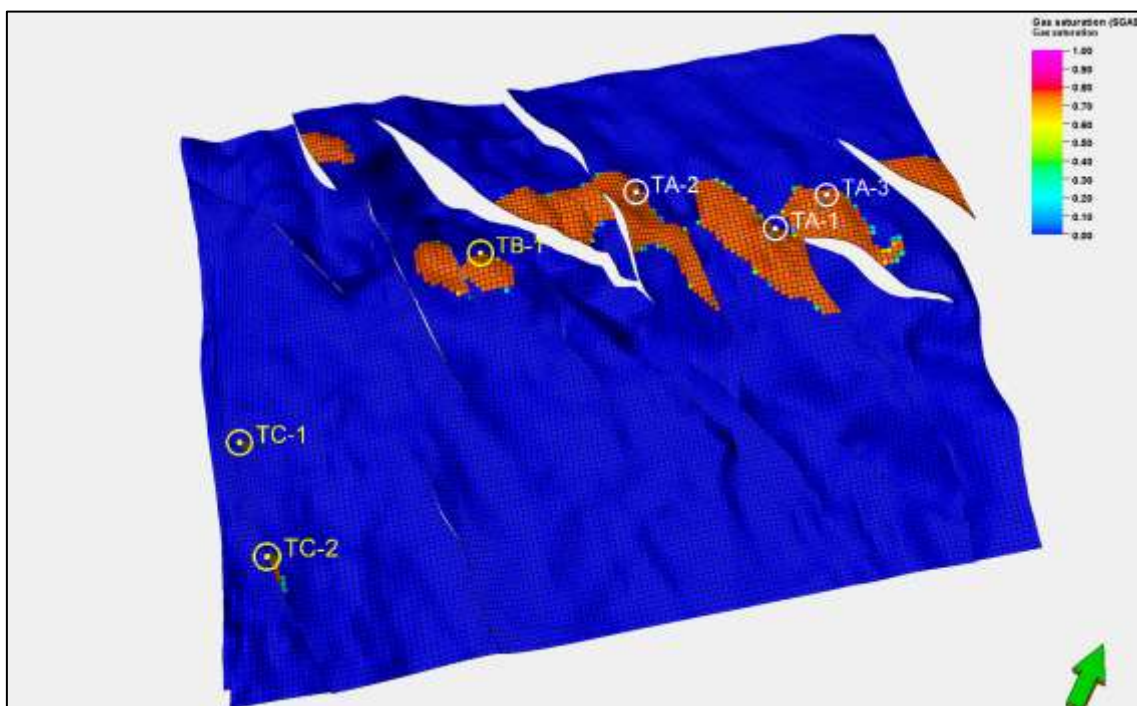


Figure 6-56 Initial gas saturation map on layer B (top) at 01 Jan 2036

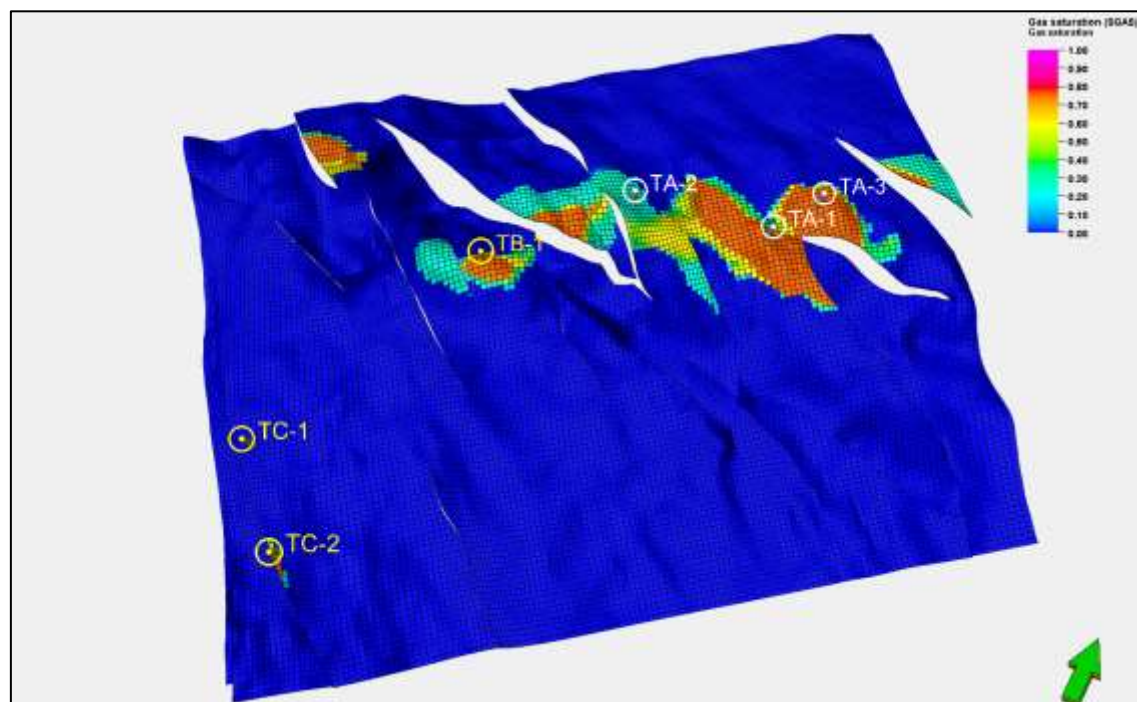


Figure 6-57 Final gas saturation map on layer B (top) at 01 Jan 2051

The reservoir pressure obtained at the final time step of the Best-technical case forecast is presented in Figure 6-58.

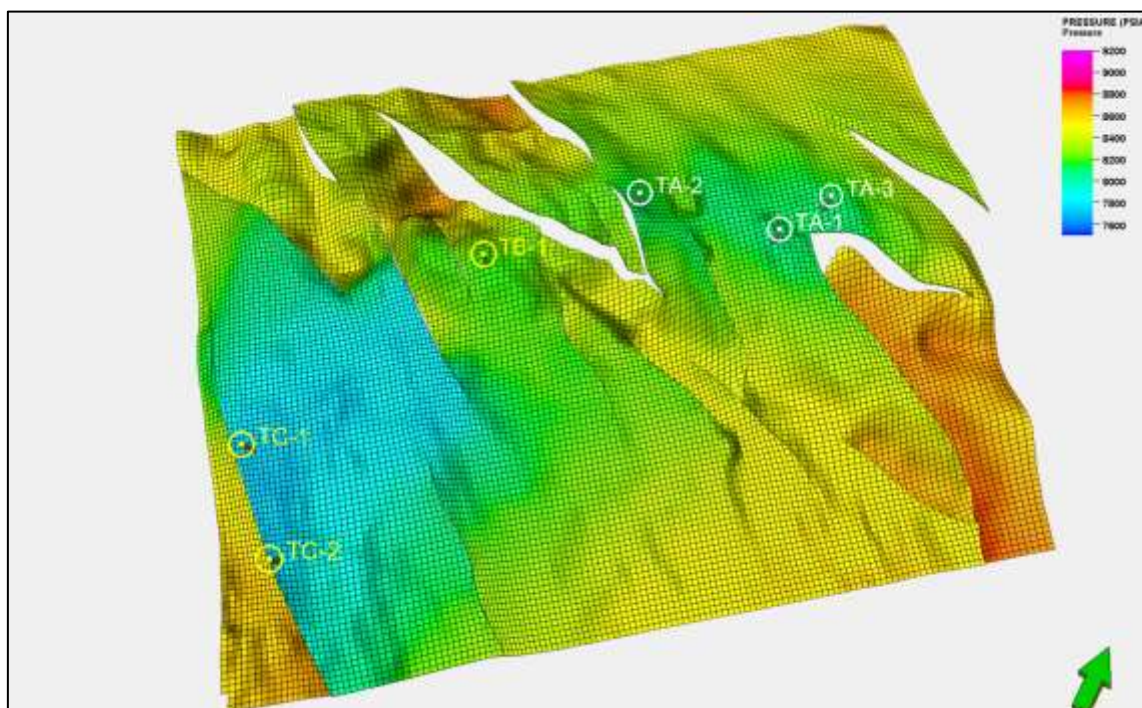


Figure 6-58 Final reservoir pressure map on layer A (top) at 01 Jan 2051

The resources estimated after 12 years of production for the optimised Best-technical case are presented in Table 6-26 to Table 6-28. The results are by block. The forecasted production and reservoir pressure plots are shown in Figure 6-59 to Figure 6-62.

Table 6-26 Tanin Best-technical case GIIP by block

GIIP (Bscf)			
Layer	Block A	Block B	Block C
A&B	1019	173	516
Total Field	1708		

Table 6-27 Tanin Best-technical case recoverable gas by block

Gas Recoverable volume (Bscf)			
Layer	Block A	Block B	Block C
A&B	657	103	303
Total Field	1063		

Table 6-28 Tanin Best-technical case recovery factors by block

Gas Recovery Factors (%)			
Layer	Block A	Block B	Block C
A&B	64.5%	59.6%	58.8%
Total Field	62.3%		

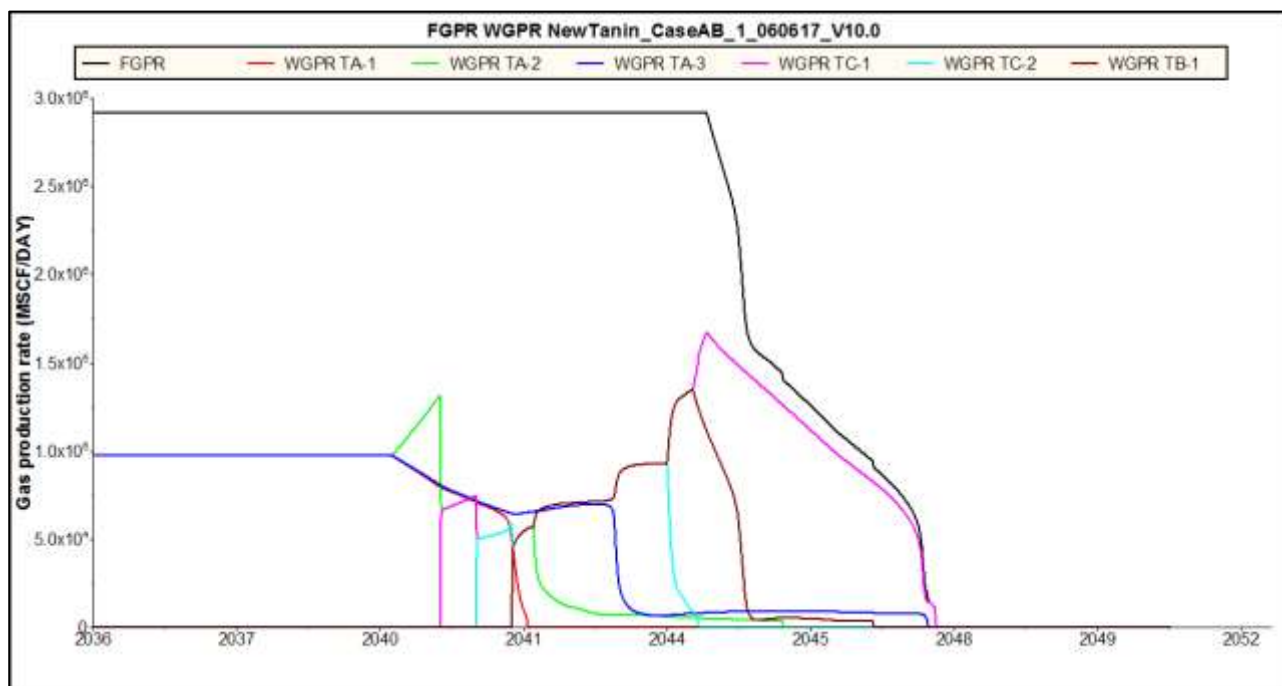


Figure 6-59 Best-technical case Tanin field and well gas rate forecast

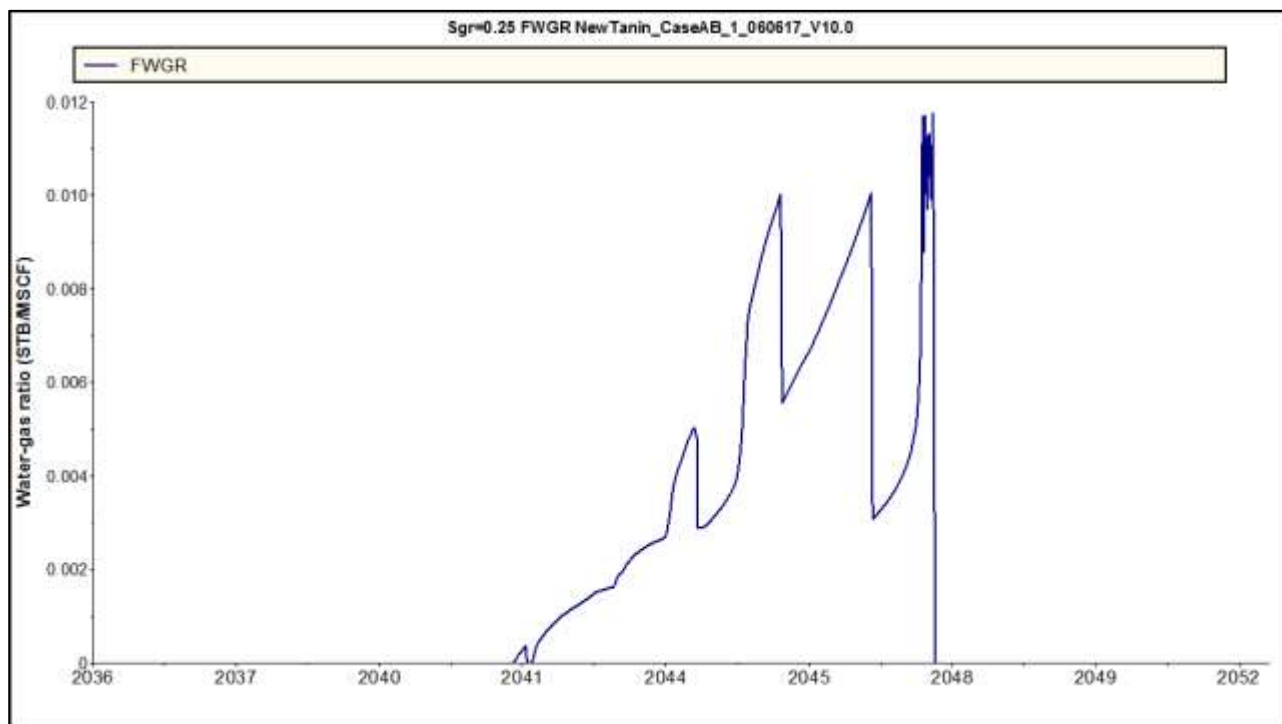


Figure 6-60 Best-technical case Tanin field WGR forecast

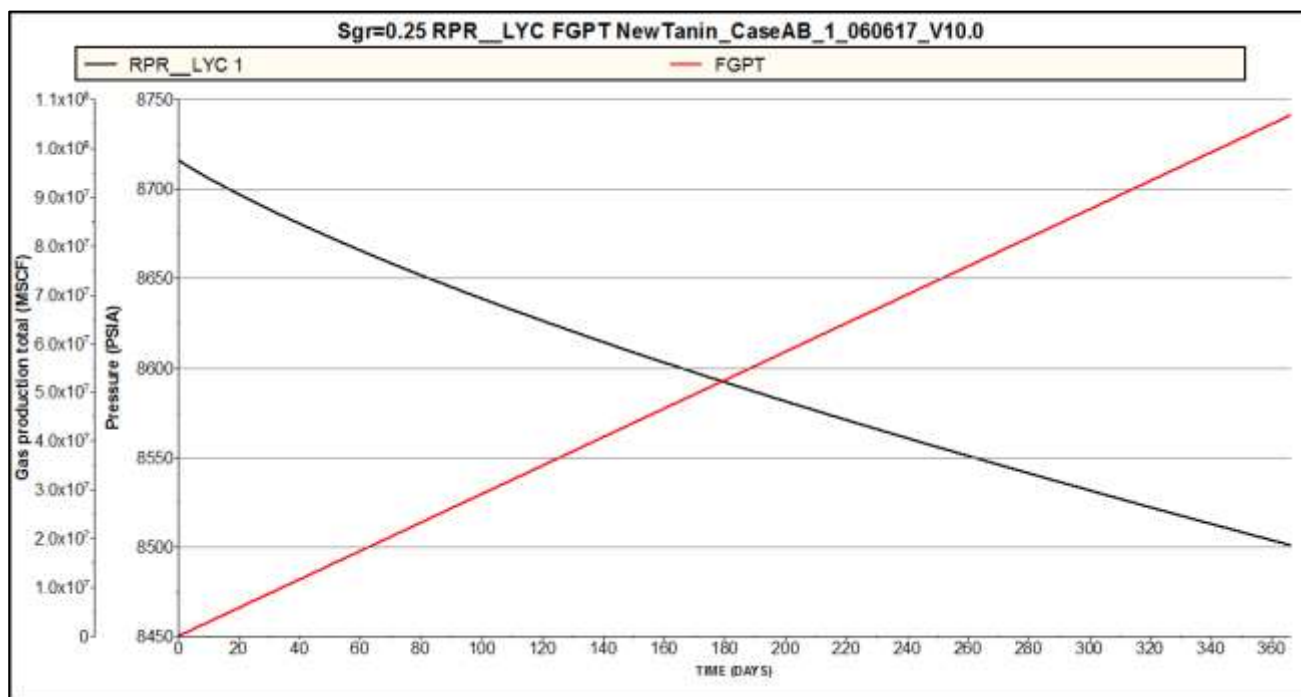


Figure 6-61 Best-technical case Tanin pressure drop forecast at 6.25% of recovery factor

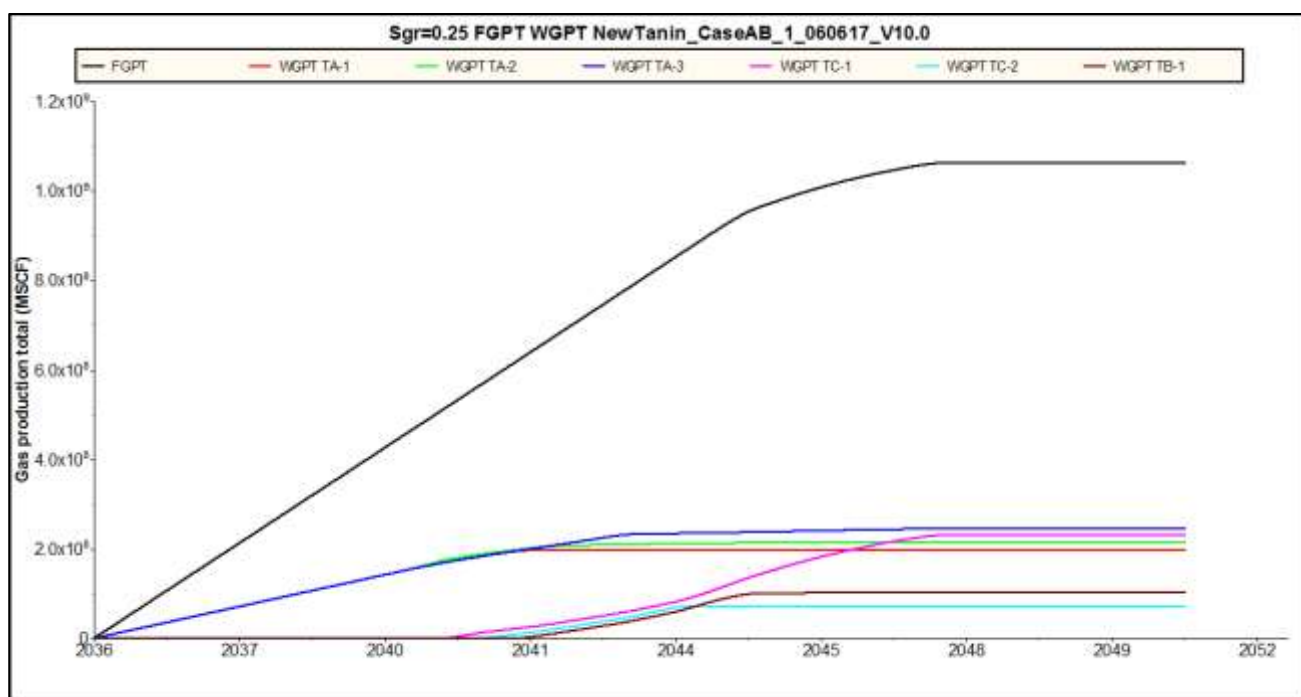


Figure 6-62 Base case Tanin total gas production by field and by well forecast

6.1.11.1 Sensitivities

A number of sensitivity runs were undertaken for Karish simulation model as described above. Parameters such as initial water saturation, residual gas saturation, vertical to horizontal permeability ratio, the water to gas ratio and Fetkovich aquifer parameters were tested to the upper and lower side each. It was concluded that residual gas saturation is the parameter with the most impact on gas recovery.

Therefore for Tanin this was the sensitivity analysis undertaken. Sgr was varied between 0.20 and 0.30.

Table 6-29 provides the results of the sensitivity analysis of Sgr.

Table 6-29 Tanin sensitivity analysis

Parameter	Ranges	Case	Gas Production Total [Bscf]	Field Plateau duration (years)	Block A	Block B	Block C	Total Field (A&B Sands)
					RF (%)	RF (%)	RF (%)	RF (%)
Sgr	0.30	Downside	973	7.7	59.0%	54.4%	53.9%	57.0%
	0.25	BaseCase	1063	8.5	64.5%	59.6%	58.8%	62.3%
	0.20	Upside	1153	9.2	69.8%	64.3%	64.1%	67.5%

6.2 Production Forecasting and well planning

Detailed production forecasts were produced using the reservoir simulator described in Section 6.1. A range of well positions were studied to ascertain the optimal number of wells per field and the resulting recovery factors per segment and reservoir layer taking into account possible movements between these segments and layers via the shales and faults that segregate them. The results of these detailed simulation models were then used to calibrate a simplified model (in the programme MBAL) that was in turn used within an Integrated Production System Modelling simulation. This model provided a link between the simplified reservoir model, a detailed well completion model (Prosper) and a hydraulic simulator (GAP) that allowed the system between the wells and FPSO to be modelled and less overall pressures and temperatures to be determined. GAP allows the impact of changes in the FPSO operating pressure to be determined.

This integrated modelling approach is paramount to accurately estimating the overall subsea system deliverability and the operating conditions the system will experience during the field life. Figure 6-63 below shows at a high level the construction of such an IPSM model.

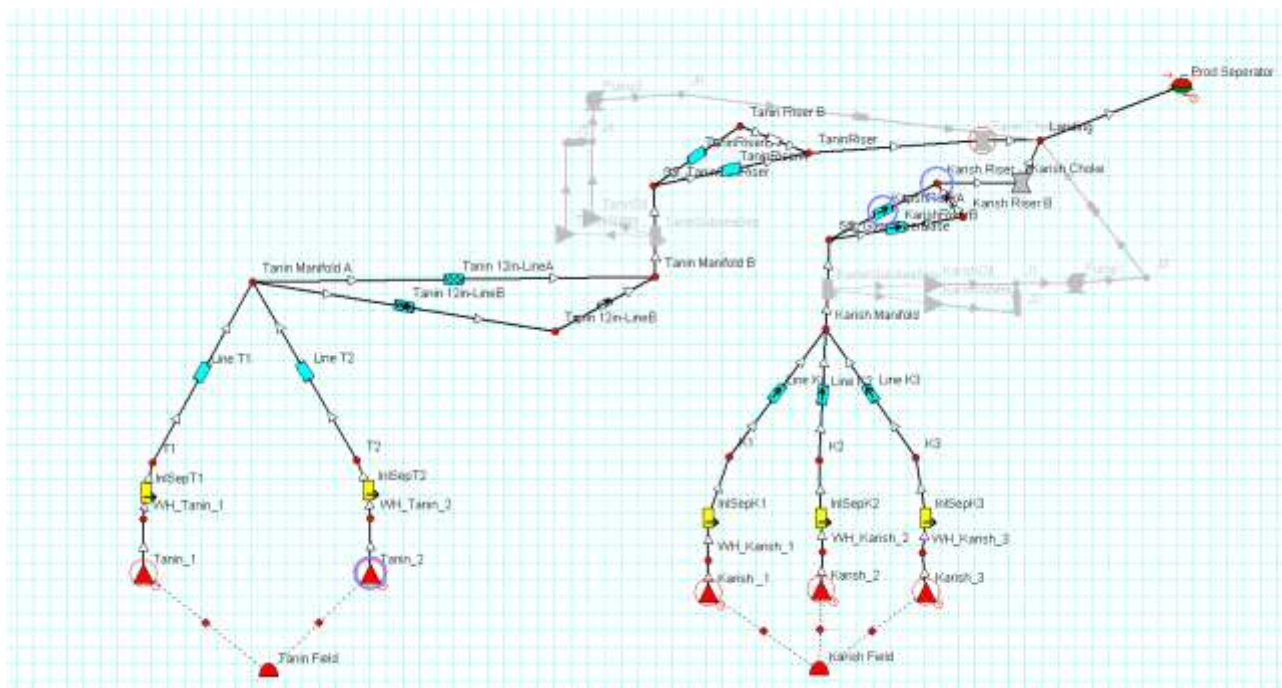


Figure 6-63 Karish and Tanin IPSM snapshot

This IPSM model was used to ensure that at all times the proposed number of wells could deliver sufficient gas to satisfy a particular demand profile when 1 well was assumed not available for whatever reason. Clearly when designing a system to satisfy gas sales contracts it is important that there is redundancy in the number of wells available.

The production profile below demonstrates, for one particular scenario, how well potential could be maintained such that N-1 wells are capable of delivering the maximum production rate (400 mmscf/day) at any time. This scenario assumes 3 Karish Main wells with all B reservoir production post the planned workovers and just 2 wells drilled to drain the Tanin A block, but serves to demonstrate the logic applied to all scenarios investigated.

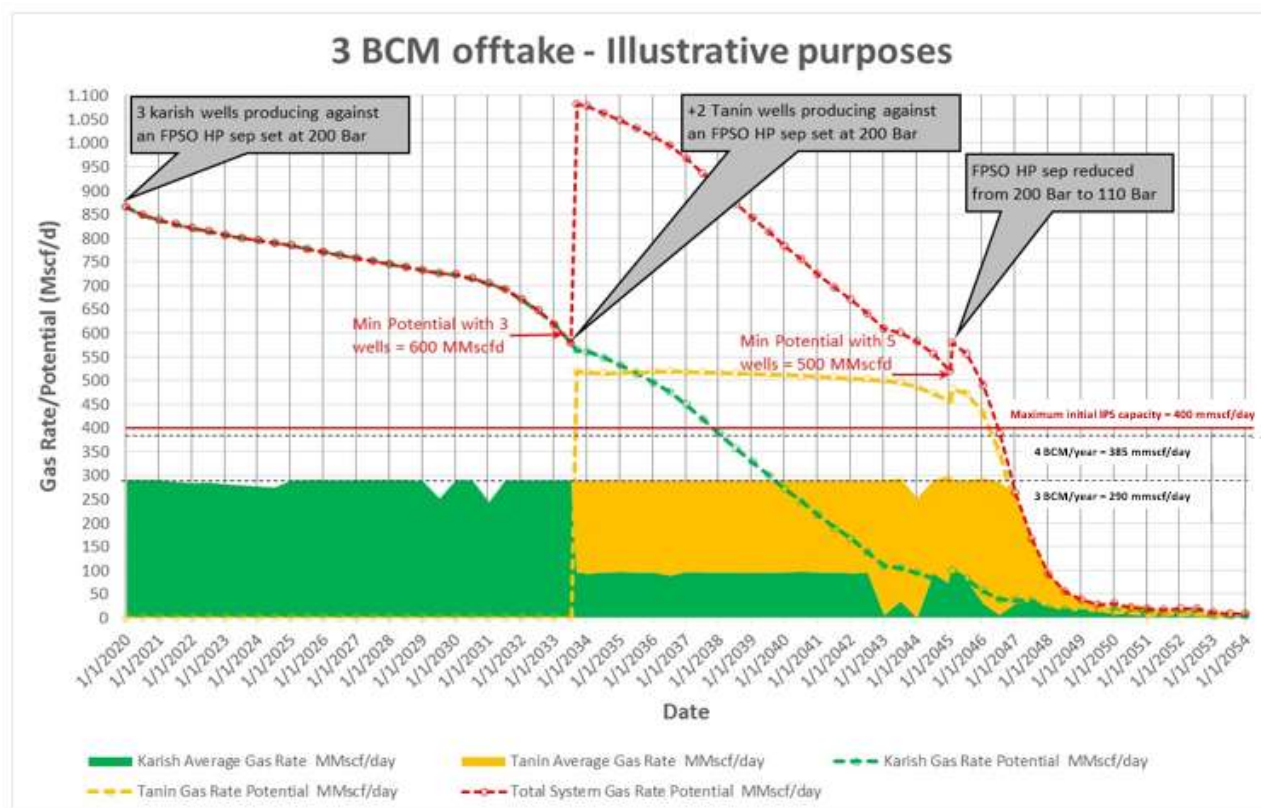


Figure 6-64 IPSP 3BCM/year production profile- Illustrative

For 3BCM sales gas per annum, the average daily flow of dry-gas into the pipeline to Dor will be 290 mmscf/day. However taking into account downtime (planned and unplanned) as well as the required variability in gas supply quantities it is considered prudent to ensure that the wells have the capacity to fill the design capacity of the FPSO (400 mmscf/day) at all times on an N-1 basis.

The dotted lines in the above figure represent the gas rate potential of the subsea production system, while the blocks represent the annual sales, here shown at 3 BCM/year. The simulation is run initially with 3 Karish Main wells with an HP separator set at 200bar on the FPSO. It is assumed that once Tanin is brought on line, it will supply 2/3rd of the gas whilst Karish Main will generate 1BCM/year offtake (from the recompleted B wells).

Once the Karish Main subsea system potential falls below 600MMscfd, each individual well has a 200 mmscf/day max deliverability. Would one well be lost (completion problem, workover requirement, water breakthrough), the total system deliverability would fall under 400 mmscf/day which is the point where Tanin or other wells needs to be available.

Similarly once the system has 5 wells available, the minimum total system deliverability needs to be 500 mmscf/day, meaning each individual well will have a minimum deliverability of 100 mmscf/day, allowing Energean to meet its MDQ target of 400 mmscf/day assuming one well is lost.

The following observations can be made when analysing the above figure:

- Initial subsea production system deliverability is 900 mmscf/day, which means each well will be able to deliver initially 300 mmscf/day, taking into account the frictional losses and hydrostatic back pressure on the wells
- With 3 Karish Main wells online it takes approximately 13 years for the deliverability to fall below 600 mmscf/day (in this scenario), by which time additional wells would be needed to maintain a robust supply position to honor 3BCM/year offtake agreements
- Bringing on 2 Tanin wells, adds 520 mmscf/day to the overall subsea system deliverability, which means each well will be able to deliver initially 260 mmscf/day, taking into account the frictional losses and hydrostatic back pressure on the wells, which are greater for Tanin than they are for Karish,

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- By 2045, the overall subsea system deliverability falls below 500 mmscf/day requiring to add more well or reduce the HP separator landing pressure, which is done with limited effect as the remaining gas in place is very small,
- It can be noted that in this simulation the deliverability decline of the Tanin system is very flat vs Karish one, indicating that the aquifer support is stronger in Tanin than in Karish.

6.3 FDP Production Forecasts

As outlined above, numerous production scenarios were investigated whilst generating this FDP. As gas sales contracts are currently being negotiated the total volume of gas to be produced at start-up had to be treated as a variable. Similarly daily and annual swing requirements and the potential for market growth had to be assumed. This uncertainty, inherent in any gas development at the end of concept engineering, required Energean to design a system that had the flexibility to cope with these commercial uncertainties in addition to the technical uncertainties outlined previously (well reliability, aquifer strength).

Whilst faced with these uncertainties it was key for Energean to define a scenario that would be used in conjunction with the “best technical case” gas-in-place volumes outlined in Section 5, to allow an economic evaluation to be undertaken and the commercial viability to be determined. The robustness of this Reference-case development could then be tested taking into account down-side sensitivities regarding gas in place, recovery factor, sales volumes, availability, cost, schedule and sales price over the currently assessed margin of uncertainty.

The following represents the key characteristics of the defined Reference-case:

- Development of the Karish Main field with 3 new-drill wells,
- Production start-up end Q1 2020,
- All initial wells completed with OHGPs in the top C reservoir,
- Gas fill assumed in the Karish Main D reservoir (POS of Karish Main D gas volumes calculated as > 90%),
- Transmissibility of Karish Main faults as per the shale-gouge ration analysis (i.e. minor faults pass and main bounding faults seal),
- Potential production from the Karish Main B sands allowed via transmission through the modelled fault network and around shale baffles,
- Average production offtake from the Karish Main wells managed to be on average proportional to the GIIP in the three defined reservoir segments,
- Tanin A block developed so that gas would be available 2 years prior to the predicted production decline from the Karish Main wells,
- Tanin A block developed by 3 new-drilled wells,
- The potential of Karish North and other upside exploration prospects considered more attractive than Tanin block A ignored,
- Karish Main A sand potential ignored,
- Karish Main wells workover immediately following the point where water production exceeds 5 bbls/mmscf. Wells recompleted with CHGPs in the B reservoir,
- Karish Main B production maintained at 100 mmscf/day until the B sands water out,
- Tanin block C developed with 2 wells prior to decline in production from Tanin block A wells,
- Tanin block B developed with 1 well 2 years after Tanin Block C development,
- Average gas production post shrinkage and fuel use (2.5% in total) constrained at 3 BCM/year,
- Total well production potential maintained at 400 mmscf/day (post 2.5% losses) with N-1 wells,
- Liquid production based on P50 CGRs determined from PVT analysis.

Mid case recovery factors as determined from the Reservoir simulation modelling study were honoured. Due to the strong aquifer assumed – based on actual historical data made available from the Tamar field – the degree of pressure drop experienced during production is small. Wells do not loose potential gradually as reservoir pressure declines resulting in a short plateau and long tail, but suddenly, once water breaks through. In general the reservoir simulation work undertaken demonstrated that due to the good sand rock properties and low level of reservoir heterogeneity wells water out rapidly once water cuts begin to increase and the proportion of EUR achieved prior to the arrival of water is in the order of 95%. This leads to the prediction of

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production forecasts characterized by very high initial individual well potentials, extended periods of relatively steady production (with declining well potentials), followed by short sharp declines. Prior to this decline a new “virgin pressure” accumulation needs to be available to maintain the overall Lease plateau.

The optimal manner of phasing in a new development whilst phasing out the field experiencing a sudden decline will be studied further going forward. It is possible that by curtailing production from the declining field it might be possible to minimize the rate of water build up, increase reservoir pressures and hence increase recovery factors above the levels currently simulated. It is also possible that for the smaller accumulations it may be possible to use the fact that the FPSO can work at low inlet pressures to “out-run” the aquifer, reduce the reservoir pressures and hence again increase recovery.

Although numerous alternative scenarios have been investigated only one of these is presented in this FDP. This is the scenario described above for Karish Main where the performance of the B sands was studied. In this alternative scenario it was assumed that no gas would be produced from these thin laminated sands until after the planned work overs. As stated earlier the size and performance of these sands represents the largest subsurface uncertainty identified. By shifting the date of their development it allowed their potential impact on the economics to be identified.

6.4 Section references

REFERENCE NUMBER	REFERENCE TITLE
[1]	SPE-3835-PA. Pore-Volume Compressibility of Consolidated, Friable, and Unconsolidated Reservoir Rocks Under Hydrostatic Loading. G.H. Newman

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7 Facilities and Wells Development

This section describes the Facilities and Wells that Energean intends to construct to develop the hydrocarbon accumulations within the Karish and Tanin Leases. The first field to be developed will be Karish Main located within the Karish Lease. The assets required to develop this field will be installed and commissioned by early 2020 with the intent of introducing a second source of gas supply into the Israeli market as soon as practicable. A subsequent development of the Tanin Block A, B and C discoveries within the Tanin Lease is also included in this FDP. The timing of these supplementary phases will depend on a number of factors, particularly:

- The quantity of gas sale contracts secured by 2020 and the growth in sales subsequent to this date,
- The confirmed in-place volumes within the Karish Main C/D post drilling,
- The volume of fluid within the Karish Main B reservoir unit confirmed post appraisal of this unit during the development of the Karish Main C/D reservoirs,
- The timing of exploration activities in the Leases and the results of these activities, particularly the timing of the drilling of the Karish North prospect in the Karish Lease.

Each of these factors impacts the time the existing Tanin discoveries are developed, the facilities that will be installed at that time and hence the development cost. For the sake of this FDP the development scenario assumed holds gas sales constant at 3 Bcm/year (i.e. zero sales growth) and assumes that no additional exploration activities are executed (i.e. Tanin A/B/C Blocks are developed after Karish Main is unable to deliver 3 BCM/year to market).

However, where ever feasible Energean has designed the planned facilities to enable other yet-to-find gas volumes in the north of Israel to be tied back thus ensuring they can be efficiently and expeditiously brought into production. Facility allowances for yet-to-discover volumes are noted where applicable.

7.1 Development Concept Selection

This section explains the opportunity maturation process that Energean followed in identifying the optimal development concept for the Karish and Tanin Leases. The range of development concepts examined since work commenced late 2015 is fully outlined along with the rationale for selecting a concept based around a new-build, spread-moored, FPSO with dry-gas pipeline landing at Dor in the north of Israel.

7.1.1 Introduction

Energean uses a stage-gate process to manage its development projects. This process is illustrated in Figure 7-1, below. The Karish and Tanin development project has progressed through this process since late 2015 when the opportunity was first identified.

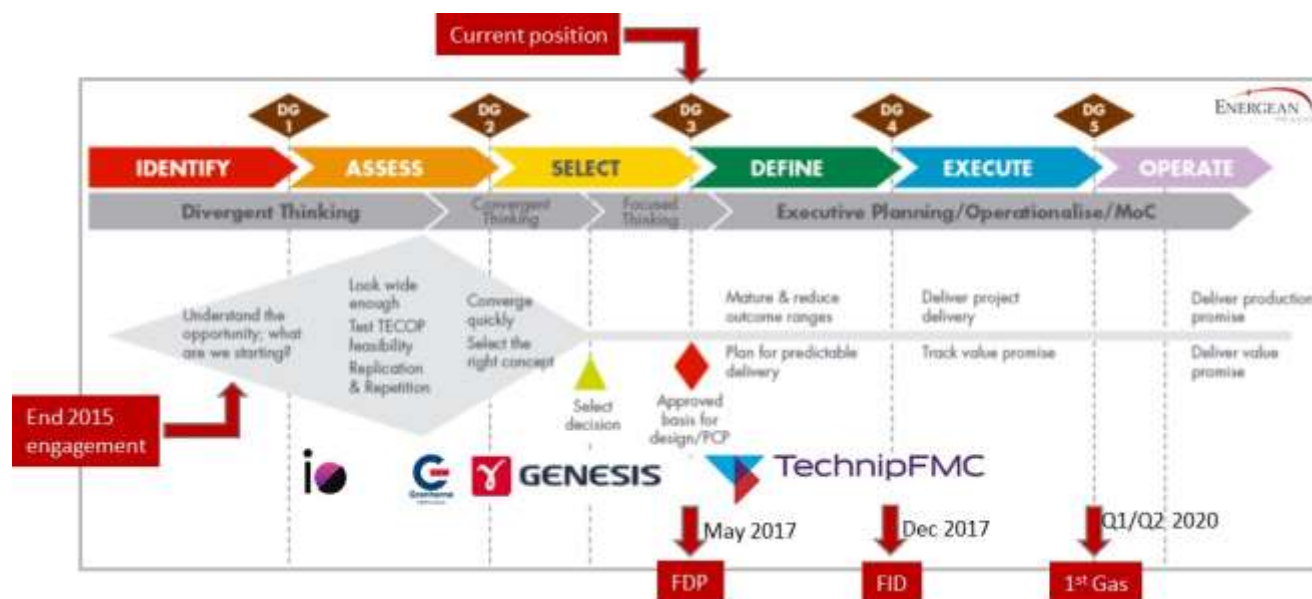


Figure 7-1 Energean Stage-gate Process (Karish and Tanin)

Initial development ideas were presented to the Israeli authorities towards the end of 2015 - when the preferred approach was to tie deep water wells back to an onshore processing facility near Haifa. This early work demonstrated that a commercial project could be identified and allowed Energean to pass through Decision Gate 1 into the ASSESS stage.

During the ASSESS stage, Energean used the company “io” (a UK based JV between GE Oil and Gas and McDermott’s International) to support its own development staff to identify all possible methods of developing the Karish and Tanin Leases at a relatively high level, further described in section 7.1.3. Value Drivers were defined. Energean screens its projects on the basis of value rather than simply against CAPEX. The “divergent thinking” phase shown in figure 7-1 was effectively complete by August 2016 where Energean choose to focus on Offshore focussed development strategies. Energean agreed a commercial deal structure with Delek/Avner around this time.

Energean then used Granherne (a specialist UK-based front-end engineering design house owned by KBR) to support progress through the “Convergent thinking” phase and hence to Decision Gate 2. The focus in this period was on investigating high level alternatives within the “offshore focus” theme and is further detailed in section 7.1.3. A “select decision” - for an FPSO-based development - was taken early December 2016 in conjunction with selecting a contracting strategy based on a partnership with the International engineering Contractor TechnipFMC.

Genesis (a UK-based specialist front-end engineering company owned by TechnipFMC) was appointed to support Energean during the remaining elements of the SELECT stage as well as to steer the project through Decision Gate 3 and into the DEFINE stage; following approval of this FDP by the Israeli government authorities. The main objective of this phase was to support the key technical decisions related to an FPSO-based concept as further detailed in section 7.1.5. These key decisions were formulated to ensure sufficient technical definition to obtain necessary approvals and to build clarity on the execution strategy (early engagement with yards, cost uncertainty reduction, good mitigation of project & production risks).

7.1.2 Value drivers

Energean’s project development process requires the company to select the preferred development option on the basis of value, rather than simply on the basis of cost. Clearly CAPEX and OPEX play a major role in determining value but they are not the only factors.

To assess value it is necessary to define the factors that contribute to or “drive” this quotient. Once these “Value Drivers” are agreed it is then possible to assess each option against each value driver. This assessment can be based on qualitative or quantitative measures. It is also possible to rank and weight the value drivers to differentiate between them.

For the Karish and Tanin development the following main value drivers were defined:

- Speed of gas to market: Deliver gas to the Israeli gas market as early as possible,
- Minimise CAPEX to first gas,
- Provide flexibility to increase production capacity as market demand grows,
- Ease of accommodating additional oil production from a deeper horizon,
- Minimise project execution risk,
- Ability to allow 3rd party access and/or attract external investments,
- Minimise environmental impacts during project development and production phases,
- Maximise/accelerate revenues received by the Israeli government,
- Maximise gas and liquid recovery from the hydrocarbon accumulations.

7.1.3 Assessment of potential development scenarios

Initial work focused on identifying a broad range of development approaches based upon the potential production facilities that could be used to process the produced fluids into sales (gas and liquid) and waste streams (water) and their geographic location. Boundary conditions were set by guidelines provided within the Israeli National Infrastructure Plan, TAMA/37/H. This document defines potential gas disposition points, pipeline corridors both onshore and in territorial waters and locations where fixed offshore and onshore structures/facilities could be located. A high level summary is provided in the figure below.



Figure 7-2 TAMA/37/H high level overview and boundary conditions

Considering the location of the Karish and Tanin fields, the options identified were constrained to the most northerly location allowed within this outline planning document. The option of landing produced fluids or positioning processing assets in central or southern locations was not considered.

During the ASSESS stage a wide range of development schemes were identified and evaluated at a relatively high level. All potential deep water facility types (Spars, FPU's, FPSO's, FSO's etc.) were considered as were wet and dry wells. The figure below provides an overview of the development schemes that were taken forward from this initial analysis and then considered and defined at a level sufficiently detailed to proceed with a preliminary ranking against company value drivers.

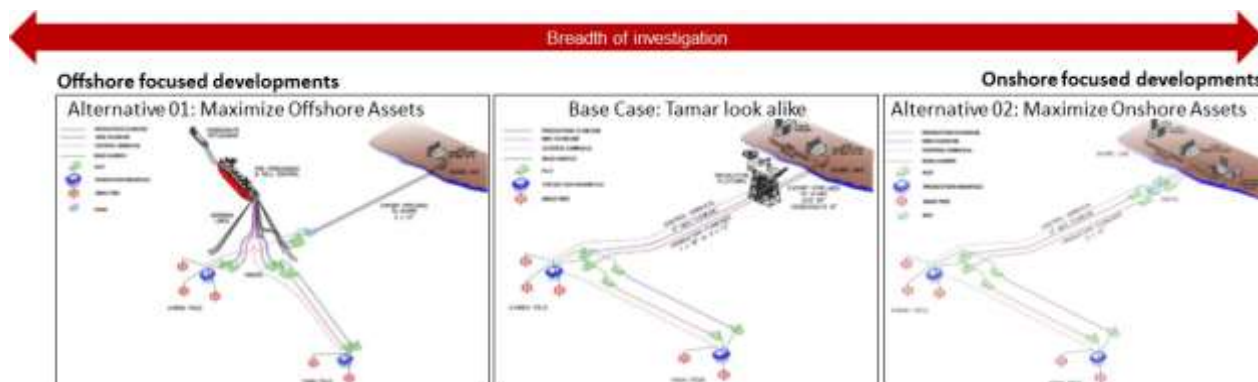


Figure 7-3 Assess phase - Development schemes investigated and ranked

Three extreme geographic scenarios were identified as illustrated above. A “Base Case” was defined that was based upon the development approach adopted by Noble Energy for the Tamar field. That is: a sub-sea development, tied back multi-phase to a processing/separation platform located on the continental shelf close to shore, with final processing of fluids undertaken onshore.

Two “extreme” alternatives were then defined and compared with this “Tamar look-alike” base-case, namely:

Alternative 1: Maximise Offshore Assets. In this scenario all separation and processing facilities would be located offshore at the Karish Main field. It was initially assumed that a new-build, operator-owned, turret-moored FPSO would be employed. The only onshore element would be a short length of the dry-gas pipeline (plus metering facility) required to connect with the INGL system at an enlarged Dor Gas Station.

Alternative 2: Maximise Onshore Assets. In this scenario all separation and processing facilities would be located onshore. In TAMA/37/H an area adjacent to the existing power station at Hagit is identified as being available for hosting such facilities. Use of this location would require pipelines and umbilical cables to be routed along a defined corridor between Dor and Hagit. It would also necessitate locating a pressure reduction facility offshore to ensure fluid pressures would not exceed the 110 bar limit imposed by Israeli legislation. As illustrated, a sub-sea pressure reduction station was envisaged as this would minimize environmental impacts and allow use of sea water to heat flashing fluids downstream of the required pressure control valve.

All development schemes were based, at that time, on the assumption that 5 Bcm/year could be sold into the Israeli market, and that 3 wells at Karish and 2 at Tanin would be required, in line with Noble and Delek’s initial assessment. Further details are provided in the figures below.

Deepwater wells & gas gathering with flowline tie-back to shallow water platform

- / Deepwater wells & tree system with gas gathering production manifolds in ~1,750m WD at Karish & Tanin
- / ~40km infield and ~100km tie-back flowlines to shallow water production platform
- / Multiplex optical/electro-hydraulic control system
- / 4" MEG flowline from SWP and continuous MEG injection at wells (hydrate mitigation)
- / Fixed jacket production platform in 100m
- / Export gas and condensate pipelines to shore (~10km) at Dor
- / Onshore gas and condensate pipelines to Hagit power station (~10km) and (condensate) to Haifa refinery (~20km)
- / NB: onshore costing basis as per WP study i.e. 2km gas line & 15km condensate line

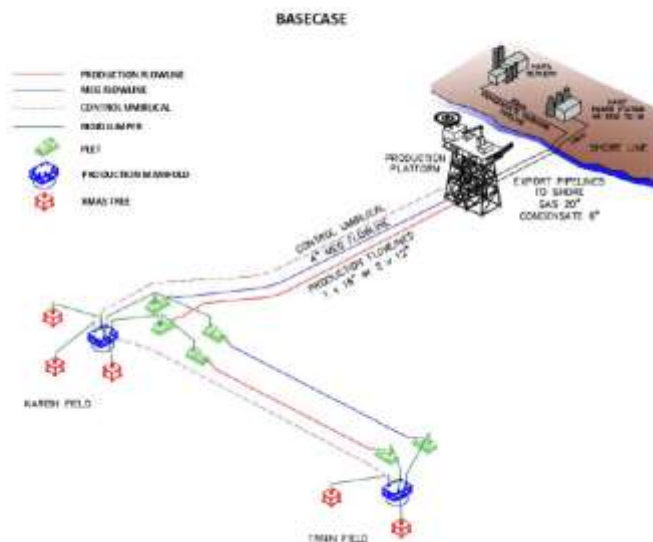


Figure 7-4 Base case - Tamar Lookalike development overview

Deepwater wells & gas gathering to FPSO located near the field and export pipeline to shore

- / Deepwater wells & tree system with gas gathering production manifolds in ~1,750m WD at Karish & Tanin
- / ~40km infield (T) and ~5km (K) tie-back flowlines and production risers to FPSO (turret moored)
- / Multiplex optical/electro-hydraulic control system
- / Fluid separation, condensate storage and offloading, gas compression at FPSO together with MEG injection/regen and host for subsea control system topsides facilities
- / Export risers and pipeline (~110km) to shore (Dor)
- / Shore crossing and barrier valve station
- / Onshore gas pipeline to Hagit power station (~10km)

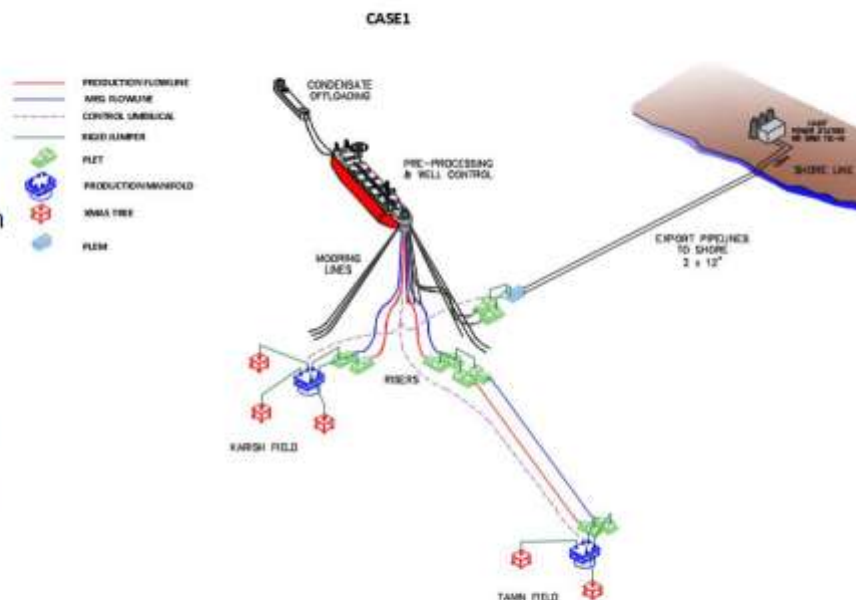


Figure 7-5 Alternative 01 - Maximise offshore assets

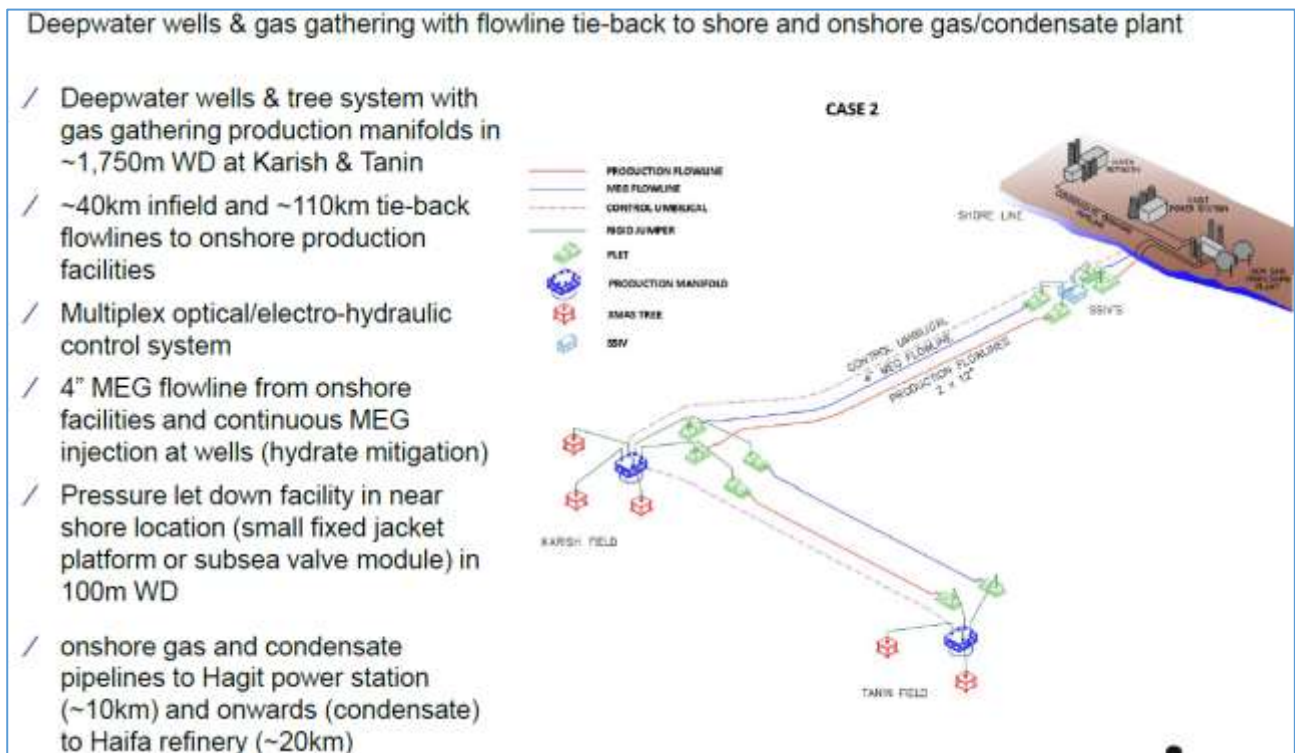


Figure 7-6 Alternative 02 - Maximise Onshore Assets

A ranking exercise against the defined value drivers enabled Energean to quickly and effectively differentiate between the above development schemes and identify areas of strength and weakness. The below figure illustrates how each of the 3 options were initially assessed against the highest ranked value drivers. It allows the strengths and weaknesses of the options to be visualized and compared on a spider-web diagram. This type of early focus on value is powerful as it then allows optimization studies to be defined on the basis of value improvement opportunities.

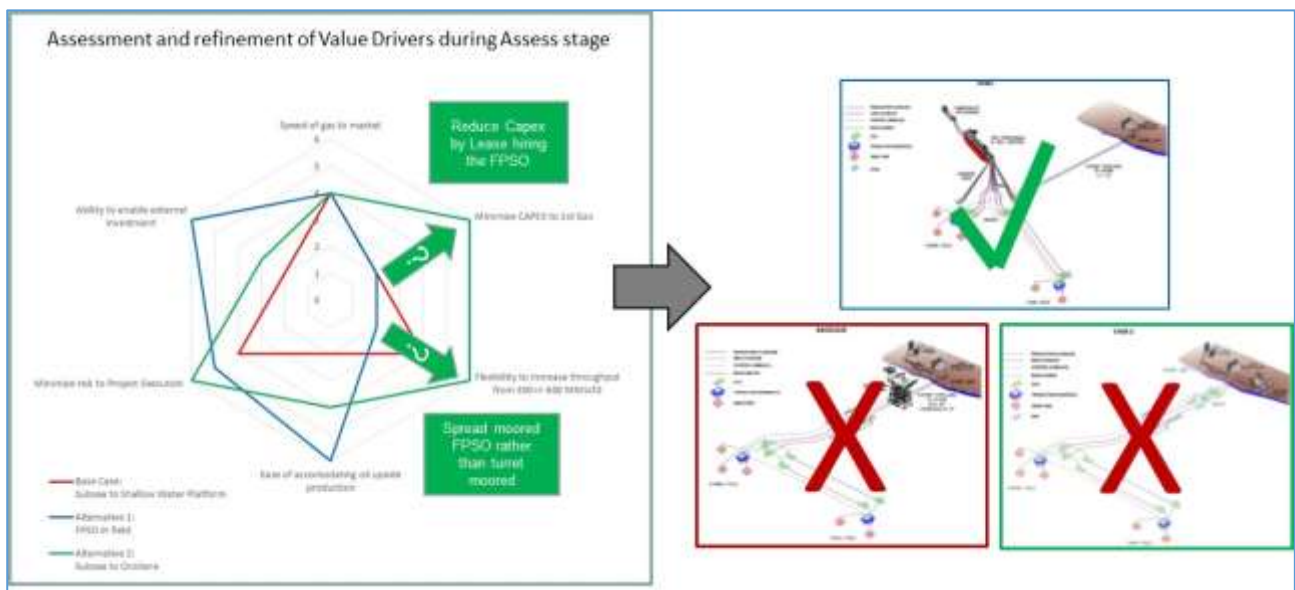


Figure 7-7 May 2016 Development scheme ranking overview

It became apparent that the Tamar look-alike development scheme (shown in red in the above spider-web diagram) was the least optimal approach. This development scheme appeared suboptimal with regard to most value drivers. Its inability to accommodate oil upside and potential third party tie in opportunities and/or investment, whilst carrying significant project execution risk and upfront CAPEX were its weakest aspects.

As initially assumed, the subsea to onshore concept (shown in green in the above figure) held significant attractions. It soon however became clear, as Energean improved it's understanding of the local Israeli environment, that an onshore development would put significant risk on the execution schedule and would require very strong stakeholder engagement capacity. It was felt that this could be challenging for a new-comer to the Israeli gas scene, particularly one committed to bringing new gas supplies to market rapidly in line with Israeli government aspirations.

The offshore concept also exhibited strengths, even though it was likely to be the most expensive. Energean decided to further deepen studies of this development approach with a focus on CAPEX reductions and ability to enable phased capacity build should the Israeli market not allow for 5 Bcm/year production on day 1. This would be required for it to have the highest overall value.

The “converging thinking” phase therefore started with the offshore concept as the preferred option. A number of critical areas for further investigation were prioritised - as listed below - and as outlined further in Figure 7-8:

- Pros and cons of different floater types,
- What is the potential for leveraging line pack in the dry-gas line? Could it help in reducing CAPEX?
- Can the topsides be minimized by sending to shore un-stabilized liquids?
- What other ways were there to reduce CAPEX to first gas? Could the FPSO be leased?

The main objectives of this work were:

- To understand if a spread moored solution was feasible, allowing for a simpler, less onerous floater design and project execution (as opposed to turret solutions), but also a simpler phased capacity build-up with heavy lift campaigns with the FPSO remaining on station,
- To understand if there were ways to reduce offshore topside complexity and costs, by leveraging synergies with existing onshore facilities: oil stabilization and power generation in particular.

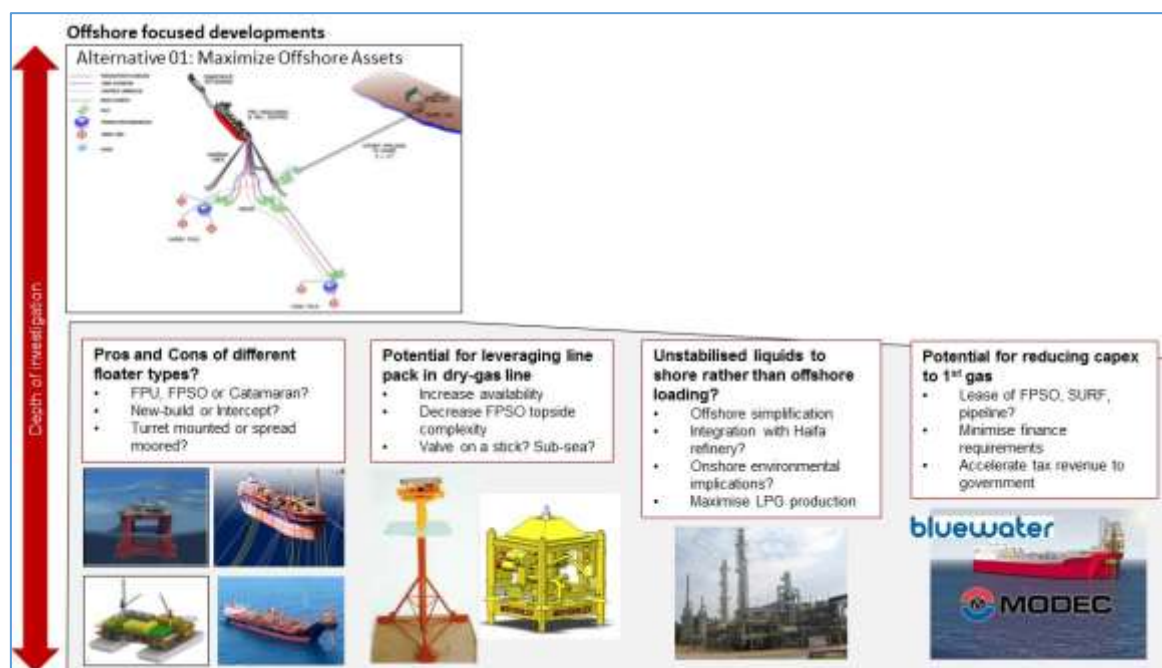


Figure 7-8 Convergent thinking focus areas

To address these issues two alternative, offshore-focussed, development schemes were prepared as visualised in Figure 7-9 below. These new discrete scenarios were used to determine how specific aspects drove project value.

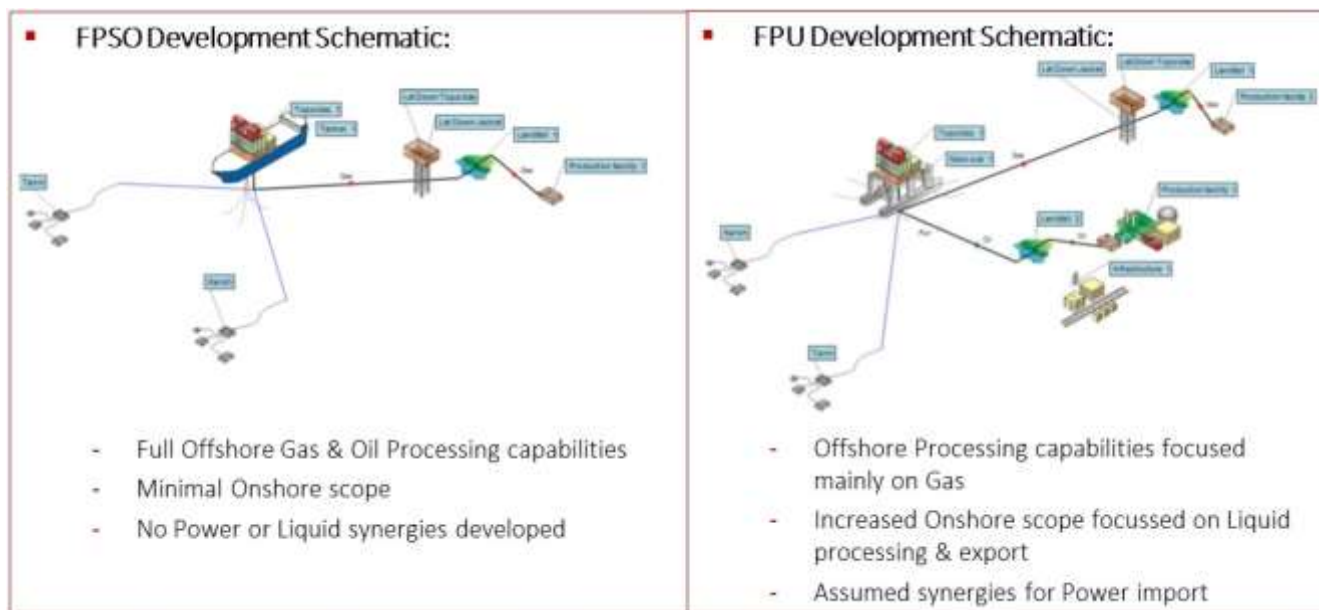


Figure 7-9 Offshore development focus alternatives considered

The work undertaken by Granherne during the “convergent thinking” phase focussed on these two offshore development alternatives (FPSO vs FPU) and allowed a re-ranking exercise to take place (December 2016), following the same systematic process described above. During this re-ranking exercise the prior evaluations of the “base case: Tamar lookalike” and the “Focus on onshore (Alternative 2)” development schemes were revisited for completeness and to reflect the team’s better understanding of the project environment. The outcome is shown in Figure 7-10.

The main findings of the Granherne work are outlined below and further addressed in section 7.1.5:

- A spread mooring solution is feasible using typical Aframax size tankers or larger, and without increasing significantly the costs of the production and export riser systems,
- The FPU alternative is penalized by high costs for the floater and the liquid line to shore, as well as a rather limited flexibility to ramp up in the later years due to significantly lower deck space availability and topside weight constraints (maximum and centre of gravity),
- A shallow offshore platform (or sub-sea valve) to maximize usage of line pack does not lead to significantly improved reliability or reduce further the FPSO/FPU topside complexity/CAPEX.

Energean also engaged in parallel with the owners of the Haifa refinery and key governmental authorities to gauge market interest/acceptance of Karish-area hydrocarbon liquids, in a partly stabilized condition, being fed to the existing refinery for final processing. This work concluded that management of unstabilised liquids onshore, either at the Haifa refinery or in a new onshore processing facility located at Hagit, would be unpopular with local stakeholders – who have strong environmental concerns – and was therefore not pursued further.

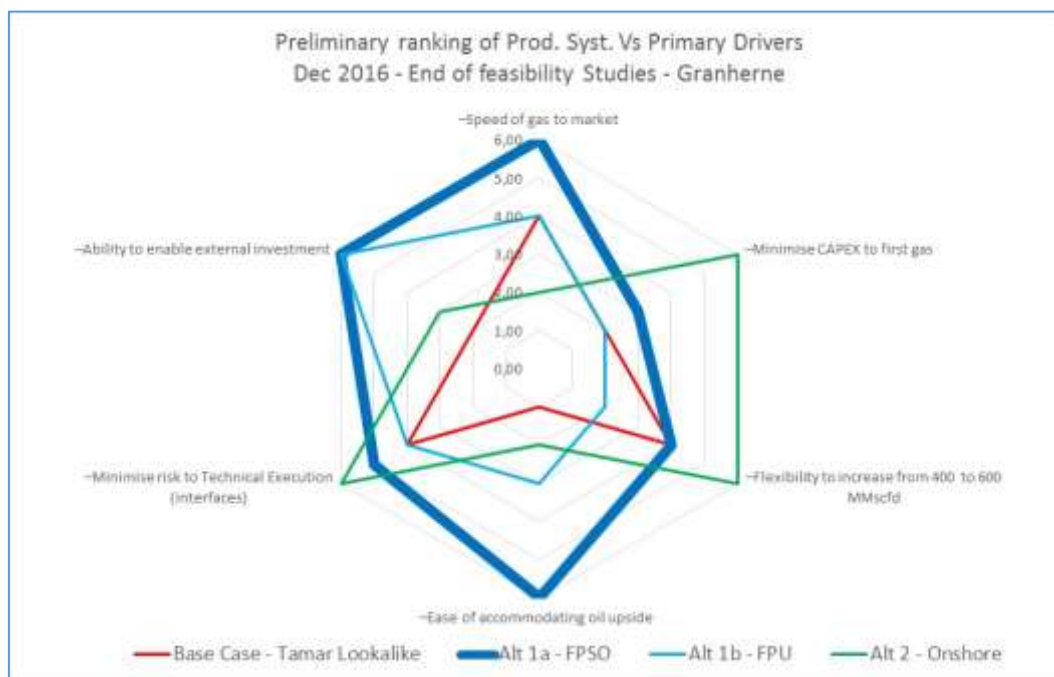


Figure 7-10 Dec 2016 Development scheme ranking overview

In the final analysis – illustrated above - the FPSO-based scheme clearly outperformed the FPU-solution. The “onshore focused development (Alternative 2)” was seen as less attractive than previous evaluations, being penalized for schedule uncertainty (onshore permit approvals) and ability to accommodate oil upside potential.

7.1.4 Rationale for selection of an FPSO-based development

The main advantages of the FPSO-based development over the other schemes are summarized below:

Schedule to first Gas and Project Execution risk reduction: A significant advantage of the FPSO scheme is that it minimizes work required to be executed in the field. All processing equipment is located on the FPSO and these modules can be constructed, hooked-up and commissioned in a remote location under controlled conditions. This provides significant benefits with regard to schedule compared with the alternatives. This is particularly so when compared with the approach used for Tamar. In this development significant activities had to be undertaken in deep water, on the coastal shelf and onshore, with multiple pipelines connecting the various components together. The only scheme that could deliver a schedule of around 30 months from FID to 1st gas is that involving use of an FPSO. An early 1st gas date accelerates the point where competition is introduced into the Israeli gas market.

CAPEX to first gas: Whilst Feasibility Engineering work showed that the FPSO scheme is slightly (+10%) more expensive than the Tamar look-alike and substantially more expensive (+30%) than the onshore option, it is possible to structure the project so that CAPEX to first gas is lowest for the selected approach. In many FPSO projects around the world Operators choose to employ a leased FPSO rather than a purchased unit. This minimizes funding required and the size of the project sink. Hence it is advantageous to the Operator and investors. Similarly it accelerates government revenues by reducing CAPEX depreciation in the initial years of production. None of the other development schemes considered provide opportunities to lease rather than purchase facilities. Whilst leasing an FPSO provides potential benefits it is currently assumed that the Karish FPSO will be purchased by Energean. Hence CAPEX Assumptions in the included economics are considered “worst-case” and conservative.

Liquid export considerations: The Karish Main C reservoir contains a richer dense-phase fluid than any other field found to date offshore Israel. It is clear the C reservoir has been charged from a thermogenic source as well as a biogenic source (that typically delivers 0 to 5 bbls/mmcsf). After processing, the gas produced from the Karish C reservoirs will generate some 20 to 26 bbls/mmcsf of hydrocarbon liquid (with an API gravity of around 50°) that should have an assay similar to crudes produced worldwide that sell at a modest premium to Brent. By using an FPSO it will be possible to market this crude stream worldwide and hence obtain the best

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possible price. If the liquid stream were produced onshore it would have to be either sold locally or an export terminal developed with significant cost, land use and hence environmental implications. Also placing the FPSO close to the fields will make tying back potential deeper oil play discoveries simpler and more cost effective.

Third party access: Another significant advantage of the FPSO scheme is the opportunity to tie back 3rd party discoveries offshore. With a multi-phase system, it is very difficult to manage the introduction of multiple fields owned by different companies into a single gathering system. In the north of Israel many exploration prospects can be mapped from available seismic. In general these are relatively small compared with the large structures drilled to date. To ensure that these prospects are drilled a means of commercializing them needs to be available. By placing an FPSO at Karish, Energean will make available offshore infrastructure into which 3rd party discoveries can be tied, at a cost that should allow even very-small discoveries to be commercialised. Energean has sized the planned FPSO to allow its processing capacity to be expanded; the proposed 24"/30" pipeline will be able to handle (without compression above 135 bar) production rates > 800 mmscf/day. This capacity could be further extended via the introduction of compression. The ability to attract 3rd party production and hence a tariff-based revenue-stream is good for the Karish and Tanin investors and also very good for the Israeli government as it should increase its commercial gas resources and hence period of self-sufficiency.

Technical risk: The most technically challenging element of any deep water gas project is the management of hydrates and slugs generated by the use of long, multi-phase, pipe lines. The Tamar project stretched the technical envelope of deep water projects substantially by delivering fluids to a shallow-water platform over a distance of 145 km. Use of a floating structure in the vicinity of the field is a much more common approach, one that has been mastered over the last 25 years. There are more than 20 floating units worldwide in water depths greater than the Karish field. In terms of capacity the Karish FPSO when fully expanded would have a capacity very similar to the average of the 200+ floating systems installed in all water depths. It would be of below-average capacity for deep water units. If the Tanin field were developed directly to shore it would have multi-phase lines similar in length to Tamar and hence amongst the longest and most difficult to manage in the world.

Reservoir Management and Performance: By placing the FPSO close to the reservoir to be produced it is possible to draw the reservoir down to a lower pressure at abandonment than if the fluids are produced via long multi-phase lines, should aquifer support be weaker than at Tamar. This ensures that recovery factors and hence reserves are maximized even if aquifer strength is low. Energean estimates that in the license period 10 to 20% additional recovery will be achieved by using an FPSO rather than a Tamar look-alike development scheme if aquifer support is poor. This benefit would be less pronounced if pressure depletion is minimized by a strong aquifer. However even in this case the advantage of low pressure drops between the wells and the treatment facilities is significant. Low pressure drops ensures back pressures are minimized and hence well deliverability increased. This allows wells to be deferred in time and to provide larger swing capacities. Alternatively, it allows processing to occur at higher pressures, resulting in smaller equipment, more efficient processes and hence less environmental emissions.

Environmental footprint: Using an FPSO located 75km from the Israel coast should result in the development having very low environmental impacts, substantially less than the other schemes considered. Environmental impacts should be lower during all project phases: construction, operation and abandonment. As no fixed platform is required and suction piles will be employed for the FPSO mooring system a small fleet of marine vessels will be required during construction/installation. This will result in low noise and pollution levels. The FPSO scheme also limits the potential for oil pollution resulting from pipeline leaks. Hydrocarbon liquids are not transported to shore and hence the consequence of any spillage is significantly reduced. The FPSO scheme also allows reservoir pressure energy to be employed more effectively reducing overall power requirements and hence emission levels. Importantly, the onshore and coastal project scope and hence environmental impact will be small. This is critical as not only will it ensure that environmental impacts are minimized but should aid in the obtainment of permits and hence support a fast-track project. The lowest CAPEX approach would have been to treat all fluids onshore but clearly this would have had the most significant environmental impact and hence was excluded.

Abandonment: Although abandonment should not occur for at least 30 years (i.e. well after the initial Leases expire in November 2044) the use of an FPSO, rather than a fixed platform, clearly will simplify the engineering involved in removing the facilities. An FPSO can simply be disconnected from its mooring and risers and

towed to shore or a new working location. A fixed platform requires significant resources to remove and hence has a significantly higher cost and potential for environmental impacts.

7.1.5 Key decisions addressed during the select phase

The previous section explains - at a high level - how an FPSO-based development scheme was selected. As the project passed out of Feasibility and into the Concept definition phase, Energean introduced a “decision based” project-management approach, which is illustrated in the figure below.



Figure 7-11 Select phase decision focused management

Use of this type of rigorous structure is considered “best practice” and aids in the prioritisation of the engineering work undertaken during the “Select” Phase. It develops sufficient evidence to allow the Energean project team to document and then defend, the key decisions required at this critical point of the project. It is particularly important when working to an aggressive schedule. It avoids the execution of unnecessary or unfocussed work and ensures that significant elements are not omitted that would require change to be introduced in a later phase.

The facilities development scheme was split in 4 main subproject scopes (see Table 7-1) and each main decision to be made during the Select phase agreed and described. Each of these decisions has a record sheet that helps staff understand what alternatives were available, what work was required and then executed and where to find the key assumptions data and results. A template is shown below.

Table 7-1: Karish and Tanin sub-project scopes

Cat.	Subproject Scopes
A	Subsea umbilical, Riser Flowline (SURF) + Subsea Production System (SPS)
B	Process Topside FPSO
C	Hull & Mooring FPSO
D	Export System

	Karish & Tanin Development Decision Record Sheet <i>Energean Doc No: AAA - AAA - AA - AAA - NNNN</i>	

Decision ID no:	Decision Required:			Rev:
Options Available:				
Sub Scope Affected	☐	A: Subsea umbilical, Riser Flowline (SURF) + Subsea Production System (SPS)		
	☐	B: Process Topside FPSO		
	☐	C: Hull & Mooring		
	☐	D: Oil & Gas Export Systems		
	☐	Others:		
Decision Background & history:		Affected Value Drivers		
		Speed of gas to market ☐		
		Minimize CAPEX to 1st Gas ☐		
		Flexibility to increase throughput ☐		
		Ease of accommodating oil upside production ☐		
		Minimize risk to Project Execution ☐		
Work Plan / Activities performed:		Givens/Boundary Conditions:		
Document References: <i>(list all of the documents you wish to invoke to support the decision making)</i>				
Ref [XX]	Ref Title	Doc Number - Rev	Company	
Findings: <i>(Use the Ref[] to make text concise)</i>				
Related Decisions: <i>(when applicable)</i>		Related Risks: <i>(when applicable)</i>		
ID No	Decision Title			
Recommendation:				
DECISION MADE AT APPROVAL GATE				

Figure 7-12 Decision Record Sheet Template

All decisions that have been identified and addressed prior to submission of this FDP are listed below. All Decision Record Sheets prepared are provided as attachments to the FDP. The decisions highlighted in **Bold red** text are considered the most critical and short summaries of these issues are provided.

Table 7-2: SURF related decisions (cat A)

ID	SUBPROJECT SCOPE	DECISION NEEDED
1	A	Method of tying back additional Karish & Karish North wells beyond the initial 3 wells envisaged.
2	A	Define hydrate management strategy for Karish sub-sea gathering system.
3	A	Define hydrate management strategy for Tanin sub-sea gathering system.
4	A	Select the optimal riser technology to be used
19	A	When is geo data to be acquired and what is the survey scope - for Karish only
23	A & D	Is there a requirement for installing SSIV's on the incoming and outgoing pipelines?
24	A	What Number, size and location for planned and/or possible tie-backs from satellite fields to the Karish FPSO? Including requirements for a potential future oil development of Karish deep.
29	A	Decide between horizontal and vertical tree's for Karish wells
30	A	Decide between Cluster manifold or on template manifold

Decision 2: the hydrate inhibition strategy for Karish will rely on the natural heat available at the well head (~55-65°C, see Section 6), sufficient to offer a sufficiently wide operating envelope thanks to the short distances between the well and the FPSO (<5km) and a high performance wet insulation system. This removed the need for continuous MEG injection subsea and the associated regeneration and reclamation systems.

Decision 3: the hydrate inhibition strategy will rely on Direct Electrical Heating of the 40km long subsea flowlines. This technology is more attractive than a traditional MEG system. It removes the need for retro-fitting a conventional MEG reclamation system offshore on the FPSO as part of the Tanin development. It will also be unaffected by the exact WGR that the Tanin wells will eventually exhibit. The technology is already mature in similar applications; further advances are expected in this technology in the next 10 to 15 years. This decision reduces the amount of pre-investment required in the Karish FPSO structure and topside utilities. Space for a MEG system has however been retained in the FPSO layout in case a 3rd party field requires such technology for commercialisation.

Decision 24: The 3 planned Karish Main wells will be developed in a tight cluster arrangement using a standard 4 slot subsea manifold, a dual production riser system and a dedicated umbilical. Tanin will follow the same approach. Provisions for 4 additional production risers and 2 umbilical's is included in the balcony design and will allow sufficient flexibility to cover upside tie-back opportunities around the FPSO location. The gas export balcony will be placed on the opposite side of the hull to minimise interference with the subsea production system and will have provision for 4 risers; two dedicated to the main dry-gas pipeline to shore and two spares. These could be used for establishing an export route from the Karish FPSO or for further increasing the capacity of the pipeline to shore.

Table 7-3: FPSO topside related decisions (cat B)

ID	SUBPROJECT SCOPE	DECISION NEEDED
5	B	Can project Value be increased by undertaking part of the required processing onshore? Which processing could be relocated?
6	B	Define heating requirements and technology upstream Hydrocarbon Dew Pointing unit?
7	B	Are the benefits of installing multiple dew pointing trains rather than a single 400 mmscf/day unit sufficient to overcome the complexity/cost increase?

9	B	What hydrocarbon dew point technology will be used for the primary processing train? Should the back-up train use the same or different technology?
10	B	What is the best way to provide additional processing capacity if required, both oil & gas?
18	B	What is the optimal water dehydration technology to be employed on the FPSO?
26	A & B	Which equipment will be spared?
31	B	Decide driver selection for the export compressors

Decision 5: as previously mentioned shifting oil stabilisation to shore was not demonstrated to be financially beneficial and introduced schedule risks due to increasing the complexity of the permitting process to be followed.

Decision 9: Joule-Thompson (JT) and the Turbo-Expander (T-X) based hydrocarbon dew-point schemes were studied and compared. JT was shown to be the most robust process. T-X based systems at the very high inlet pressures expected was unproven and in any case provided less flexibility to cope with turn-down requirements or offer flexibility in system back pressure.

Decision 31: An electric driven solution has been selected for the Karish FPSO. This solution provides the highest reliability with the lowest maintenance costs, whilst avoiding excessive pre-investment in power turbines on day 1. An electrically-driven export compressor arrangement with full redundancy is planned that could evolve into a 2x50% arrangement if a second gas processing train were added.

Table 7-4: FPSO hull related decisions (cat C)

ID	SUBPROJECT SCOPE	DECISION NEEDED
12	C	Is the FPSO hull to be spread moored or turret moored?
13	C	Should the FPSO hull be a new build or be based upon an intercepted oil tanker? What are the pros and cons of the two approaches and which is most in line with the defined Value drivers?
14	C	Should the FPSO hull be of traditional design or are their advantages to introducing enhanced features?
25	C	Where will the FPSO be located and in what orientation?
27	C	What size of accommodation will be installed?
32	C	What is the optimal storage oil capacity of the FPSO Hull?

Decision 12: a spread moored solution has been analysed and is confirmed feasible given the met-ocean conditions of the area. It is cheaper and lower risk than a turret moored solution, which in case of failure can lead to major downtime (i.e. Jubilee FPSO). The hull design adopted is larger than strictly required and hence exhibits reasonable motions at the riser hang-off even under extreme weather conditions. Lazy-Wave Steel Catenary Risers will be employed and provide for a very robust design. Oil cargoes will be loaded infrequently due to low production rate and large storage and hence a mooring buoy will not be needed.

Decision 13: a new-build hull will be employed giving a design life of 35 years with no need for the vessel to be removed from station during this period. An existing design (from Inoceen – a partly owned subsidiary of TechnipFMC) will be employed, reducing risk and accelerating design and classification approval. By adopting a new-build rather than conversion approach technical risk will be reduced by removing from the project brown-field scope.

Table 7-5: Pipeline related decisions (cat D)

ID	SUBPROJECT SCOPE	DECISION NEEDED
15	D	Is availability significantly improved by installing a shallow water pressure reduction pressure hence allowing the deep-water pipeline section to be operated closer to its design pressure?
16	D	Location of connection with onshore INGL network
17	D	Is there Value in installing a small diameter liquids line in parallel with the main export gas line? This could be used should a direct supply of liquids to the refinery be justified
20	D	What is the optimal export pipeline arrangement (diameter and number)?
21	D	Where will interface between Technip and local onshore contractor for gas export pipeline be?
22	D	How will gas export pipeline integrity be managed - pigging, RBI etc.?
28	D	What onshore equipment is required and will it be installed at the coastal block valve station or at Dor Gas Station?

Decision 15: Analysis showed that the increase in line pack achieved by introducing a pressure let-down facility close to shore (platform or sub-sea valve) was not sufficient to justify inclusion of this additional asset in the project scope. A marginal reliability improvement was forecast and close-to-no FPSO topside savings. The dry gas line will therefore run directly from the FPSO to the Dor Valve Station with no intermediate pressure reduction. Modest line-pack will be available limited by the need to operate the shore sections below 110 bar. This will help manage daily flow fluctuations whilst maintaining production through the FPSO as stable as possible. Management of the line pack will require the establishment of good interfaces with INGL.

Decision 20: a 24"/30" dry-gas pipeline with two 16" risers offers the optimal configuration for the development. It will allow the maximum capacity to be increased from 650 mmscf/day (1 riser – 130 bar inlet) to > 800 mmscf/day (2 risers – 135bar). This line can be installed by a mid-range deep water offshore pipe lay vessel. Selection of a larger diameter would have led to a significant cost increase - only 3 vessels worldwide are capable of installing such lines - and an additional major project interface – TechnipFMC does not operate any of these vessels.

7.2 Overview of the selected Karish Main development scenario

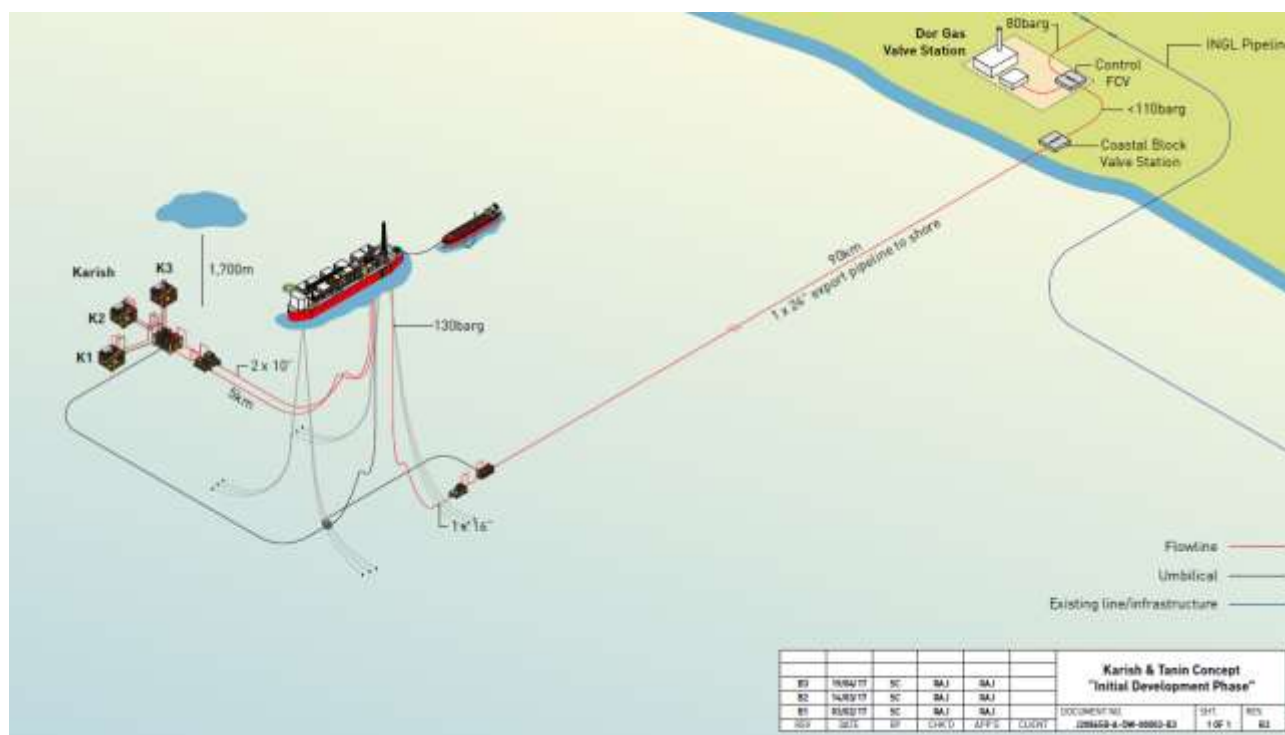


Figure 7-13 Initial Development Phase – Karish Main Only

As outlined earlier and illustrated above, the proposed “Initial Development Phase” scheme centres around the installation of an FPSO approximately 3km south of the Karish Main field. The main building blocks of the initial production system are:

- **Karish Main Subsea Production System:** wells, spools, manifold, risers
- **FPSO hull & topsides:** hull, mooring, accommodation, topside process facilities and utilities, offloading system,
- **Dry-gas pipeline system:** riser, sub-surface safety valve, deep water section, shallow water section, an “interface facility” with INGL at 10km location, beach crossing, onshore pipeline, coastal valve station (CVS) and extension of Dor valve station (DVS)

This section describes each of the above building blocks providing details of the key features. A more detailed description is provided in section 7.5.

7.2.1 Subsea production system

The Karish Main field will be developed via three new deviated wells drilled in a tight cluster arrangement around a standard 4 slot manifold. The existing Karish-1 exploration well will not be used. Wells will be connected to the manifold by short rigid spools of 60-80 m length. Each well will have a production choke and a wet gas meter enabling well and reservoir management activities to be performed.

The manifold will be provided with two headers and minimal automation requirements. It will be possible for production from each well to be routed to either header and hence either of the Lazy-Wave SCR's. This type of riser allows for the predicted motions of the FPSO and can contain the very high flowing and closed in pressures expected. Closed in pressures of the Karish Main wells will be in the order of 460 bar. The entire Karish Main subsea production system has been designed for the calculated CITHP.

The subsea system will be provided with high performance wet insulation (5LPP type). This allows the gas to retain as much heat-energy as possible as it flows from the X-mas tree to the surface choke. As illustrated in Section 6, FTHT's are expected in the range 50 – 65°C over the life of the Karish Main field. Calculated temperature losses will be minimal (10 to 20°C) due to the insulation selected and the short distances involved.

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Residence time in the sub-sea system is less than 15 minutes. The gas arriving at the FPSO will therefore be above the hydrate formation temperature. Acceptable “cool-down” times are calculated should production have to be shut-in unexpectedly.

Each of production risers is sized for 400 mmscf/day. This will ensure that they never bottleneck production capacity including should the Karish North and East exploration prospects be tied back in the future and gas sales volumes increased correspondingly.

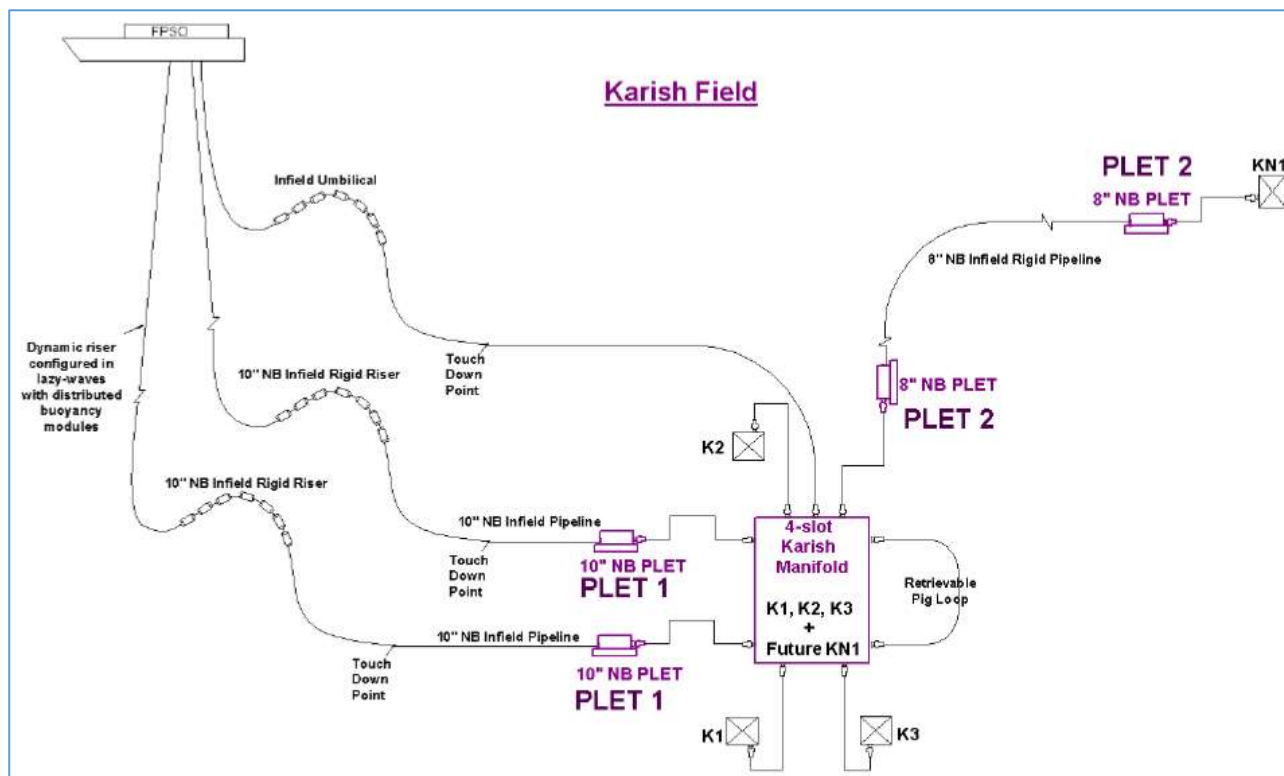


Figure 7-14 Initial Development Phase - Karish Subsea Production System

The Karish Main manifold will have a spare slot to allow for the simple hook-up of either a 4th well or a flow-line from an additional multi-well manifold. This slot could be used for wells from the Karish North and/or East fields, for dedicated wells used to accelerate B sand production or wells dedicated to the A sand should this upside potential be eventually proven. The same hydrate management philosophy based only on wet insulation will still be applicable. The Karish Main manifold can also be extended to add an additional pair of wells to the cluster.

7.2.2 FPSO hull and topside

A review of the market for leased FPSO's did not identify a unit of an appropriate specification that would come available before the planned start-up date and which could be retained at the Karish location for at least the duration of the initial Lease (to August 2044). Hence a new FPSO has to be developed.

The hull of the Karish FPSO will be a new-build based upon an existing design from Inoceen (part owned by TechnipFMC). This design has previously been classified by DNV-GL. The FPSO will be moored with its bow headed west, facing the majority of severe weather conditions. With a new-build vessel, accommodation can be positioned at the bow and the flare at the stern. This is be the safest arrangement following an accidental gas release considering the prevailing westerly weather conditions. A vertical or cantilevered flare is envisaged and will have to incorporate security requirements (see section 11.5) as well as constructability and transportation aspects. The high level layout provided below demonstrates the main features.

The FPSO deck area is split into three sections of roughly equal dimensions:

- one third is for utilities, including power generation, and is located adjacent to the accommodation module,
- one third is dedicated to further growth opportunities and essentially will be empty at start up; this section is mid-ship,
- one third for the gas and oil processing equipment associated with the initial development phase; this equipment and the associated risers is located at the stern of the FPSO as far from the accommodation module as possible.

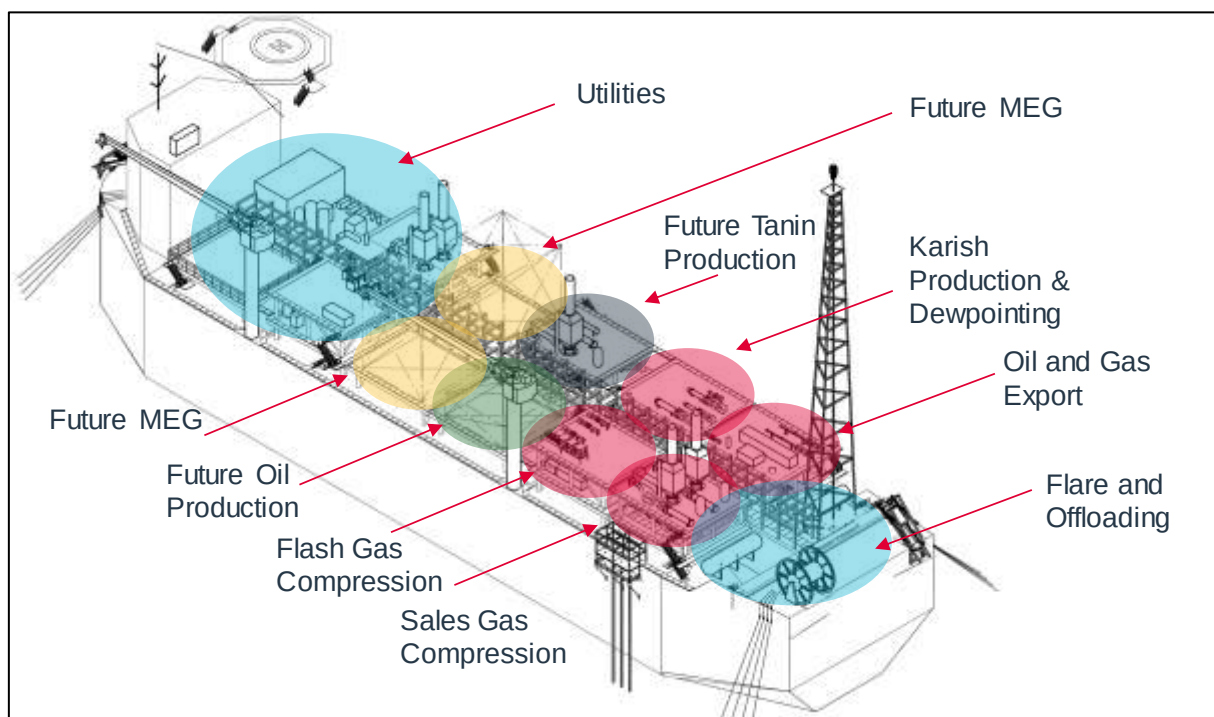


Figure 7-15 Conceptual layout of Karish FPSO

The FPSO will have 1,000,000 bbl storage capacity located in 15 cells built into the hull. This storage will be employed as follows:

- 500,000 bbl of “export” crude in 5 central, 100,000 bbl tanks, ready for offloading to a sales tanker. It is envisaged that parcels between 350 kbbls and 450 kbbls will be loaded over a 24 hour period,
- 300,000 bbl of crude undergoing final polishing (water removal) in 6 side, 50,000 bbl tanks. This crude can be pumped to the export tanks after water has been drained from the tank bottom,
- 100,000 bbl of mixed crude/water discharged at 10 psi RVP from the topside crude stabilisation system. Water and crude are separated by gravity; crude will be extracted from the top and water from the bottom. The water/oil interface will be maintained at a level approximately 1/3rd from the bottom,
- 100,000 bbl of produced water undergoing final “polishing” (oil removal). This water can be recycled back to the process train, can be fed to the oil-centrifuge package or pumped over board if it meets the discharge specification of 15 ppm.

Storage for MEG (lean and rich), diesel, methanol, slops from machinery spaces and open drains, etc. will also be provided in the hull. Ballast tanks will be provided between the skins of the double hull (side and bottom).

Karish Main fluids will be processed through a single gas and a single oil train designed to give high availability and a robust operating envelope. The gas processing train will consist of the following elements:

- A two-stage, Joule-Thomson process, incorporating a MEG loop has been selected for the water and hydrocarbon dew point gas processing, based on its proven performance, simplicity and it's

good turn-down. A Turbo-Exchanger based scheme was investigated but rejected as discussed above. Molecular Sieves were also investigated but excluded due to weight and cost,

- Dry gas is transferred to the sales pipeline system by two 100% capacity, single-stage, compressors, equipped with variable speed electric motors. Full redundancy is provided to give high availability. The system will have excellent turn down capacity.

The oil stabilization train is designed to be as simple as possible. It is comprised of 4-stages of two-phase separation (gas/liquid) with associated flash gas recovery compression. Water/oil separation is performed in dedicated storage cells. This guarantees:

- high availability of the liquid system, key to the good availability of on specification gas,
- good tolerance to possible emulsions which would make interface level difficult in small pressurized vessels,
- high turn down capabilities,
- a pragmatic way of building robustness for unknowns, whether it be higher WGR's or OGR's.

Flashed gas generated during the oil stabilization process represents approximately 3% of the total gas throughput of the installation. It is compressed using an electrically driven, 3-stage reciprocating machine, a robust approach for this type of low-flow, heavy, varying molecular weight gas application. Approximately 50% of the compressed flash gas will be used as fuel gas and the remaining will be spiked into the dry gas pipeline system, slightly increasing the calorific value of the sales gas stream transported to shore but remaining well within the required gas specification.

Production risers will land on the northern (starboard) side of the FPSO; the more sheltered southern (port) side being used by supply vessels for routine operations. The Gas export riser will be located at the stern end of the southern side. This dual riser balcony approach offers an optimal tie back arrangement (with regards riser/pipeline length) without increasing risk levels.

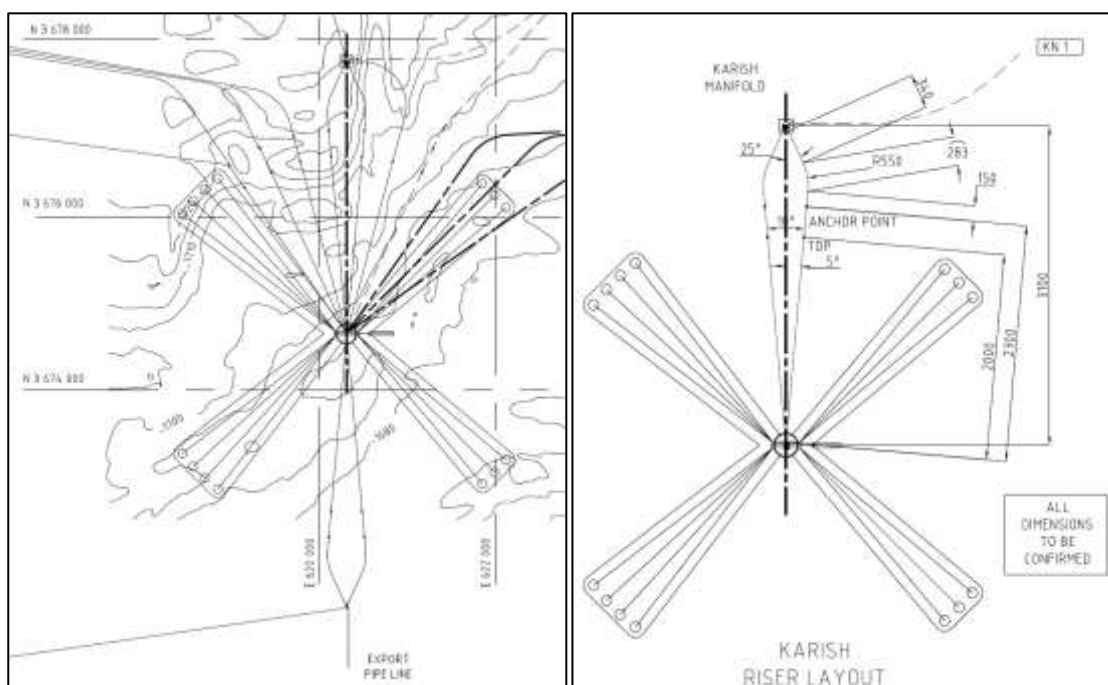


Figure 7-16 Field architecture preliminary layout

Utilities are standard and sized for the envisaged fully built-out production capacity of 800 mmscf/day (except in the case of Power Generation where space is provided for a 4th unit should a second gas train be added). The utility systems are relatively low cost but complex to expand later in field life. Their main features are:

- a closed-loop, hot-oil, heating medium system, recovering energy from the main power generation turbines (via WHRU's), increasing fuel efficiency and avoiding the introduction of direct-fired heaters,

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- a closed-loop, sea-water, cooling medium system removing the need for air-coolers and making use of seawater readily available at a relatively constant temperature of around 20°C. Heat exchangers will be shell and tube,
- a centralized hydraulic power system to support the cargo pump system, providing the most robust solution available in the market.

7.2.3 Dry-gas pipeline to shore

A single dry gas pipeline of 24"/30" (ND) will be laid from the Karish FPSO to Dor Valve Station (DVS). The line is split into 3 sections:

- Deep water section: approximately 80 km long from the Riser Base structure up to the planned INGL "interface facility" location, sitting at 60-100m water depth. This section of the line will be 24" until it passes on to the continental shelf and then increase to 30" diameter. The exact location of the diameter change has yet to be confirmed. For the FDP it is assumed that it is located 15km from the shore,
- INGL-owned shallow water section: approximately 10km long up to the costal valve station (CVS) and including the beach crossing. This section of the line will be 30" (ND). A provision to tie-in a manifold for 3rd party suppliers to access the near shore line will be provided at a distance 10km for the coast. Ownership of this section will be transferred to INGL post commissioning and start-up. It will be constructed by Energean using the same contractor who installs the deep-water section,
- Onshore section: approximately 2km long from the CVS to the DVS. This line section will be 30" ND. This section of the line will be owned by INGL. Agreement has still to be reached whether it is constructed by Energean or INGL.

A single 16" Lazy Wave SCR will initially connect the FPSO to the dry-gas pipeline. Tie-in points will be included to allow a second 16" riser to be installed in the future increasing capacity of the system from 650 mmscf/day to 800 mmscf/day. A single 20" riser cannot be installed with the envisaged TechnipFMC vessel. Mobilisation of a separate vessel is not cost effective. As the capacity of the dry-pipeline may never have to exceed 650 mmscf/day this phased approach appears optimal in any case, minimising CAPEX to first gas.

The pipeline will operate in dry service and will require minimal pigging.

Energean is committed to including in the dry-gas pipeline system, facilities that will enable the subsequent introduction of gas supplies from 3rd party fields located between the Karish Lease and Dor beach. This requirement has been identified by INGL who wish to avoid additional beach crossings and an onshore manifold in the vicinity of Dor.

A number of options have been considered with respect to the nature and location of the tie-in points as well as the size of the shared pipeline down stream of this point. Energean has agreed with INGL that the 3rd party "interface facility" will consist of two valved T pieces located at a distance of 10km from the shore. Between these T's, a full bore block valve will be provided. This arrangement allows either a sub-sea manifold or a riser platform to be installed subsequently without necessitating a shutdown of Karish production. Initially Karish gas will flow directly to the shore with the block valve open. Once 3rd parties access the system Karish gas could flow either via the new manifold/platform – by closing the in-line block valve – or directly to the shore. When the line is pigged gas will flow directly to shore.

Following interactions with INGL involving meetings with TechnipFMC and Wood Group in London, the benefits of a larger diameter pipeline in the near-shore (shared) section was identified. A 32" (ND) pipeline was suggested. After interactions with various reputable intelligent pigging companies it was concluded that a transition between 24" and 30" could be accommodated safely. Intelligent pigs are available (from, for example GE Oil and Gas) for this arrangement. Whilst it might be possible to pig through a 24" to 32" transition no commercially available pig could be identified. Hence, Energean has based this FDP on a plan to increase the line size to 30" further offshore than 10km to provide the same overall capacity as a 32" line gives from 10km. The exact transition distance will be determined when the lay barge to be used to install the shallow water section has been confirmed.

Other options considered are discussed further below in section 7.5.8.3 below. The arrangement of the agreed “interface facility is illustrated in Figure 7-17 below.

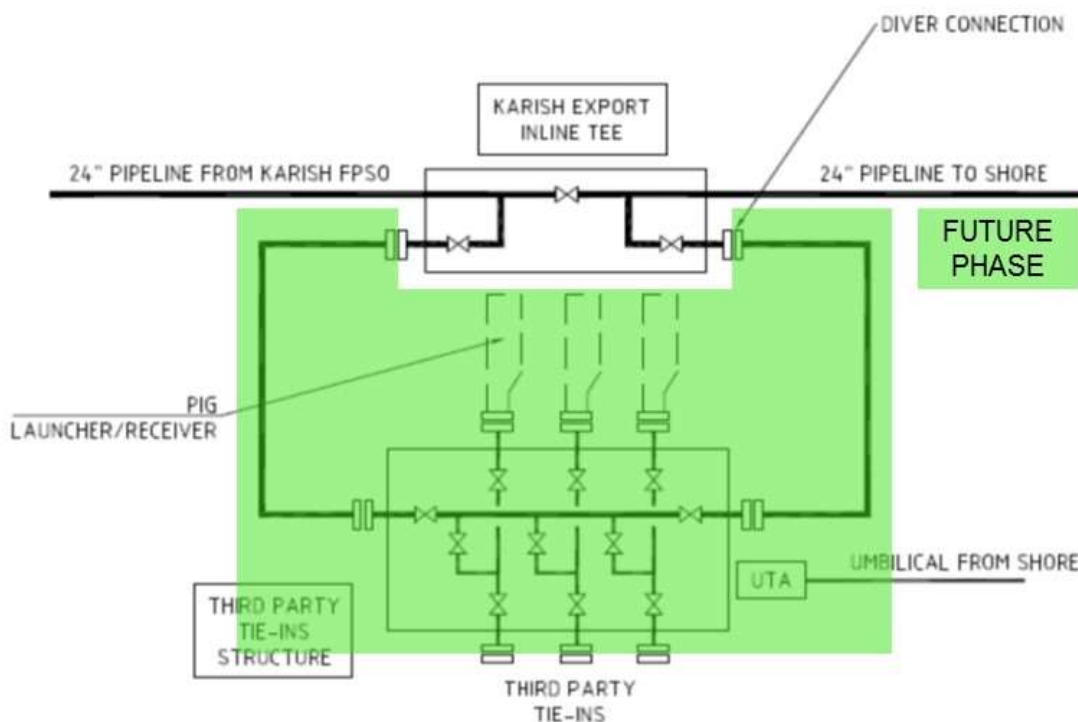


Figure 7-17 Export line transition between deep and shallow offshore sections

Figure Note: Proposed initial and future configuration from initial study work

The Coastal Valve Station (CVS) will be equipped with minimal facilities ensuring isolation between the onshore and offshore sections in emergency situations. Pig receiving/launching is not required at this location.

The Dor Valve Station (DVS) will have pig reception/launching capabilities. It will provide process flow metering and a control valve that can be used to either manage flow of dry-gas into the INGL transmission system or the pressure upstream of this valve. Heating may be required depending on the final gas temperature specification agreed and the predicted pressure drop over this flow/pressure control valve. The exact nature of the heating system will be defined in the next stage. Synergies with Noble’s Leviathan project will be leveraged if possible to reduce overall costs.

- it will provide a wider operating envelope with respect to gas rate turn down and earlier/prolonged formation water production,
- it will reduce the slug handling volumes to be managed via the inlet separation facilities of the FPSO. The size of these vessels should be minimised in light of their high design pressure requirements,
- it offers potential for flow segregation, should multiple fields produce to this system. This will enable various pressure regimes to be incorporated in addition to simplifying metering issues,
- it allows for pigging and hence improved integrity management of the high pressure wet service lines that rely on the effectiveness of a chemical-based corrosion inhibition system including routine pigging.

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The hydrate management strategy adopted currently for Tanin is active heating rather than the use subsea of MEG. Direct Electrical Heating (DEH) appears more attractive than Pipe-in-Pipe EHT due to the water depth in which the lines will be installed and the proven track record of this technology. As Tanin is unlikely to be developed for many years it is possible that an alternative technology will be available by that time. A new FDP will be prepared and submitted once the timing and final scope of the Tanin development is known. DEH (whose principles are shown in Figure 7-19) is specifically applicable to this system as the minimum sea bed temperature is high (~13oC) and the difference between this and the hydrate formation temperature (20 to 25oC) manageable. A conventional wet insulation system with insulation properties specified for Karish, paired with the ability to electrically heat is therefore attractive and cost competitive with a MEG-based solution. A MEG system, would require the installation of additional, heavy, topside modules prior to Tanin start-up. These would be more expensive than using a DEH-based approach. In addition a MEG-system would not be able to cater for the expected uncertainty in formation water production volumes that subtle structures such as those found in the Tanin Lease would have.

□ Principle of Direct Electrical Heating

- Current is sent through pipe = heat due to resistive losses
- Parallel coupling of pipe and sea = no need for electrical insulation on pipe
- Closed loop electrical circuit
- Technology is "open" for everybody to use

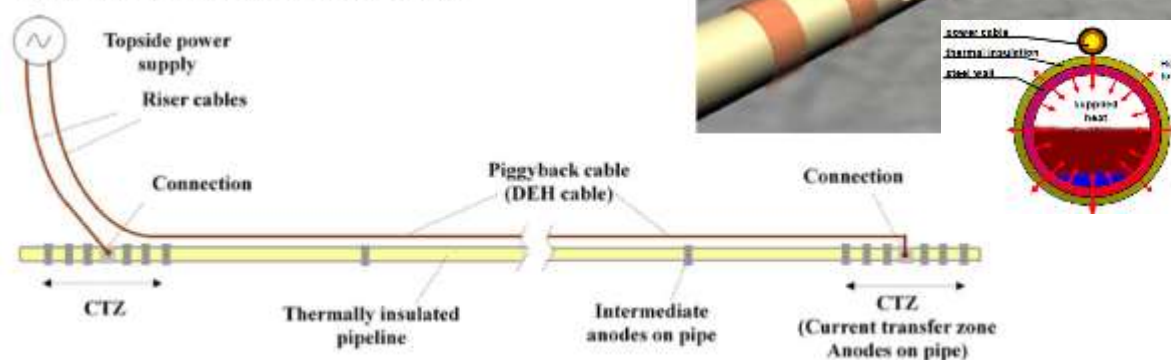


Figure 7-19 principals of Direct Electrical Heating

7.3.2 Karish North Subsea Production System

Karish North is the most attractive exploration prospect in the Karish and Tanin Leases. As discussed in Section 5, it contains significant volumes in multiple layers and has a very high POS due to the presence of DHI's comparable with those observed in Karish Main. Although plans for drilling an exploration well on Karish North have not yet been finalised it is very likely it will be drilled early, and definitely prior to, the Tanin development plan being finalised. As it sits close to the Karish Main development infrastructure – which have been sized for 800 mmscf/day – it would be tied back through these facilities. Due to the likelihood of its development, plans for a Karish North development have been covered in this FDP.

A 5.5km, 8" (ND), wet insulated flowline, could connect a KN-01 development well to the spare slot available on the Karish Main Manifold. Karish North production could flow to a dedicated Karish riser, with or without commingling with Karish gas, or could be commingled over both risers. The 8" line would allow production of 200 mmscf/day from Karish North. If after drilling it is concluded that Karish North (with or without Karish East) could support more than this rate a larger single line could be employed or the development of Karish North could make use of the expandability of the Karish Main manifold (i.e. run two parallel lines to Karish North where multiple wells could then be located). Karish North hydrates can be managed in a similar way to those in Karish Main, i.e. via wet-insulation and residence time management.

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7.3.3 FPSO Topsides

Production from Tanin and/or Karish North will arrive at the FPSO topside inlet facilities and will be routed either to the same production train as Karish or to a second parallel train that would likely have the same name plate capacity – 400 mmscf/day. A smaller train could be installed to minimise capex, but this would not fully utilise the upside capacity in an enlarged dry-gas pipeline system. A train with larger capacity could be installed if sufficient gas volumes are discovered to justify an export scheme, i.e. should rates above 800 mmscf/day be envisaged. All necessary provisions for space, tie-ins and utilities are allowed for in the design of the Karish FPSO for this second train. The two parallel gas trains would share the initial oil stabilisation facility that would be de-bottlenecked by increasing LCV trims. The decision to install this second train and hence increase capacity is not specifically related to the development of the Tanin or Karish North fields – these may be developed to extend the initial plateau as assumed in the described Reference-case – but rather the decision to increase gas sales due to increased demand for Karish and Tanin Lease gas in Israel.

It is unlikely that a third 400 mmscf/day sales-gas compressor would be required when the second gas processing train is installed. By providing in the initial development phase two 100% units equipped with variable speed electric drives, modelling work shows a third unit would not add significantly to availability. A review of recent European offshore gas projects has confirmed that export/sales compressors are not normally spared when they are specified in the same manner as the Karish units. This decision would be revisited prior to agreeing new sales gas contracts based upon run data and knowledge of the amount of spare capacity in other fields supplying gas to Israel at that time. Room has been left in the FPSO lay-out for a third unit.

One of the main reasons for using a spread moored FPSO rather than a turret-moored unit was to enable additional modules to be lifted onto the deck to support this type of expansion. The installation of the 2nd gas train is therefore considered perfectly achievable in light of the limited equipment to be added (see section 9.1.11 for more information). A 4th Gas Turbine Generator may also have to be added when ramping up. This is also not considered as a major issue as long as all electrical systems for this units are built in to the initial design. This ensures a 4th generator is not required initially and hence minimises CAPEX to first gas as desired.

7.3.4 Dry-gas pipeline system to shore

An additional 16" riser would be added to reduce pressure drop in the dry gas pipeline system and hence increase its capacity. With this addition the dry gas pipeline capacity (at a landing pressure at the INGL system of 80 bar) would increase to 800 mmscf/day (even with 3rd parties tied in as envisaged by INGL at a rate above 600 mmscf/day).

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On the southern balcony room will be provided to install two additional 12" gas export risers. Whilst all production from the existing Karish and Tanin discoveries is earmarked for sale in Israel it is possible that additional volumes, or volumes in nearby Leases, could enjoy an export quota. Energean believes it is prudent to allow in the design of the FPSO the facility to install two 12" export risers. These could tie into a dry-gas system created on the back of the significant volumes in Noble's Leviathan field, or to serve a smaller market (e.g. Cyprus) that Leviathan gas is unlikely to target. The position of the Karish FPSO makes it well placed to send gas to Cyprus and potentially Turkey.

7.4.2 Tie-backs to the Tanin multiphase Sub-sea Production System

The Tanin multiphase lines will pass through Block 12 where several mapped gas prospects are located. These prospects individually or combined are unlikely to support a commercial development unless they share infrastructure installed for Karish and/or Tanin. Two of the spare risers discussed in section 7.4.1 could be employed should a Block 12 development precede prior to development of Tanin. Should Tanin be developed or be in its planning phase then tie-in points will be installed in the Tanin 12" pipelines in the centre of Block 12. These would likely take the form of valved T's allowing tie-ins to be achieved without a Tanin shutdown. Exact details of the tie-in, use of the two lines and the metering systems required would be driven by whether the Block 12 prospects are explored by Energean or a 3rd party. Clearly it would be simpler to accommodate production if Block 12 were operated by Energean, but not impossible if operated by a 3rd party.

As mentioned above the Tanin manifold will be provided with a spare slot(s) and also can be expanded. Should all blocks identified in the Tanin Lease prove prospective the total number of wells eventually drilled could be as high as 8. It is however unlikely that all of these would be in production at the same time. The Reference-case covered by the FDP currently assumes 6 wells, 3 at Tanin A, 2 for Tanin C and a single well for Tanin B.

The eventual complexity of the Tanin/Block 12 sub-sea production system could also force a re-visit of the assumption that DEH is the most appropriate hydrate management technology. As the number of branches grows it is feasible that MEG injection at the end points may become the cheaper option. This will be studied over the years and of course prior to the development of Tanin A/B/C blocks.

7.4.3 Other flexibility incorporated in the proposed FPSO design

As mentioned above, whilst DEH is assumed as the selected basis for the planned Tanin development the FPSO has been designed to provide the flexibility to use MEG instead. Space and weight allowances have been incorporated in the FPSO hull and topsides for MEG separation, regeneration and reclamation. If not used for Tanin this space could be used for another, unidentified field that requires MEG for hydrate management.

In the FPSO hull, storage for 10 days rich and lean MEG has been accommodated. This ensures that a failure of the MEG regeneration unit (which is not spared) should not require immediate cessation of gas production. Lean MEG can be pumped directly from storage to the JT dew point management train with wet returns stored for future regeneration.

Space has also been provided for an expansion of the oil production capacity of the FPSO. As mentioned above Karish C reservoir fluids are richer than other fields discovered in the Levantine basin. It is possible that these liquids have migrated into the deeper reservoir units of Karish through the deep seated faults that form the northern boundary of Karish Main and appears to isolate Karish Main from Karish North and Karish East. Energean envisages that after developing the Karish Main field it may drill a deeper exploration well to investigate a structure mapped at the Cretaceous/Jurassic. Oil volumes discovered in the Karish C unit may have been generated in the Jurassic. Onshore, reservoir quality sands and carbonates have been discovered in the Jurassic and Cretaceous. By employing an FPSO at Karish Energean has minimised the oil reserves that would have to be discovered to commercialise such a deeper play.

7.5 Detailed description of FPSO based field development scenario

7.5.1 Met ocean Conditions

A detailed met ocean study was performed at the end of Feasibility to support Concept design work. This section provides a high level summary of the main findings. The full report is attached to the FDP for reference.

Locations of interest are approximately 75 km off the coast of Israel in deep water (approximately 1700 m). The locations of the Karish and Tanin sites are shown in Figure 7-21 relative to BMT's Mediterranean wind and wave hind cast grid.

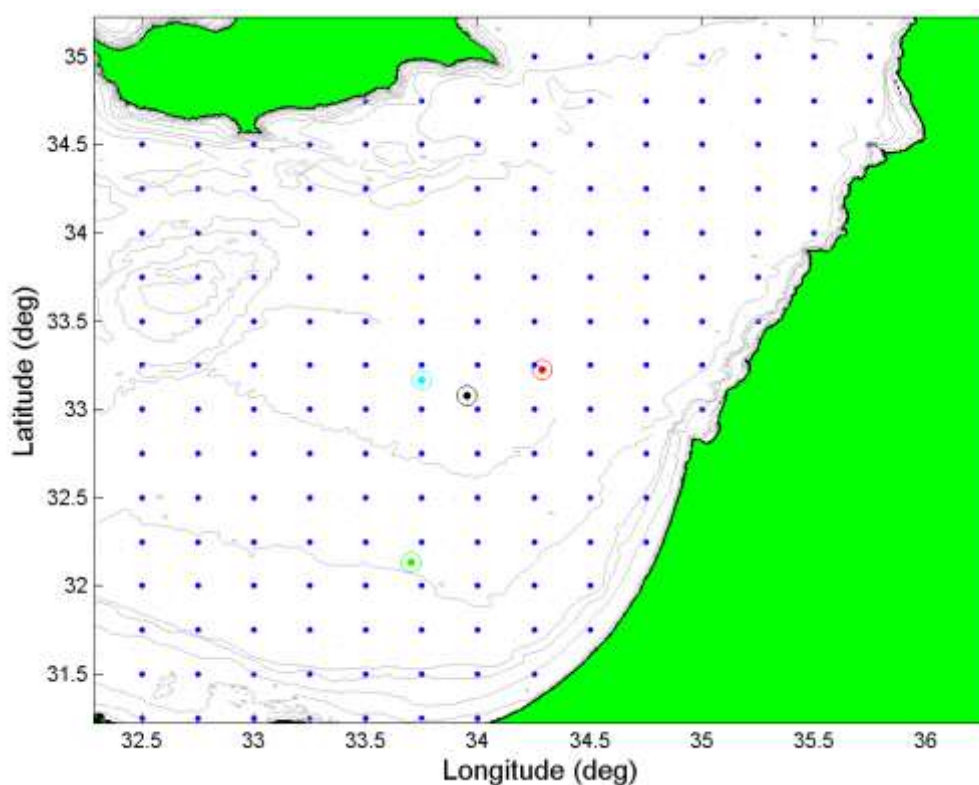


Figure 7-21 Met ocean data locations

Figure Notes:

- Karish location depicted by **red** marker
- Tanin location depicted by **cyan** marker
- The GOOS wave buoy site depicted by **green** marker
- The Tamar current site depicted by the **black** marker
- BMY Hind cast grid depicted by the **blue** dots

7.5.1.1 Statistical Data year round

Wave: Directional wave data at the Karish location is provided and analysed below.

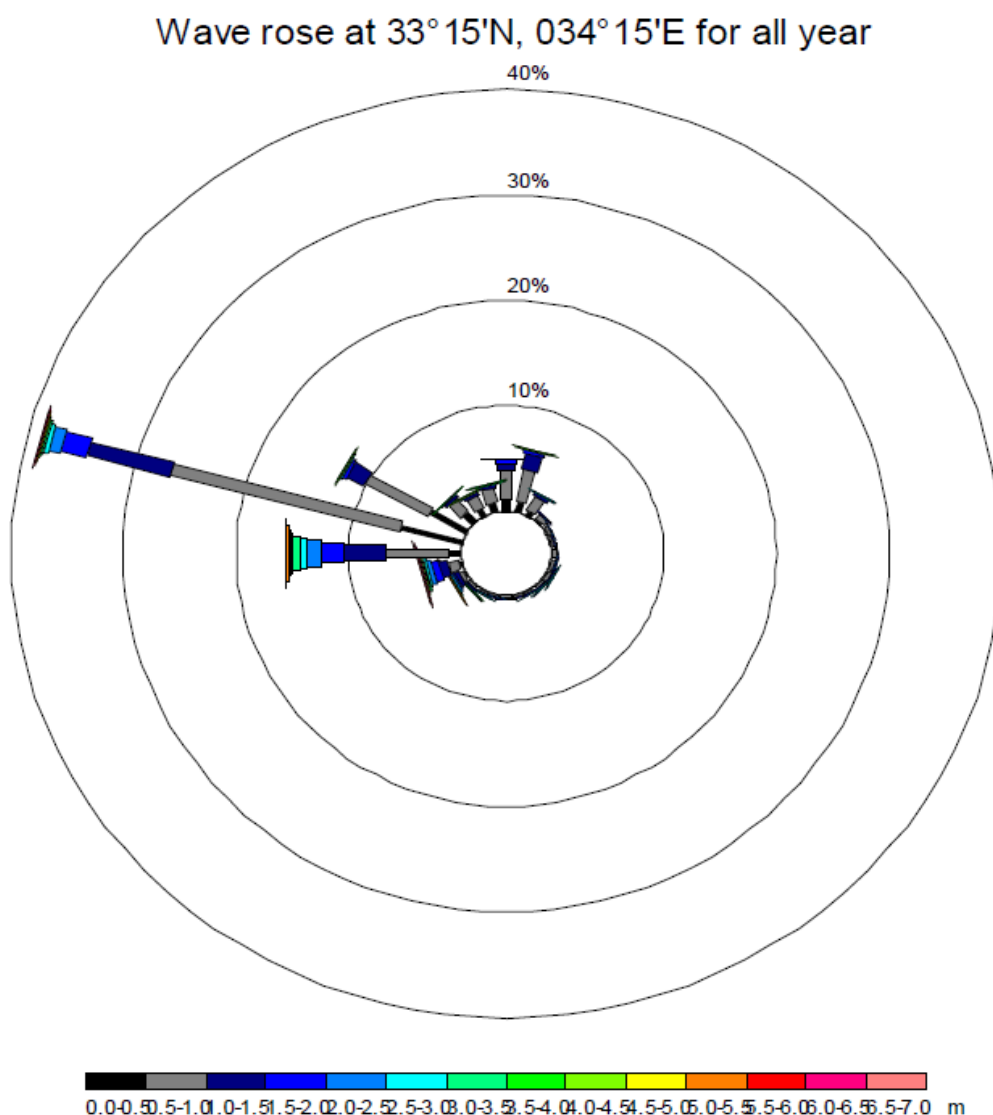


Figure 7-22 Wave rose at Karish FPSO

- ~85% of the year the waves are less than $H_s=1.5\text{m}$ which signals a very benign environment favorable for the FPSO spread moored design and the fatigue behavior of the LWSCR risers. The peak energy period of 90% of these waves is below 8s, much lower than the roll natural period of the FPSO.
- The dominant waves are from 285° almost 40% of the time. In general waves from the West / North West quadrant occur 70% of the year. Having a 270° boat heading will provide good sheltering on the portside laydown area which will have good accessibility and availability
- ~80% of the waves above $H_s=1.5\text{m}$ come from 270° +/-15° heading

Wind: Direction wind data for the Karish location are shown and analysed below.



Wind rose at 33° 15'N, 034° 15'E for all year

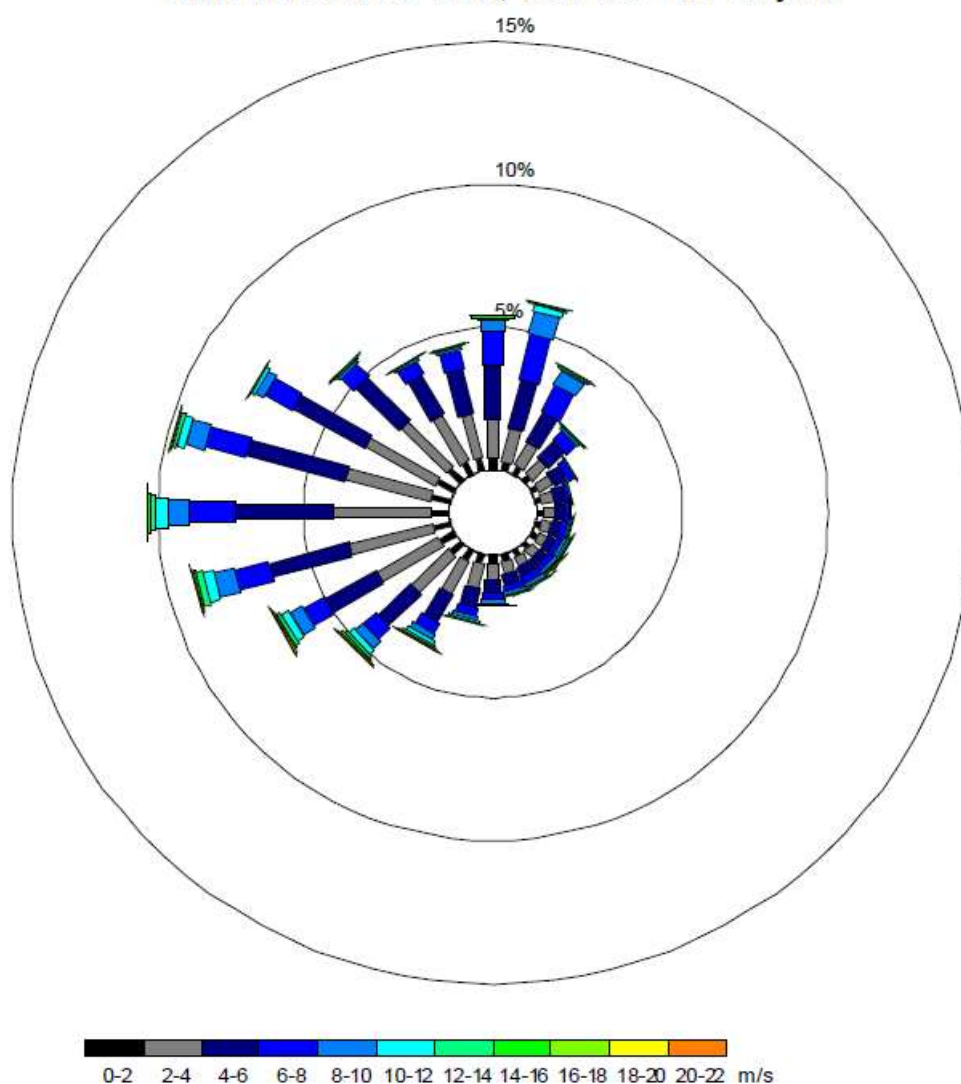


Figure 7-23 Wind rose at Karish FPSO for all year

- The wind rose is much more scattered compared to the wave rose. This shows that the effect of fetch is significant in this location, and that only the westerly winds and the North Eastern winds can raise significant waves.
- Winds from the South West / North West quadrant occur 75% of the year. This is a clear driver to put the helideck upwind to the Bow of the ship with the flare down wind. It also drives the optimal tender offloading operation with the moored FPSO upwind and the offloading hose to the stern of the ship

Current: Directional data for current and its analysis are provided below.



Total surface current rose at 33° 17'N, 034° 14'E for all year

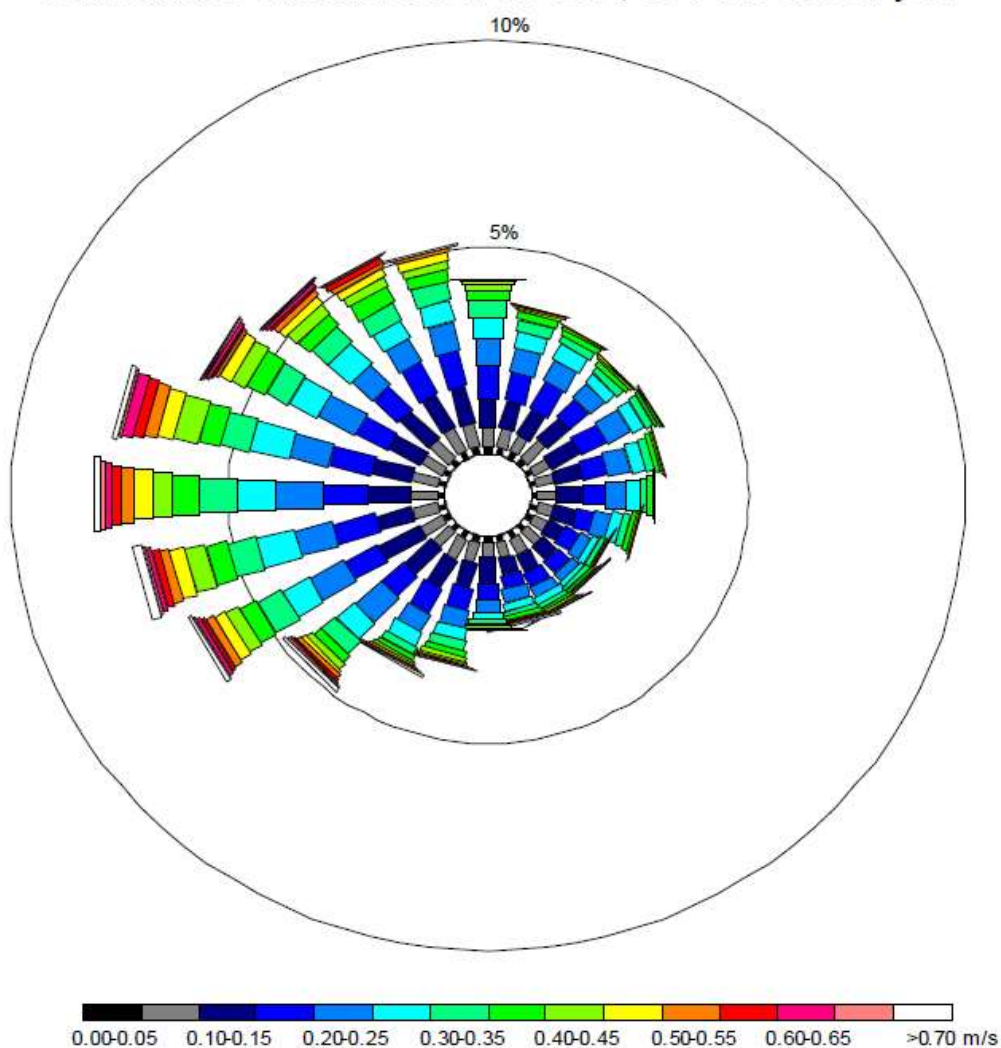


Figure 7-24 Current rose at Karish FPSO for all year

- Currents are very mild as expected in the Mediterranean, with surface current less than 0.5m/s 96% of the year. We do not anticipate vortex induced vibrations complications on the risers
- The current come from the South West / North West quadrant over 50% of the year which again strengthens the case for a tender operation located to the stern of the FPSO heading 270°

7.5.1.2 Extreme conditions

DNVGL-OS-E301 stipulates that the mooring system shall be analysed for the most unfavorable combinations of wind, wave and current with a return period of no less than 100 year and that a combination of wind and waves of 100 year return periods together with current with a 10 year return period is usually acceptable.

The directions of the extreme wind, wave and current are reasonably well correlated and the environmental loads can therefore be assumed collinear. The Ultimate Limit State (ULS) conditions are quite directional, with the highest waves (H_s m) coming from the West. The mooring spread would therefore need to be set with the FPSO heading to 270° to minimize roll motions and mooring offset in the largest sea state.

There is however a Northerly secondary direction of high waves ($H_s = 4.6$ m) and winds. With a mooring spread set with a 270° heading, this will expose the starboard side of the FPSO to beam seas

The longest wave periods coming from the North do not exceed 9.7 s, Easterly and Southerly environments are benign and Current speed is relatively mild (around 1 m/s).

Table 7-6: ULS conditions for permanent mooring at Karish

Direction from Relative to true North	100yr Waves		100yr Wind	10yr Current
	H_s [m]	T_{pmax} [s]	U_{wind} [m/s]	W_{0000m} [m/s]
0	4.6	9.5	18.9	0.7
15	4.8	9.7	19.6	0.64
30	2.7	7.1	18.2	0.62
45	1.9	6.0	16.6	0.63
60	1.9	6.0	12.2	0.58
75	1.9	6.0	12.7	0.61
90	1.9	6.0	12.9	0.63
105	2.7	7.1	16.9	0.63
120	3.1	7.6	19.4	0.58
135	2.6	7.0	18.6	0.65
150	2.5	6.8	17.6	0.73
165	2.4	6.6	16.5	0.85
180	2.1	6.3	18.6	0.66
195	2.5	6.8	19.3	0.72
210	4.0	9.4	19.8	0.72
225	5.3	10.9	23.5	0.9
240	6.1	11.6	23.7	0.94
255	7.2	13.0	21.6	1.04
270	7.7	13.4	21.7	1.03
285	7.2	13.1	20.9	1.03
300	5.7	11.7	20.1	0.85
315	5.1	11.1	19.0	0.88
330	4.8	10.8	18.6	0.87
345	4.1	9.0	18.6	0.79

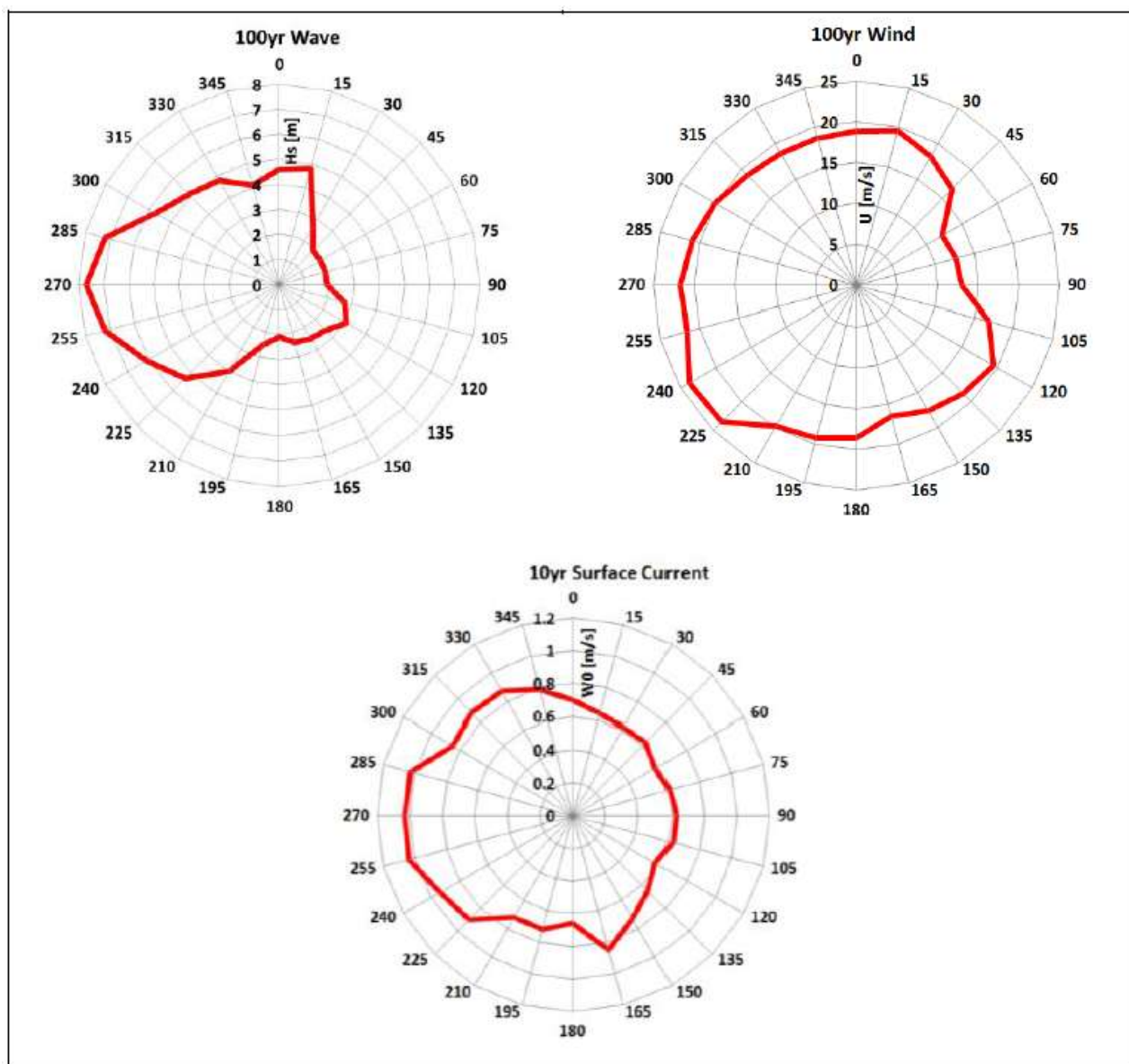


Figure 7-25 100 year Waves/Wind at Karish (Directions 'from')

The Karish 100 year extreme conditions in head and beam wind, waves and current have been compared to a similar (albeit larger) deep water spread-moored FPSO offshore Brazil. The below figure shows the extreme weather conditions are more severe at the Brazilian site and the beam conditions in particular are more severe than at Karish. Brazil and West Africa are the main analogues for spread moored FPSO's, with Brazil being the most challenging both in terms of weather and water depth.

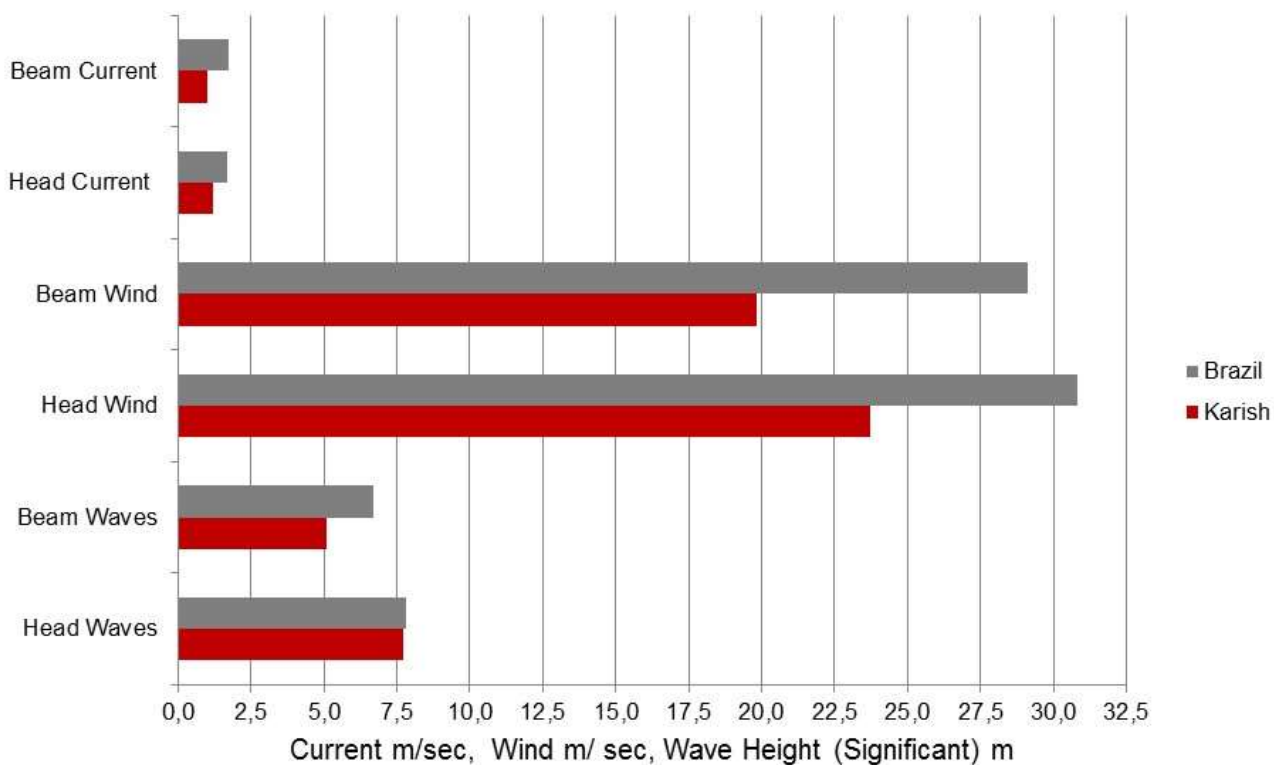


Figure 7-26 Comparison of 100 year return for spread moored FPSO: Karish vs Brazil

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7.5.2 Wells and Production manifold

Three clustered wells will be drilled in the Karish reservoir prior to start-up and will be tied back to a subsea manifold. A spare slot is provided to enable future tie-backs from, for example Karish North. See Figure 7-27.

Tanin wells will be drilled at a later date and tied-in to a second identical manifold located within the Tanin Lease area via rigid spools. It is probable that the Tanin wells will be drilled in multiple campaigns.

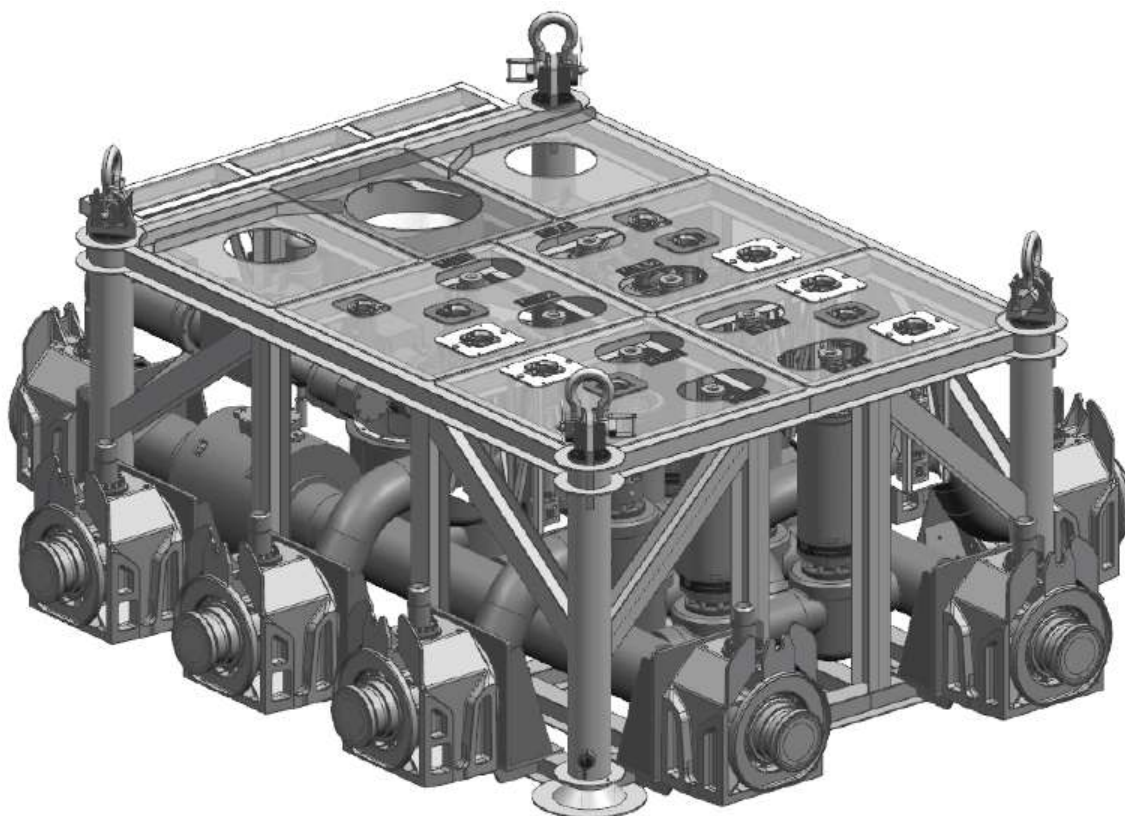


Figure 7-27 Karish and Tanin Subsea manifold module

The Karish and Tanin manifolds consist of a manifold module and a manifold foundation. The manifold foundation system is based on suction pile(s). However, depending on the soils information, a skirted mud mat may also be considered in the detailed engineering phase.

7.5.2.1 Manifold Functional Requirements

The functional requirements for the production manifold are summarised below:

- Manifolding of the wells to enable wells to be routed to either production line,
- Retrievable pigging loop enabling round trip pigging,
- Housing of umbilical termination and distribution for electrical power, electrical signals, hydraulic, chemical injection, and other,
- Housing of electro-hydraulic distribution which will provide an interface to a tree mounted SCM,
- Protection structure to protect only the manifold facilities from dropped objects.

The envisaged manifold pipework incorporating the functional requirements stated above is shown in Figure 7-28.

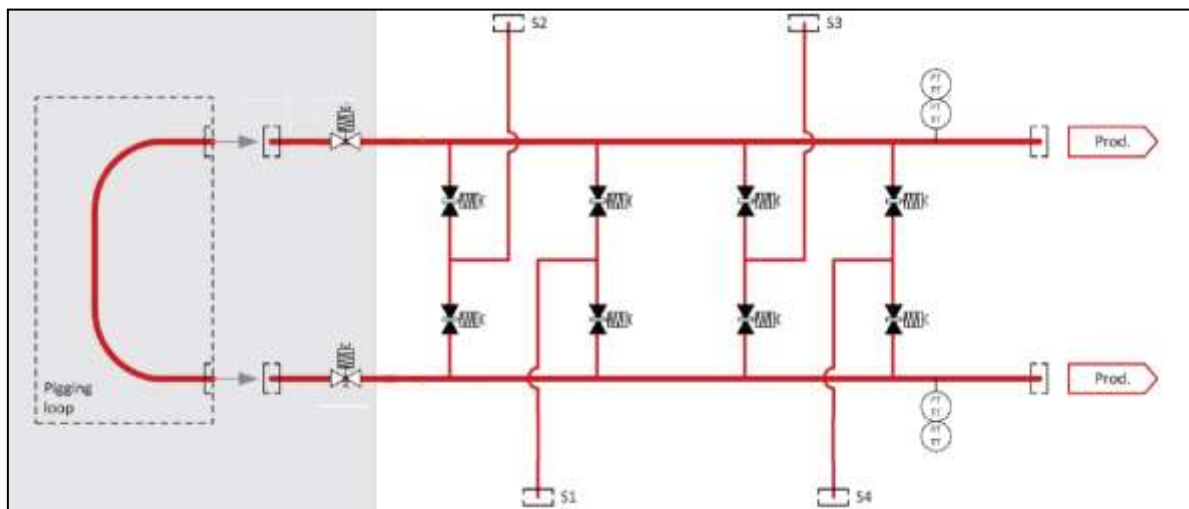


Figure 7-28 Karish and Tanin manifold module arrangement

7.5.2.2 Future Expansion

To allow additional flexibility for further expansion the external pig loop module has been designed as a removable structure: hence the 4-slot manifold could be enlarged to cater for additional well pairs drilled from the same location or at a remote position. The headers would be extended through short infield pipelines to a 2-slot manifold, the location of which could be confirmed at a future stage. The Phase I control system will make provision within the umbilical for extension of the controls for these two future wells. This future manifold will subsequently incorporate a pigging loop to provide round trip pigging facilities. This is shown schematically below.

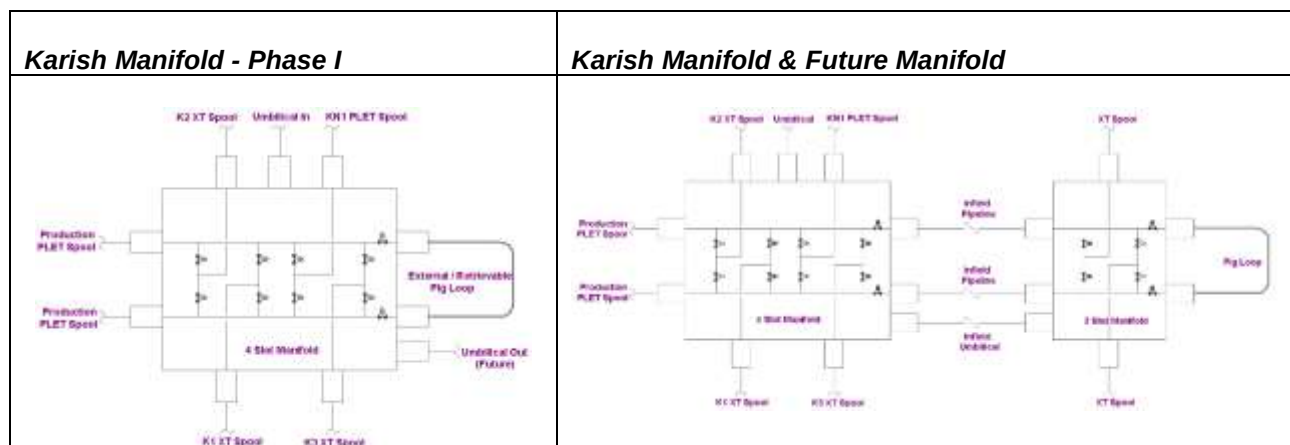


Figure 7-29 Future manifold expansion

The proposed tie-in system for the Karish and Tanin manifolds is the TechnipFMC horizontal UCON system.

7.5.2.3 Manifold Installation

The manifold has been envisaged as either a single or two lift structure, using the single point lifting method as follows:

- One lift for the manifold foundation;
- One lift for the manifold module.

Full details on manifold installation can be found within Section 9.1.4.

7.5.3 Production risers and Subsea Structures

Riser and umbilical quantities and primary design parameters for the production system are summarised below.

Table 7-7: Riser and umbilical provisions

LOCATION	PRODUCTION RISERS		UMBILICAL'S
	Nominal Size NB	Design/Shut-in Pressure	
Karish – Initial infield	2 x 10"	459 barg	1 Off
Tanin – Known Future infield	2 x 12"	509 barg	1 Off
Potential Future infield	4 x 10"	509 barg	2 Off
Gas Export Riser(s) – Initial phase	2 x 16" ^[1]	150 barg	1Off
Gas Export Riser(s) - Future	2 x 12"	150 barg	1 Off

Note [1]: Provisions will be made for installation and hook up of a second 16" future riser during phase 1 constructions works to enable increased gas throughput in the future.

The following riser types have been selected for the Karish and Tanin systems:

- Karish Infield Production Risers - dual 10" NB insulated Steel Lazy Wave Risers, (SLWR), each sized for a minimum of 400 mmscf/day
- Export Riser - Single 16" NB SLWR non insulated for Phase 1 (+ provision for 1 x additional 16" SLWR)
- Tanin Infield Production Risers for Phase 2: Dual 12" NB SLWR insulated risers. Final design to be completed during Tanin future detailed design work.

When the FPSO and mooring data are finalised, specific riser engineering and analysis will be conducted to confirm these recommendations and any possible opportunity to use an SCR configuration will be assessed as an alternative. SCR's would have a lower initial CAPEX than SLWR's.

An overview of the production facilities for Karish and the future Tanin development are illustrated below in Figure 7-30.

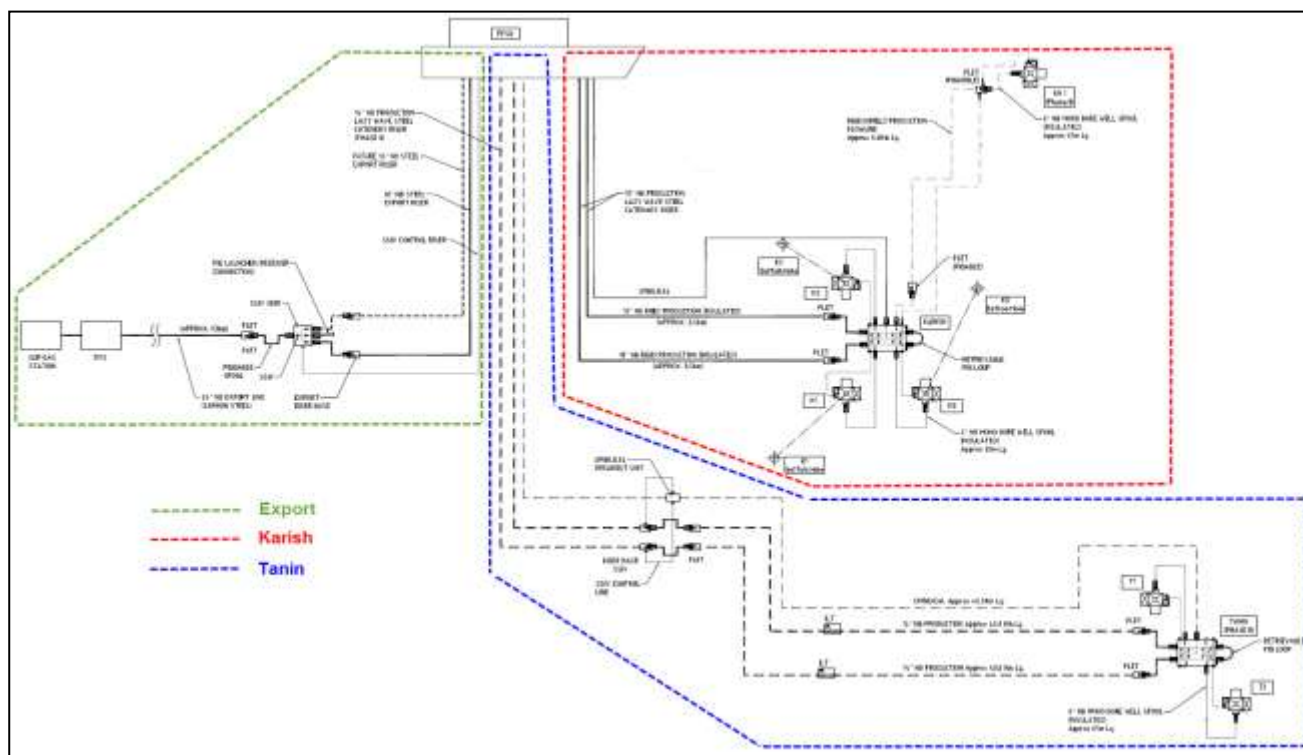


Figure 7-30 Production and export risers overview

7.5.3.1 Risers

The following arrangements will be included in the first development phase:

- 2 x Karish risers and 1x dry-gas riser will be fully installed and operational from day 1,
- Risers hang-offs and appropriate deck space will be provided for all future risers,
- Gas export pipeline SSIV control riser/umbilical will be installed.

7.5.3.2 Flowlines

The following arrangements will be included in the first development phase:

- 2 x 10" NB Karish insulated rigid production pipelines connected directly into the SLWR will be installed during the phase 1 construction works,
- All XT spools are 6" NB mono-bore, insulated for all Karish wells (KM-1, KM-2, KM-3).

7.5.3.3 Gas Export Risers and Subsea Isolation Valve (SSIV)

All production gas will be transferred to shore via a 24"/30" NB non-insulated rigid dry-gas pipeline which is connected to the FPSO via 1 x 16" NB SLWR (expandable to 2 x 16" NB SLWR's). The gas export line has an SSIV which will incorporate a hydraulically actuated valve or an NRV (subject to QRA during the Pre-FID engineering phase). The gas export SSIV will connect the gas export risers to the gas export pipeline and will have an extra connection hub for a pig launcher/receiver (PLR).

The dry-gas pipeline system is shown schematically in Figure 7-31 below.

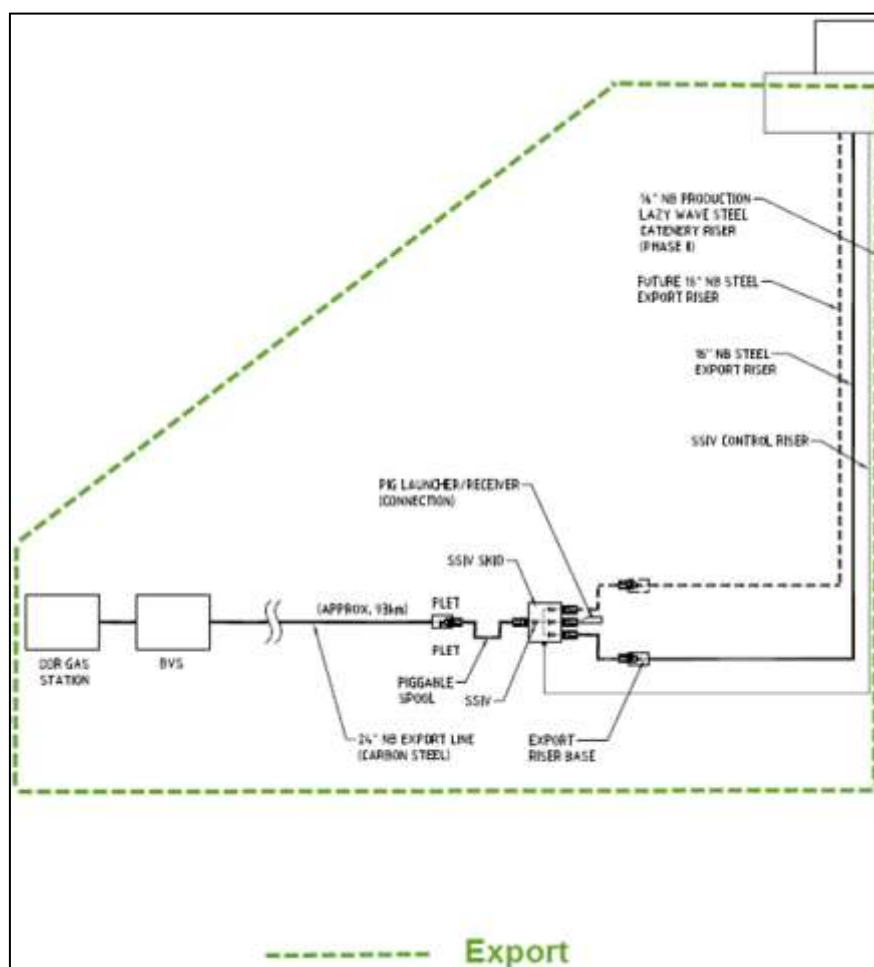


Figure 7-31 Production and gas export riser's overview

An SSIV is provided on the dry gas pipeline in order to isolate the FPSO from the gas export production system. The SSIV is assumed to be supported on a skirted mud mat, but a suction pile option may be considered depending on the soils data. There are no local or international codes that would make installation of an SSIV on the gas export line mandatory. The need for this device will be tested during the project QRA and ALARP process. Good oil field practice would normally require such a device on a pipeline with a 90km length. SSIV's are not required on the production risers as the gas volume between the riser bottom and the safety valves of the Xmas trees is minimal.

The gas export SSIV comprises the following main components:

- Gas export header,
- Hydraulically actuated isolation valve. (Note that a piggable non-return valve (NRV) may be considered, subject to QRA during pre-FID engineering),
- Pigging valve,
- Valves for the gas export riser branches,
- Control system & ROV interfaces,
- Pressure and temperature sensors.

The proposed tie-in system for the gas export SSIV is the horizontal Stabcon system. The structure will be installed by an installation vessel, using single point lift and lifting hooks in the corners of the structure fitted with ROV operable latches. Please refer to section 9.1.6 for further details.

7.5.3.4 Structures In-line with the Pipelines

Structures in-line with the pipeline are seabed-based and are generally supported on mud mats. However, if the foundation is required to accommodate a large horizontal load due to riser tension, this leads to a suction can solution due to the soft clayey soils expected in the field.

The subsea structures which are part of the subsea system for the Karish and Tanin fields' development are summarised below.

Table 7-8: Subsea structures preliminary weight summary

SUBSEA STRUCTURE		APPROX. WEIGHT (TONNES)	FOUNDATION TYPE
Karish	1 x Manifold	265	Suction Pile
	2 x PLETs	33	Mud mat
Karish North - KN1 (Future)	2 x PLETs	29	Mud mat
Tanin (Future)	1 x Manifold	265	Suction Pile
	4 x PLETs	33	Mud mat
	2 x RBS/SSIV	41	Mud mat
Gas Export	2 x RBS	43	Mud mat
	1 x SSIV/NRV	160	Mud mat
	1 x PLET	60	Mud mat

The size and weight constraints which are imposed by the installation vessel in relation to handling and installing pipeline appurtenances (e.g. a PLET structure) play a key role in whether or not a structure can be installed in-line.

7.5.3.5 Offshore Pipeline Design

Proposed pipeline routings are shown in Figure 7-32 below. It should be noted that final routing selection will be performed after completion of the geotechnical and geophysical survey campaign envisaged in Q2 2017.

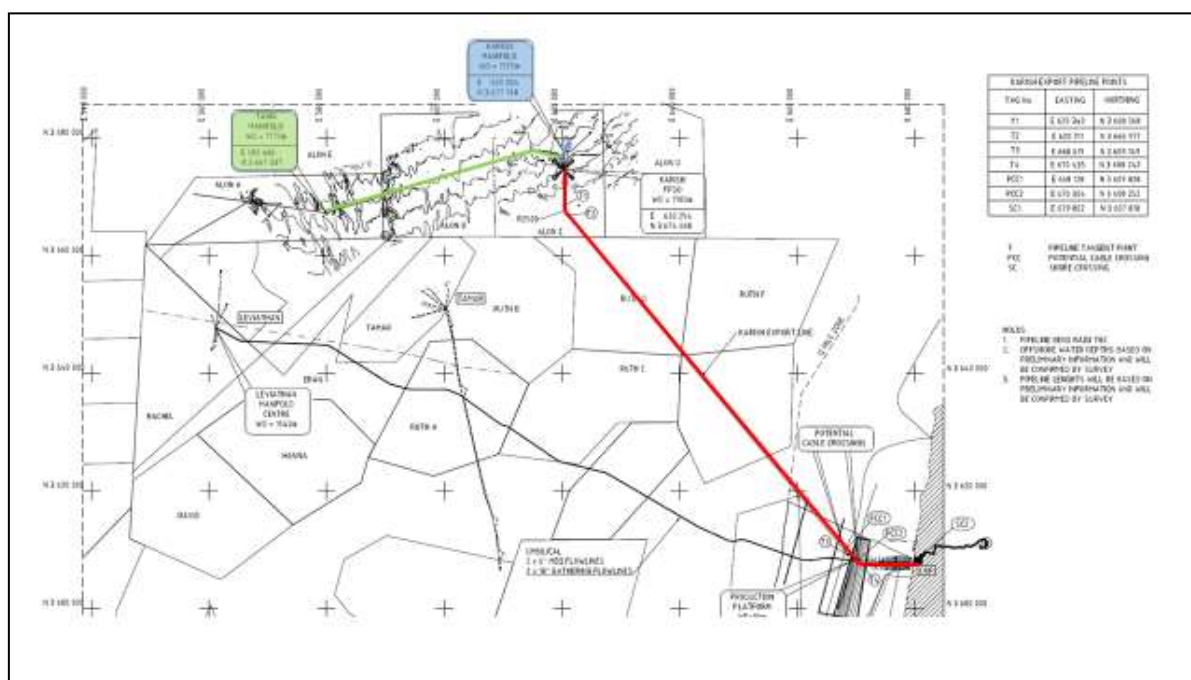


Figure 7-32 Offshore pipeline routing

The main features of the infield and export pipelines are summarised below.

Table 7-9: Infield and export pipeline summary

PARAMETER	EXPORT SYSTEM				KARISH PRODUCTION			TANIN PRODUCTION (FUTURE)		
	RISER	SECTION 1		SECTION 2	RISER	KN1	JUMPER	RISE R	PIPELINE	JUMPER
Nominal Pipe Size NPS	16"	24"/30"			10"	8"	6"	12"		6"
Outside Diameter (mm)	404.6	610.0			273.0	219.1	168.3	323.8		168.3
Design/Shut-in Pressure	150 barg				459 barg			509 barg		
Design Temp.	60/-20 °C				77/-20 °C			86/-20 °C		
Wall Thickness (mm)	25.4	25.4		33.3	28.6	18.3	15.9	33.3	25.4	18.3
Material	X65				X65			X65	X65	
Manufacturing Method	SMLS	SAWL			SMLS			SMLS		
Coating	3mm 3LPE	3mm 3LPE or 0.3mm FBE + CWC	3mm 3LPE		80mm 5LPP		90mm 5LPP	3mm 3LPP		
Length (km)	5	16.5	25.5	50	2x 5	5	N/A	2x 5	2x 40	N/A

All infield pipelines are highly prone to lateral buckling due to the high pressure and high temperature service requirements. Lateral buckling analyses will be performed to assess the criticality of pipeline post-buckling configuration and requirement for mitigation measures during the pre-FID engineering phase. The export pipeline system lateral buckling propensity is considered low risk.

Due to the planning and building regulatory framework in the Dor area, the export pipeline will be trenched and buried in the shallow section of the route, up to a water depth of 60m LAT. Burial depth requirements dictate the final depth of cover to be 1.2m ToP.

The concrete coating on the gas export line will be optimised in the shallow water section as summarised below

Table 7-10: Dry gas 24"/30" pipeline concrete coating requirement summary

PARAMETER	EXPORT PIPELINE SECTION 1 (25.4MM WT)					
Water Depth Range in metres (LAT)	0 to 20	20 to 32	32 to 60	60 to 94	94 to 120	120 to 440
Length (km)	1	1.9	6.2	3.2	1.9	4.2
Thickness (mm)	None HDD	90	60	160	90	40

It is believed that there will be at least three (3) telecommunication cable crossings on the export pipeline route as shown below (Figure 7-33). These crossings are with cables operated by Med Nautilus IL and IC1. The final number of crossings will be determined during the offshore geophysical and geotechnical survey campaign envisaged during Q2 of 2017.



Figure 7-33 envisaged cable crossings

7.5.4 Sub-sea control systems including umbilical

7.5.4.1 Wellhead and Downhole Measurements

The provision of wellhead pressure and temperature gauges downhole and within the subsea tree is provided as standard. Pressure and temperature gauges are provided upstream and downstream of the production choke valve. An upstream sensor will be located upstream of the wing valve and will provide data regarding the shut-in conditions of the well. The gauge set downstream of the choke provides flowline operating conditions and a monitor for operating temperatures. The temperature monitoring is for the control of hydrates and confirming material status where extreme low temperatures resulting from the Joule-Thomson effect of gas expansion through the choke are experienced.

Flow measurement will be required for reservoir management purposes to establish the performance of the well overall and with respect to each phase: hydrocarbon liquids, gas and water.

Pressure build-up tests will be carried out with the pressure gauges provided on the subsea tree. Provision for downhole pressure and temperature (DHPT) measurements is provided for pressure build up tests closer to the well completion into the reservoir. All the information from the gauges will be communicated back to the host facility via the subsea control system. For pressure build up tests a “fast scan” facility within the control system will be specified to enable the gauges to be read rapidly and thus allow the variation of condition over short time spans be recorded to map the reservoir performance at the required accuracy.

An ultrasonic sand detection system is provided. Sand detectors are to be installed on each production Xmas tree.

Subsea Wet gas flow meters (WGFMs) are provided for each well. Flow metering accuracy (per phase) will depend upon the proportion of that phase to the total (as a percentage). Typically, all phases can be measured to within an uncertainty of less than 10% and ideally between ± 2 and 5%. When the percentage of one phase is less than 10% of the volumetric throughput, the uncertainty of measurement of that phase will slip towards the 10% level.

Operational flow control will be a function of the findings of the reservoir testing/management philosophy (see Section 0) together with the requirements of the production process facility. Operational flow control will also be employed, where possible, to optimise the flow regime within the pipeline system to minimise flow assurance risks. Pressure/flow control will be achieved with topsides chokes and trimming of flow between

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wells at subsea chokes. It is currently envisaged that fiscal metering will be topside on the FPSO due to the need for the delivery point to be at the interface with the INGL facilities (10 km from the Dor coast).

Subsea choking at the well allows for trimming flow between wells and to control draw down at the completion should it be required to lower the differential pressure at the completion and limit water coning/sand production.

7.5.4.2 Subsea Control System

The overall purpose of the control system is to safely control, monitor and operate the complete subsea facilities comprising the production wells, production manifold and associated equipment, from the FPSO. These requirements are summarised below:

- Operation of all actuated valves in the subsea production facilities,
- Operation of downhole safety valves (DHSV) installed in each production well,
- Monitoring of production well pressure and temperature (downhole and at XT),
- Inferred monitoring of actuated valve position for all actuated valves in the subsea production facilities,
- Generation of subsea alarms on detection of out of limit system parameters,
- Interlocks and inhibits to prevent incorrect subsea valve operating sequences,
- Initiate automatic subsea shutdown sequences via trips from the ESD system,
- Initiation of operations inhibits on loss of permissive signals from FPSO DCS and safety systems,
- The control system shall be “safe” following a shutdown with the status of all valves known,
- Workover and system maintenance inhibits,
- Start-up overrides and shutdown reset facilities,
- Remote position indicators incorporated on all FAI choke valves and actuated pigging valves,
- Redundant pressure and temperature sensors shall be placed upstream and downstream of the subsea production choke valves,
- Downhole pressure and temperature sensors shall be installed in all production wells.

To achieve these objectives, the control system is designed in accordance with the following design principles:

7.5.4.2.1 Karish Development

The main features for the Karish Development system are:

- Conventional electro-hydraulic multiplex system with electrically actuated chokes and manifold header valves,
- Allowance for expansion to accommodate Tanin in a later phase,
- Communication between the host FPSO and the SPS by direct physical connection for both electrical and hydraulic circuits,
- Simple SPCS designed as far as possible on proven subsea control system principles and hardware, with minimum requirement for intervention, maintenance or inspection,
- Minimise common mode failures and be flexible and allow for future expansion of the system,
- Application of redundancy to provide high availability and reliability while minimising system cost and complexity,
- SPCS to be fault tolerant to extend the maintenance interval,
- SPCS to be fail safe on loss of hydraulic supply pressure and/or loss of electrical power and/or communication by bleeding off the hydraulic pressure at the surface HPU,
- Shutdown signals to be hard wired on the FPSO to the SCU computers. Connected directly to the surface HPU in order to vent hydraulic supplies whenever required by the shutdown logic,
- Operator interface by means of Operator Stations, keyboards and video display unit (VDU) screen(s) connected to the DCS on host facility,
- Subsea components designed for continuous service at the design water depth,
- All subsea components of the control system, including hydraulic and electrical distribution modules, to be retrievable, either individually or as part of sub-assemblies,

- The topside Hydraulic Power Unit to have an off-line filtration system to maintain the required fluid cleanliness level in the hydraulic reservoir for the subsea equipment most sensitive to contamination such as solenoid valves and hydraulic control valves,
- Consideration of all the actuator operating pressure ranges, to ensure that the opening (or closing) of any valve on the circuit shall not initiate any movement of any of the other valves,
- Opening and closing speed of valves under operating conditions are maintained within the design limits of valves and actuators,
- Design of the subsea electronic system to minimise power consumption.

7.5.4.2.2 Control System Description

Control and monitoring of the subsea system is performed by Subsea Control Modules (SCM's). The SCMs are supplied with hydraulic power for fail safe valve operations and to direct the hydraulic power in accordance with instructions received from the MCS via the SPCU, TUTU, umbilical, SUTU, and subsea distribution network.

The MCS displays the status of the X-mas trees, wells and Manifolds via their SCM's at the Operator Work Stations. It also displays the status of other system equipment together with closely associated vessel equipment (HPU, SPCU, and ESD system).

The MCS enables topside operators to control the X-mas trees, wells and Manifolds via the Operator Stations by relaying control messages from the Operator Stations to the SCM's, which then perform the actual control.

The HPU is controlled and monitored locally or from the MCS but is also connected directly to the FPSO ESD system. Output pressure from topside HPU is:

- LP: Design Working Pressure: 207 barg
- HP: Design Working Pressure: 690 barg

Note: Pressures are typical and subject to confirmation.

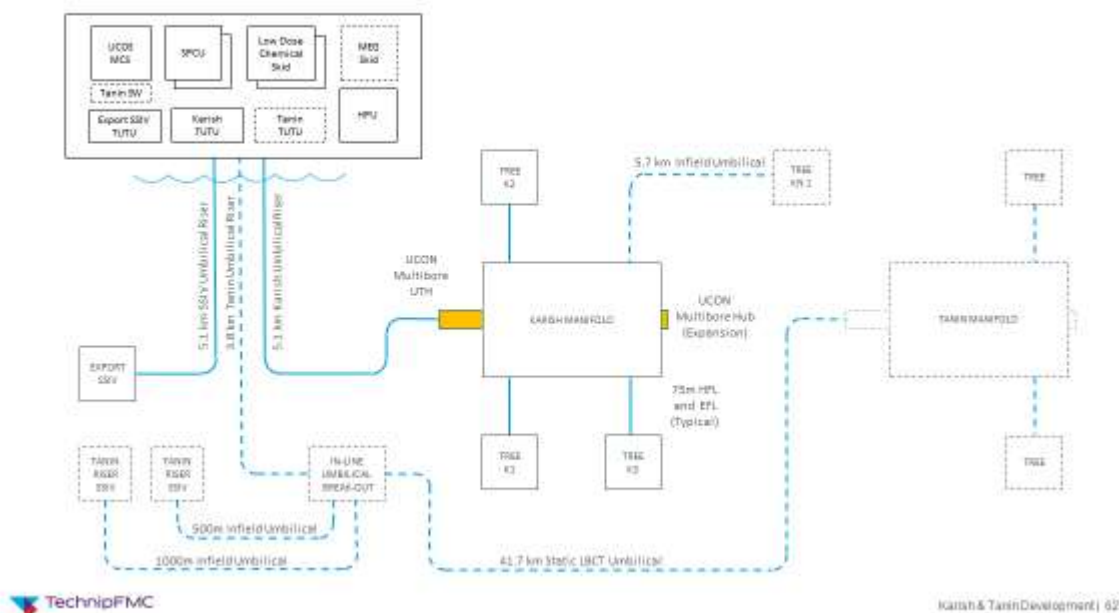
SCU, SPCU and HPU are sized to cater for ten subsea production wells in total. It is currently envisaged that the system will be sized for the Phase 1 and Phase 2 requirements from Day 1, however this will be confirmed during the pre-FID engineering phase. The above requires limited pre-investment for the future phases, but will greatly simplify requirements for any future expansion.

Table 7-11: Control system capacity

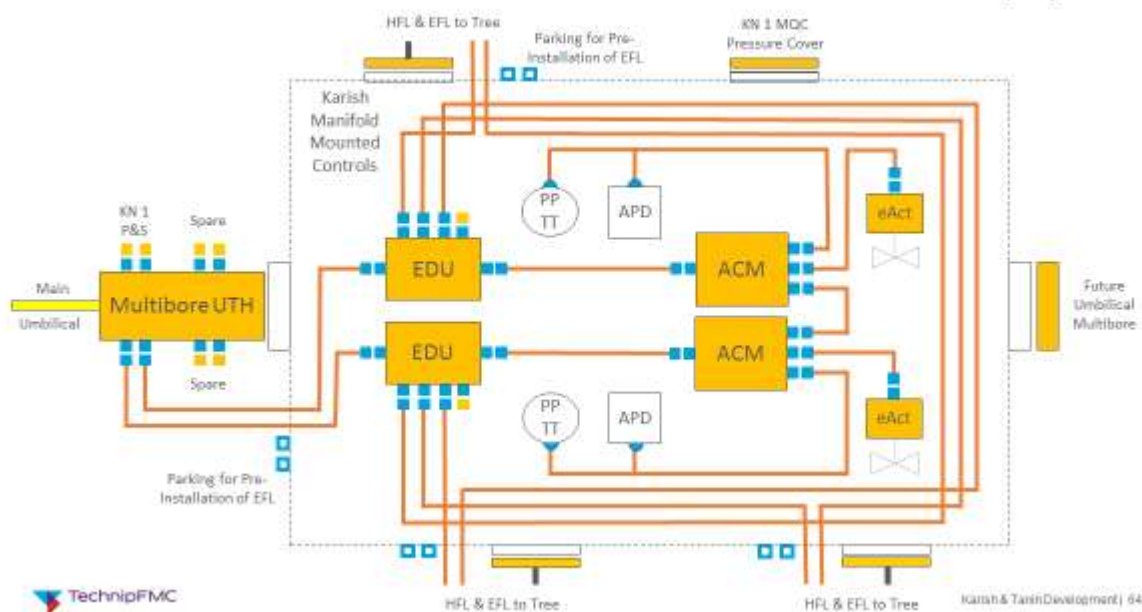
FIELD	PHASE 1		PHASE 2	
	WELL COUNT	EXPANSION	WELL COUNT	EXPANSION
Karish	3	1		
Karish North			1	1
Tanin			2	2
TOTAL	SPCS Design Capacity = 10 Wells			

Below is a series of diagram showing where the key control functionalities are located and how they interact. Focus is on the Karish system for illustrative purposes, but the Tanin system is very similar.

Controls & Umbilicals – Distribution Overview



Controls & Umbilicals – Karish Manifold Mounted Equipment



Controls & Umbilicals – Karish Tree Mounted Equipment

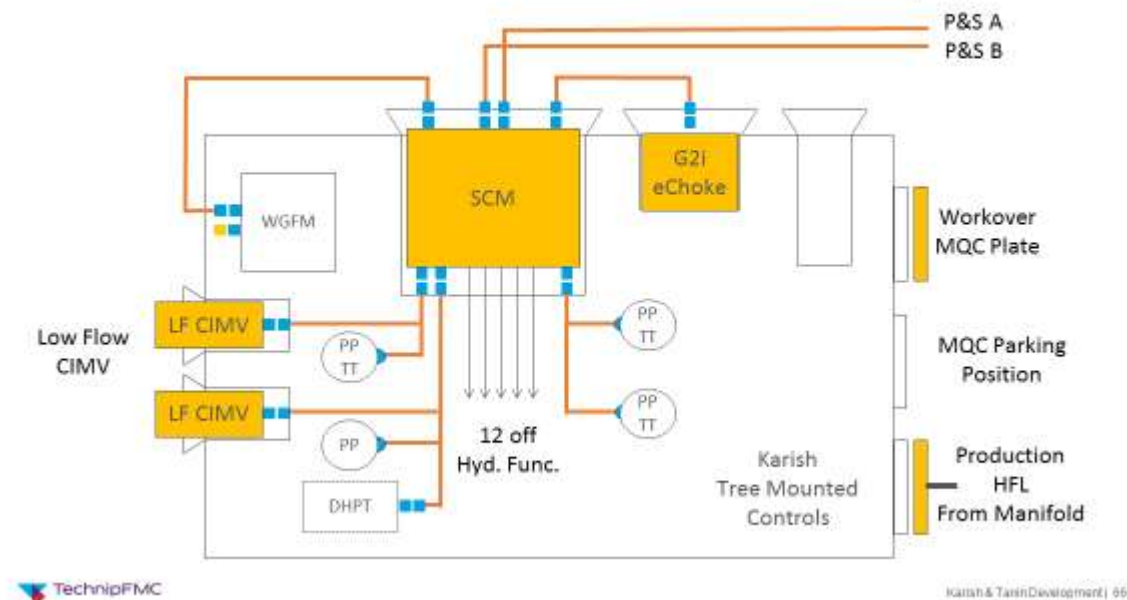


Figure 7-34 Subsea production system - Control System Diagrams

7.5.4.2.3 Umbilical cable specification

The umbilical system is designed to comply with the requirements of the control system with respect to performance and functionality. The umbilical system is to be designed for operation without maintenance for 25 years. The umbilical system shall connect the subsea production control system to the FPSO and supply the Karish and Tanin field with hydraulic power, chemical services, and electrical power and signal.

The umbilical system provides the following:

- Redundant supply for LP and HP hydraulic lines and electrical cables,
- Chemical injection lines (no redundancy, but a spare line will be included),
- Spare lines will also be included for one universal hydraulic supply and one electrical cable,
- All spare lines shall be terminated at the manifold located UTU.

Overall System Description

The umbilical and distribution system for the Karish & Tanin development shall consist of the following items:

Table 7-12: Umbilical system description

KARISH DRILL CENTRE (PHASE 1 DEVELOPMENT)	TANIN DRILL CENTRE (PHASE 2 DEVELOPMENT)
Karish Main Umbilical	Tanin Main Umbilical
Export SSIV Umbilical	Tanin Production SSIV Static Umbilical / Flying Lead
Hydraulic Flying Leads	KN1 Well Infield Umbilical
Electrical Flying Leads	Hydraulic Flying Leads
	Electrical Flying Leads

Karish Main Umbilical

The preliminary Karish umbilical cross section consists of the following functional elements and is to be confirmed during FEED:

Table 7-13: Karish development - main umbilical functional elements

NO.OFF	RATING	DIMENSION (ID)	FUNCTION
2	207 bar	12.7mm	LP supply
2	690 bar	9.5mm	HP supply
1	690 bar	25.4mm	Vent Line
2	690 bar	25.4mm	Methanol
1	345 bar	12.7mm	Chemical 1
1	345 bar	12.7mm	Chemical 2
1	345 bar	12.7mm	Chemical spare
4	0.6/1.0 kV	6 mm2	Electrical quad

The Karish umbilical system is relatively short at around 4km. A hybrid umbilical construction is proposed. In the hybrid umbilical, the Methanol line may be a single larger bore steel tube, around which smaller diameter thermoplastic hoses are arranged

The Karish field main umbilical will be a transition type construction with dynamic and static sections in a single continuous construction.

Termination at the subsea end shall be by collet type horizontal multibore connection based on a standard UCON design, see Figure 7-35. It is currently envisaged that buoyancy modules shall be included to configure the riser section of the Karish main umbilical in a lazy wave, however the use of free hanging umbilical risers shall be investigated in further detail during the pre-FID engineering phase.



Figure 7-35 UCON type UTH

Karish Drill Centre Distribution

Distribution of hydraulic supplies and chemical services will be by small bore tubing integrated within the Karish manifold, terminating to inboard MQC plates located adjacent to each of the manifold branch hubs. With the exception of the KN-1 well, hydraulic supply and chemical distribution to trees shall be by thermoplastic (TP) flying leads.

Distribution of electrical power and signal to the manifold and close clustered wells (KM-1, KM-2 and KM-3) will be by flying leads from the UTH mounted electrical wet mate connectors, to separate channel A and channel B electrical distribution units (EDU) located on the manifold.

The EDUs are assembled from industry standard “spider box” type PBOFH distribution harnesses, protected by a free flooding steel structure. The EDU is designed for, and shall be located on the manifold for ease of retrievability and replacement.

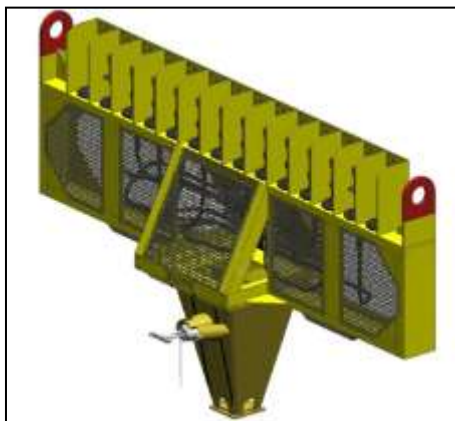


Figure 7-36 Retrievable EDU

In the unlikely event of failure of one power and communication channel, the electrical distribution system, or parts thereof, can be isolated, recovered, and replaced without affecting production. Close clustered Karish wells (KM-1, KM-2 and KM-3) may have separate EFLs running from the EDUs to the tree mounted SCMs. Distribution of hydraulic supplies, chemical services, and electrical power and signal to the KN-1 satellite well shall be via an infield umbilical. The KN-1 umbilical may be of hybrid construction, utilising steel tube cores for Methanol transportation, and thermoplastic hoses for hydraulic supply and low dose chemical services.

The infield umbilical shall include electrical cables which shall be terminated with field assembly cable terminations (FACT) which have pressure balanced oil filled hose (PBOFH) tails connected to ROV operable, bulkhead mounted electrical connectors at the cobra-head type UTH to be found at each end of the infield umbilical. Connection between the main umbilical power and signal and the infield umbilical power and signal is by electrical flying leads directly from the main umbilical horizontal multibore termination, to the cobra-head type infield umbilical without passing through the EDUs.

The preliminary umbilical requirements for KN-1 are summarised below and are to be confirmed during FEED.

Table 7-14: Karish North infield umbilical functional elements

NO.OFF	RATING	DIMENSION (ID)	FUNCTION
2	207 bar	12.7mm	LP supply
2	690 bar	9.5mm	HP supply
1	690 bar	25.4mm	MEG/Methanol
1	345 bar	12.7mm	Chemical 1
1	345 bar	12.7mm	Chemical 2
2	0.6/1.0 kV	10 mm ²	Electrical pair

Tanin Umbilical System

The Tanin umbilical system will be fully defined as the requirements for the Tanin development evolves. The preliminary requirements are summarized in Table 7-15:

Table 7-15: Tanin dynamic umbilical section functional elements

NO.OFF	RATING	DIMENSION (ID)	FUNCTION
2	207 bar	12.7mm	LP supply
2	690 bar	9.5mm	HP supply
8	690 bar	38.1mm	MEG ⁽¹⁾
1	345 bar	12.7mm	Chemical 1
1	345 bar	12.7mm	Chemical 2
1	345 bar	12.7mm	Chemical spare
3	0.6/1.0 kV	16 mm ²	Electrical quad
2	207 bar	9.5mm	SSIV direct hydraulic control
2	0.6/1.0 kV	6 mm ²	7 Way SSIV instrument cable

Note: (1) requirement for MEG would be significantly reduced if a DEH hydrate management strategy for the Tanin wells is applied as currently envisaged. Once confirmed during the next design phase this specification will be updated. The MEG core would be used for Methanol.

Tanin umbilical system may be constructed for installation as a continuous operation for both static and dynamic sections. Both umbilical sections may be joined at an inline transition and distribution structure. The umbilical inline structure has a gravity base which is connected to the umbilical transition and distribution box by a pair of trunnions to facilitate deck handling and installation. A locking device which is manual or ROV operable is also fitted.

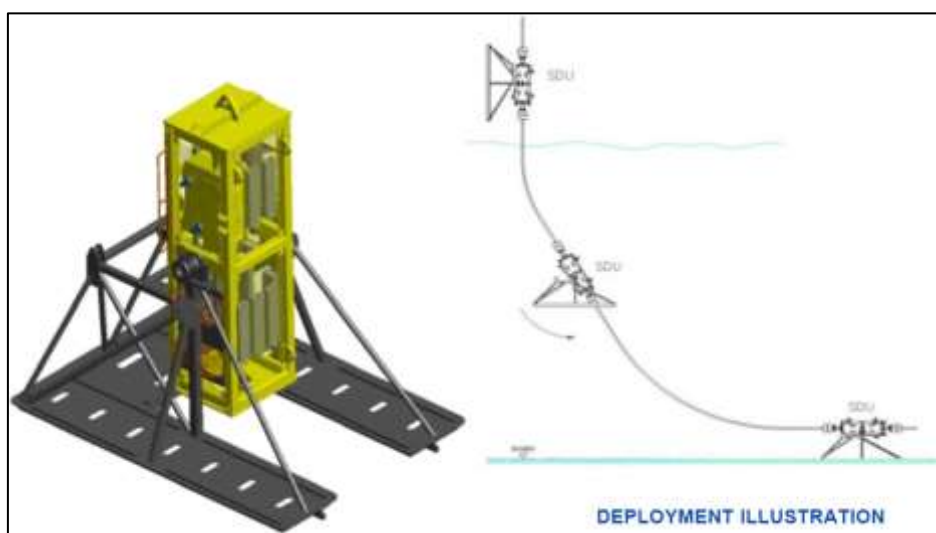


Figure 7-37 Inline umbilical break out

The preliminary static umbilical requirements for Tanin are summarized in

Table 7-16 and are to be confirmed during FEED:

Table 7-16: Tanin static umbilical section functional elements

NO.OFF	RATING	DIMENSION (ID)	FUNCTION
2	207 bar	12.7mm	LP supply
2	690 bar	9.5mm	HP supply
1	690 bar	4" ID	MEG ⁽¹⁾
1	345 bar	12.7mm	Chemical 1
1	345 bar	12.7mm	Chemical 2
1	345 bar	12.7mm	Chemical spare
3	0.6/1.0 kV	16 mm2	Electrical quad

Note: (1) requirement for MEG will be significantly reduced if a DEH hydrate management strategy for the Tanin wells is employed as currently envisaged. In this case this specification would be revised.

7.5.5 FPSO Hull and mooring systems

7.5.5.1 Overview

The Karish FPSO is designed to be moored 75 km off the coast of Israel. The FPSO hull shall be new-build with double side and double bottom, with a typical offloading parcel size of 350,000 to 450,000 bbls. The tanks shall be loaded to a maximum of 95%. The hull shall be designed for a total tank storage capacity 1,000,000 bbls including cargo and excluding slops.

The FPSO shall have flat panel sides but shaped forward and aft to minimize mooring forces and roll motion. Skegs will be installed aft of the FPSO to reduce vanning during towing to the field.

The FPSO shall be spread moored and shall be fitted with one riser balcony on port side and one balcony for gas export on the starboard side. A bilge keel shall be fitted on both sides. Fatigue life and hull corrosion criteria used during the design shall comply with DNV-GL class requirements to allow continuous offshore operation during its operational lifetime with no dry-docking.

The FPSO shall be arranged for in-water surveys accordingly and shall be fitted with facilities that enable any maintenance required during the operational lifetime as well as the surveys required by DNV-GL, Port Administration or Flag Statutory requirements without affecting the production/ processing capacity of the FPSO.

The FPSO shall be designed with a 72 POB Living quarter (to be confirmed during the next design phase as Security requirement and Operational manning requirements are further matured), situated forward with a helideck on top.

The Karish FPSO design shall have focus on HSE, considering safe operations and minimizing the environmental footprint as far as possible. The FPSO shall be designed to minimise harmful discharges, and equipped for handling and processing of all waste liquids and materials on board to minimize the requirements for transportation for onshore handling. This applies for production, machinery, living quarter and other waste from the FPSO.

The hull shall be designed for 15,000 tonne topside weight with centre of gravity 10 m above main deck. Layout drawings generated during FEED work are provided below.

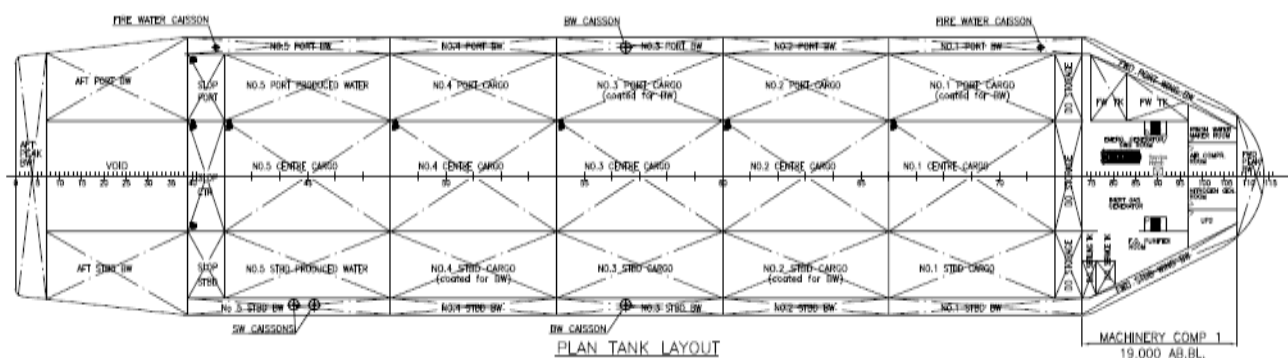


Figure 7-38 FPSO tank layout

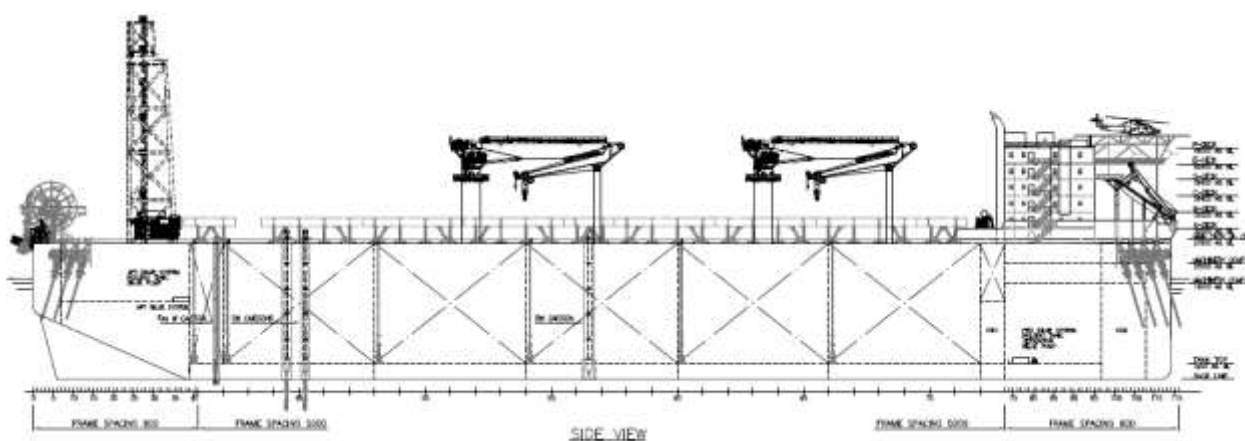


Figure 7-39 FPSO hull side view

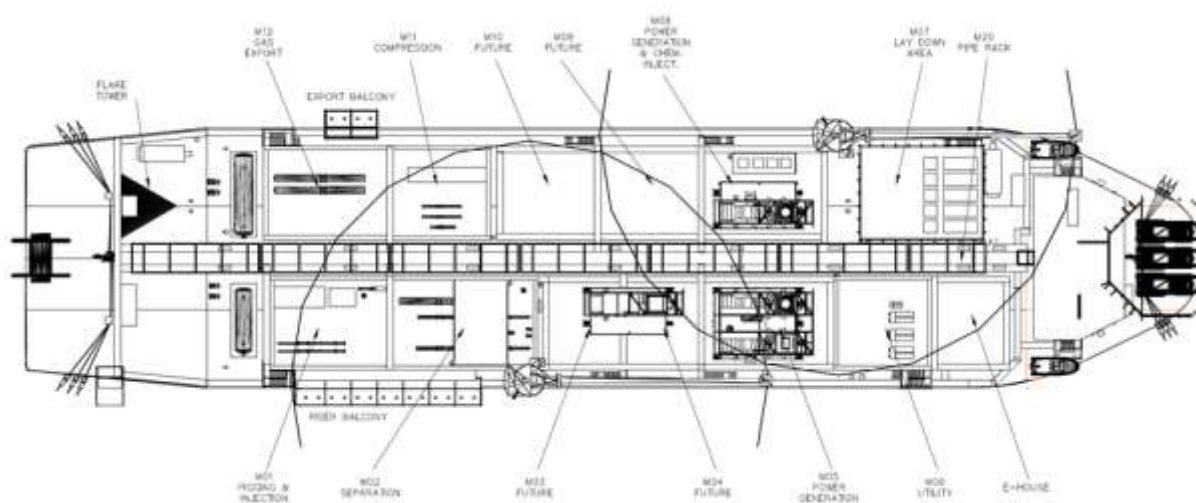


Figure 7-40 FPSO process deck preliminary arrangement

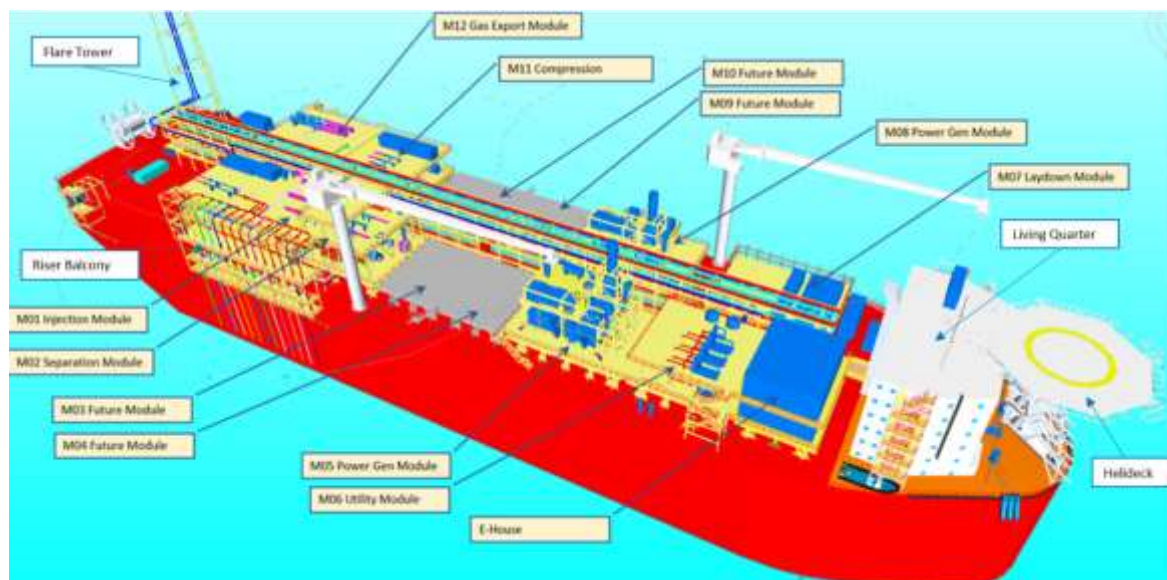


Figure 7-41 FPSO 3D model screen shot

Table 7-17: Main characteristics of Karish FPSO hull

HULL MAIN CHARACTERISTICS

Dimensions	
Length overall	227,0 m
Breadth molded	50,0 m
Depth molded	27,0 m
Design draft	20,0 m
Cb	0,94
Living quarter capacity	72 POB

Capacities	
Cargo capacity @ 98% excl. slop tank	160 000 m ³ (1.000 000 barrels)
Topside capacity	15 000 t
Produced Water Tank	16 590 m ³
Slop Tank capacity	6 810 m ³
Ballast capacity	70 000 m ³
Fuel oil storage capacity	2 300 m ³
Fresh water storage capacity	800 m ³

Tank Arrangement (Cargo & ballast)	
Cargo Tanks	No. 1 Port, Centre, Starboard No. 2 Port, Centre, Starboard No. 3 Port, Centre, Starboard No. 4 Port, Centre, Starboard No. 5 Centre
Produced Water from Topside Process	No. 5 Starboard No. 5 Port
Ballast Water Tanks	Fore peak Forward tank wing Port Forward tank wing Starboard No. 1 Wing tank Port, Starboard No. 2 Wing tank Port, Starboard No. 3 Wing tank Port, Starboard No. 4 Wing tank Port, Starboard No. 5 Wing tank Port, Starboard Aft Wing tank Port Aft Wing tank Starboard Aft Peak
MGO Storage Tank	Centre, Port and Starboard (Forward of Cargo Tank No.1)
MGO Service Tank	Starboard Side (Machinery Comp.)
MGO Settling Tank	Starboard Side (Machinery Comp.)
Fresh Water Storage Tanks	Port side (Machinery Comp.)
Slop tanks	Port (Aft of Tank No. 5) Centre (Aft of Tank No. 5) Starboard (Aft of Tank No. 5)

The FPSO hull includes storage capability for bulks, including diesel fuel, potable water, Rich and Lean MEG and methanol. The FPSO marine systems do not include sea chests, but will include sea water caissons for the sea water and fire water systems. To ensure watertight and structural integrity within the hull, these caisson penetrations shall be routed vertically through water ballast tanks. Water for filling ballast tanks shall come from a branched line from the sea water system overboard to provide efficiency, in addition to the primary water ballast system pumps. The hull shall include suitable provisions for ventilation and dry access to all primary structures for inspection as per Class requirements. Use of small remote ROV's shall be utilised for underwater inspection, in addition to water ballast tanks.

7.5.5.2 Classification Society

The FPSO, including the hull, topsides, machinery, equipment and outfitting, shall be constructed in accordance with the Rules and Regulations and under the survey of Det Norske Veritas GL (DNV GL, the

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"Classification Society"), and shall be distinguished in the register according to DNV Offshore Codes, Classification of Offshore Units by the symbols of following main class: -

- Oil, Ship shaped Oil Production, Storage Installation

Additional class notations are: -

- POSMOOR, CRANE, HELDK-SH, BIS

7.5.5.3 Statutory Codes and Standards

The FPSO Hull shall comply with the latest published editions of the following Rules and Regulations: -

- Maritime Regulations of the Registered Country / Flag state,
- IMO: "Code for the construction and Equipment of Mobile Offshore Drilling Units" (MODU) 1989 consolidated edition 2001 and latest amendments,
- IMO: International Convention for the Safety of Life at Sea, 1974 (SOLAS), consolidated edition 2004 and latest amendments, as relevant for a fixed unit,
- IMO: International Convention on Load Lines, 1966, as amended by IMO Res. A513(XIII), including Protocol of 1988,
- IMO: International Convention on Tonnage Measurement of Ships, 1969, as amended by IMO Res. A493 (XII) and Res. A494 (XII),
- IMO: Convention on the International Regulations for Preventing Collisions at Sea, 1972, as amended by IMO Res. A464 (XII), including amendments 1981 and 1987,
- International Electro Technical Commission (IEC), for electrical installations on board ships,
- International Tele Communication Convention (Torremolinos, Malaga 1973) with Annex and Revisions (Geneva, 1974) including GMDSS rules,
- ILO Convention Concerning Crew Accommodation on Board Ships (No. 92 and 133),
- IMO MSC/Circ. 474 Guidelines for Bow and Stern Loading and Unloading Arrangements in Oil Tankers,
- INMARSAT Convention on the International Maritime Satellite Organization, ICAO Annex 14,
- International Ship & Port Facility Security Code (ISPS Code) and SOLAS Amendments 2002.

7.5.5.4 Recommended industrial codes and standards

The following industrial codes, standards and recommendations of recognized bodies shall be used in design and fabrication of the FPSO and its components, where applicable. The latest revisions of all codes and standards will apply. In case of conflict between two Codes or Standards, the most stringent requirements shall prevail: -

- American Petroleum Institute (API),
- American National Standards Institute (ANSI),
- American Society for Testing and Material (ASTM),
- American Institute of Steel Construction (AISC),
- American Society of Mechanical Engineers (ASME),
- American Welding Standards (AWS),
- National Fire Protection Association (NFPA),
- Japanese Industrial Standard (JIS),
- National Electrical Code (NEC),
- International Electro Technical Commission (IEC),
- International Standard Organization, ISO.

7.5.5.5 Registration

The FPSO registration has yet to be confirmed.

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7.5.5.6 Met ocean Load Criteria

The facilities are designed for the following environmental return periods based on the Met Ocean data in the Basis of Design and Statement of Requirements: -

- 100 year (Design Extreme condition),
- 1 year (Maximum Operating Condition),
- 95% non-exceedance (Normal Operating condition),
- Fatigue sea states,
- Hull Structural Design.

The hull is designed to comply with European Safety Directive and DNV-GL offshore classification rules. The hull shall be designed to withstand the Karish Field Met Ocean design conditions and return periods required by European legislation and DNVGL, including the Met Ocean conditions associated with the transportation route.

Design and construction of the FPSO hull structure and mooring systems, including topsides primary structure shall be according to Classification Society rules and comply with regulatory requirements. Applicable rules and standards valid at the start of FEED shall be applied.

The design of the hull structure shall comply with the current requirements of the following standards, in this order of precedence: -

- European Safety Directive Statutory Requirements,
- DNVGL Classification Rules (OSS-102 and supporting Rules).

7.5.5.7 Marine Systems Design

The hull systems design concept for the Karish FPSO is based on Class requirements and conventional industry standard design. The hull compartmentalization, machinery, controls, equipment, and related systems are designed to properly interface with and meet the functional requirements of the topsides, process, utility, control, safety and reliability systems within established life-cycle parameters.

Hull systems machinery, controls, equipment, and related systems are designed for reliability and maintainability, in addition to established Project HSE requirements.

7.5.5.8 Ballast System

The ballast system is critical to the stability and safety of the FPSO and shall function reliably over a broad range of environmental, global response and loading conditions.

The system shall consist of designated tanks containing variable ballast, pumps, piping, manual valves, remote operated valves, check valves and other fittings, which shall enable transfer of seawater, as stated below: -

- From the sea to any given ballast tank(s) by either of two (2) independent internally submerged hydraulically driven ballast pumps,
- From any given ballast tank(s) to the sea by any of two (2) independent internally submerged hydraulically driven ballast pumps,
- Between any given ballast tanks using any of two (2) independent internally submerged hydraulically driven ballast pumps,
- Filling any given ballast tanks with the branch from the Sea Water system overboard line.

The ballast system shall be capable of managing any operational or emergency changes to the platform's payload and centre of gravity. The system shall also be designed to ballast and trim the hull simultaneously over a wide range of vessel stability and trim conditions during all pre-service operations.

7.5.5.9 Helideck

A helicopter deck, suitable for a Sikorsky S92A or equivalent type helicopter shall be provided on top of the Living Quarter. The helicopter deck shall be surrounded by a steel gutter, with drains and a safety net on a galvanised frame, with an integrated firefighting system and navigation lighting. The Helideck and associated facilities will be designed and built in accordance with the requirements of CAP 437.

7.5.5.10 Mooring

The mooring with consist of a 14 point spread moored system. The FPSO heading is 270Deg at a water depth of approximately 1700m.

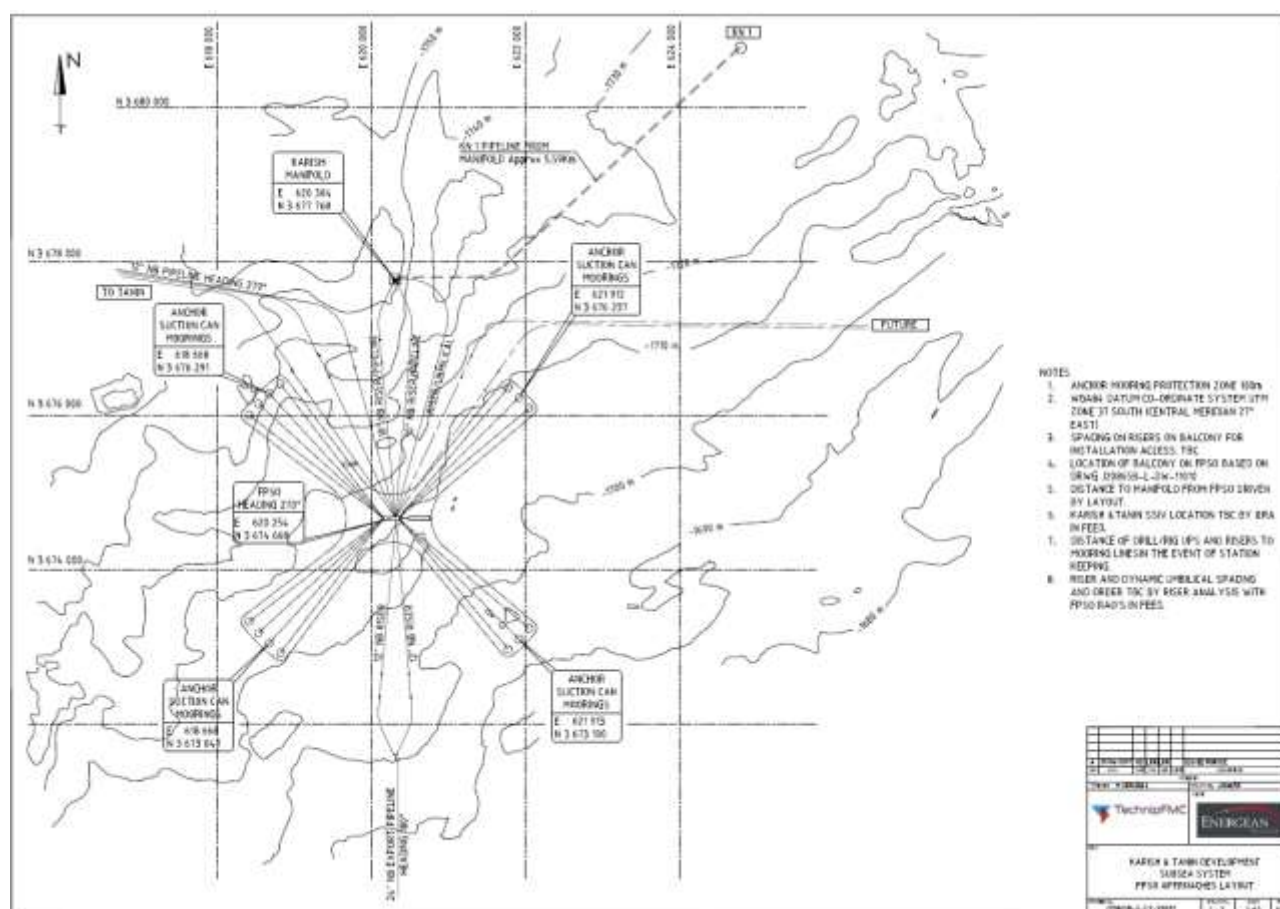


Figure 7-42 FPSO mooring arrangement

The proposed FPSO orientation has been selected, based on available information, to minimise the wave loading on the beam and quarter of the hull. This is achievable when the weather, especially waves, show a strong directional tendency. The BMT Argos Met Ocean Report gives maximum wind, wave and current values by direction and the report attachments, percentage occurrence by direction. Referring to this data and data from other projects in the area, it is known that the maximum wind is from the South-West but is only for a low percentage of the time and does not generate particularly severe waves. Also, North-West waves have a higher occurrence than those from the West but are significantly lower in height and period than Westerly waves. The general conclusion is to orientate the FPSO in an East-West direction, i.e. the FPSO will be orientated on a 270-degree heading. Two balconies are provided; one to the North side and one to the South. The North Balcony will take risers and umbilicals from Karish and Tanin and possible future developments and the South Balcony the export risers and SSIV umbilical and also provides for future export potential. The balcony's to the north and south with the FPSO heading allow the layout to be as simplified as possible and provide good access. The layout and facilities will be confirmed at the next phase with the RAO's from the vessel and confirmation of the riser and mooring design.

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The FPSO will be spread moored, and for the purposes of the FDP, the concept study assumes to have an anchor pattern comprised of a horizontal anchor distance of 2.2 km from the FPSO to the anchor point. The spread moored FPSO will need to be on station for the risers to be pulled in (from the FPSO) and tested as there is no detachable turret.

A 2x4 plus 2x3 mooring pattern has been provisionally selected, but this is heavily dependent on the final vessel RAO's and will be confirmed in the pre-FID engineering phase. Anchors are spaced with their centre line at 45 degrees to the heading at the bow and the stern and with a 10 degree angle between the anchor lines.

Chain stoppers for each mooring line and pretension winch system shall be designed for up to 300 tonne pre-tension. Each mooring line shall be a combination of chain top segment, polyester rope middle segment, and chain bottom segment that is connected to a suction pile anchor.

The riser spacing and order will be revised during the next engineering phase to optimise the spacing and the number of risers that can be accommodated. RAO's are being developed for the FPSO for Karish and Tanin and these will allow this work to be completed and the risers and umbilical's to be accommodated can be optimised.

Anchoring details will be dependent on the final size of the selected vessel, mooring analysis and soils data to be collected Q2 2017.

7.5.5.11 Oil Export

7.5.5.11.1 Offloading operation

Oil export will be by shuttle tanker. The FPSO will have a total oil storage volume of 800,000 bbls. Oil processed to export/sales specification will be stored in the central storage cells within the FPSO hull. These have a maximum capacity of 500,000 bbls. Each of these storage cells will be equipped with a high capacity caisson pump able to deliver directly to tankers moored in tandem mode.

Oil shall be pumped from the five (5) main centre tanks utilising the hydraulically operated deep-well pumps, via the fiscal oil export metering skid to the offloading hose reel to the tanker. The FPSO shall have an offloading capacity of 3000m³/h, allowing a 400,000 bbls parcel to be offloaded into the shuttle tanker within 24 hours. No additional pumps will be required on the topsides modules.

It is anticipated that the FPSO shall offload every 6 to 8 weeks, but due to high storage capacities within the hull, there is flexibility to optimise the offload according to operational and market constraints and opportunities.

Tankers will be moored to the stern of the Karish FPSO downstream of the prevailing weather systems. They will sit at a distance of around 300m and held in position by a 45 BP tug mobilised from Ashdod or Haifa. Alternatively the Karish "Supply Vessel" will be specified to undertake this role. The tanker will be connected to the FPSO by a reel mounted loading line with quick release couplings. Oil spill booms will be deployed from the Karish PSV or crew change boat, during loading operations in case of spills.

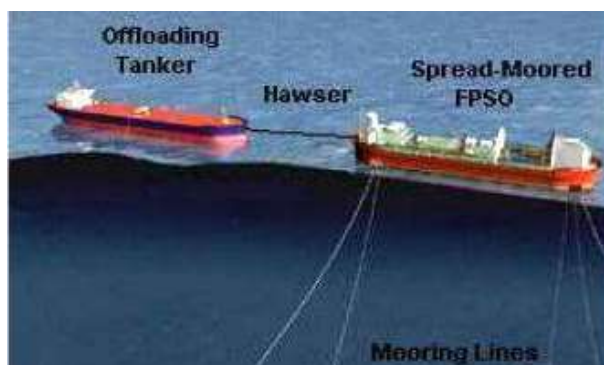


Figure 7-43 FPSO Tandem offloading operation

The FPSO will be designed to allow the loading hole to reel out under the central pipe rack for inspection and maintenance.

7.5.5.11.2 Inert Gas (Blanket Gas)

This is a marine system and will be used to blanket the cargo tanks during offloading. It will be generated using combustion gas produced by the marine blanket gas burners.

Inert gas or a nitrogen gas system (to be decided during the next design phase) will provide gas of sufficient purity – minimum 95% N₂ – for tank blanketing and compressor seal gas requirements. This gas can also be used for process purging at shutdowns. The system will be capable of maintaining a positive pressure in the tanks and be able to purge empty oil tanks of hydrocarbon gasses as part of a gas freeing process. In addition to the Inert Gas system the tanks shall be provided with a vent system to a safe location.

7.5.5.12 Diesel

Diesel is stored on the FPSO and will be used as the fuel supply to all the diesel engines. In addition, diesel will be used to provide Emergency power and an alternative fuel to the main power generators. The need for diesel purifiers is currently being reviewed and will depend on the quality of diesel supplies available and the final choice of gas turbines.

7.5.5.13 Aviation Fuel

There will be no Helicopter refuelling facilities on the FPSO.

7.5.6 FPSO Topsides Systems

The requirements for the FPSO topsides processing are summarised below:

Table 7-18: Field production rates (MDQ)

COMPONENT	INITIAL PHASE			FUTURE PHASE		
	Karish	Tanin	Total	Karish	Tanin	Total
Gas Throughput (mmscf/day)	400	0	400	200	400	600
Topsides (mmscf/day	400	0	400	200	400	600
Infield pipelines (mmscf/day)	400	0	400	200	400	600
Stabilised Light Oil (bbl/d)	8,960	0	8,960	4,480	2360	6,840
Produced Water (bbl/d)	2,000	0	2,000	1,000	2,000	3,000

An overview of the topsides processing block schematic is included below (Figure 7-44). The schematic shows all possible future provisions i.e. including future subsea MEG facilities as an alternative Tanin hydrate management philosophy.

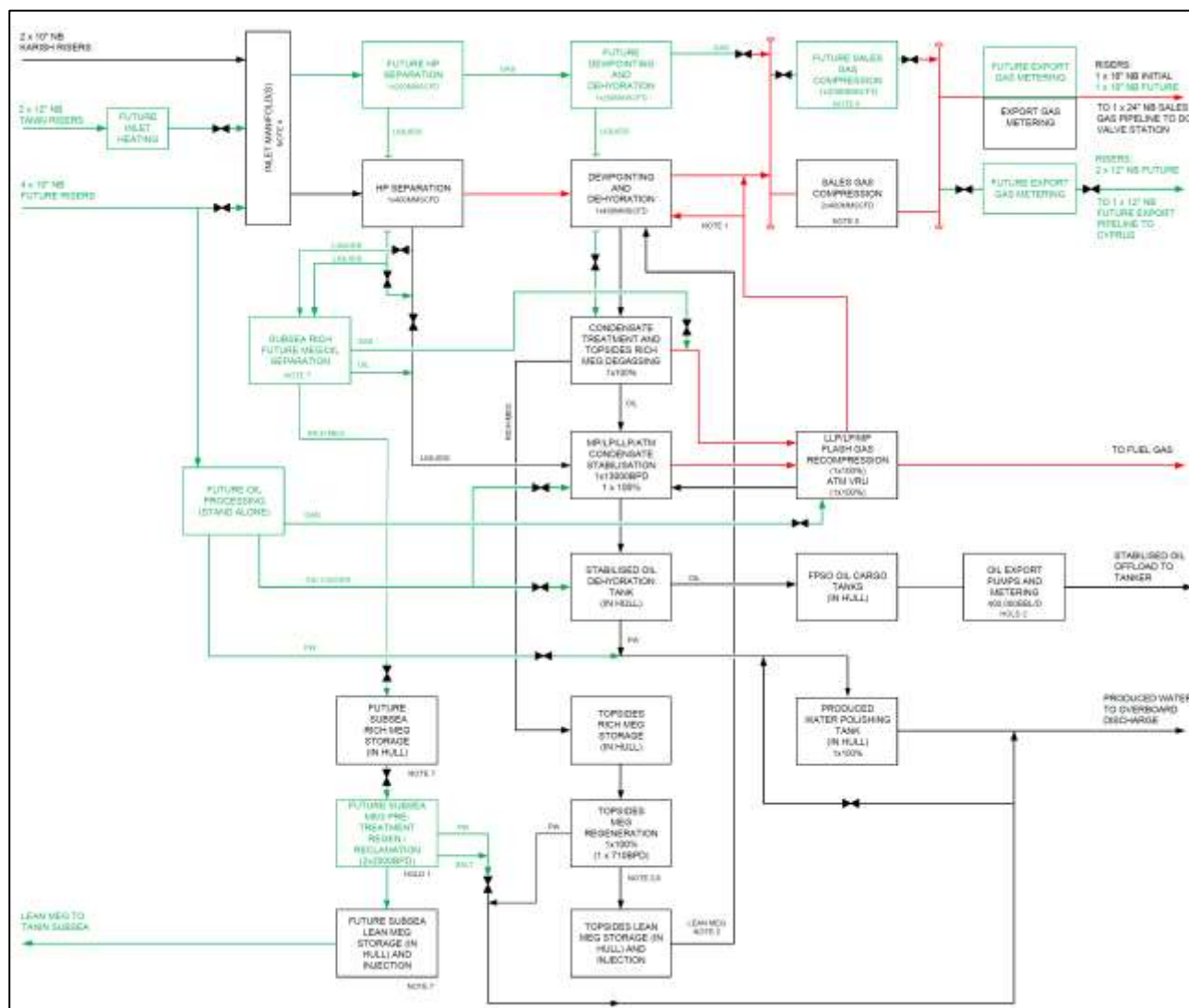


Figure 7-44 FPSO topside processing arrangement

The above schematic shows all initial systems in addition to all potential future expansions allowed for in the design.

An indicative topsides layout is shown below. This will be further refined as the project moves through subsequent design phases. Layout reviews have been undertaken during the concept engineering phase with a specific focus on minimisation of line lengths, HSE management, Operations and Maintenance management.

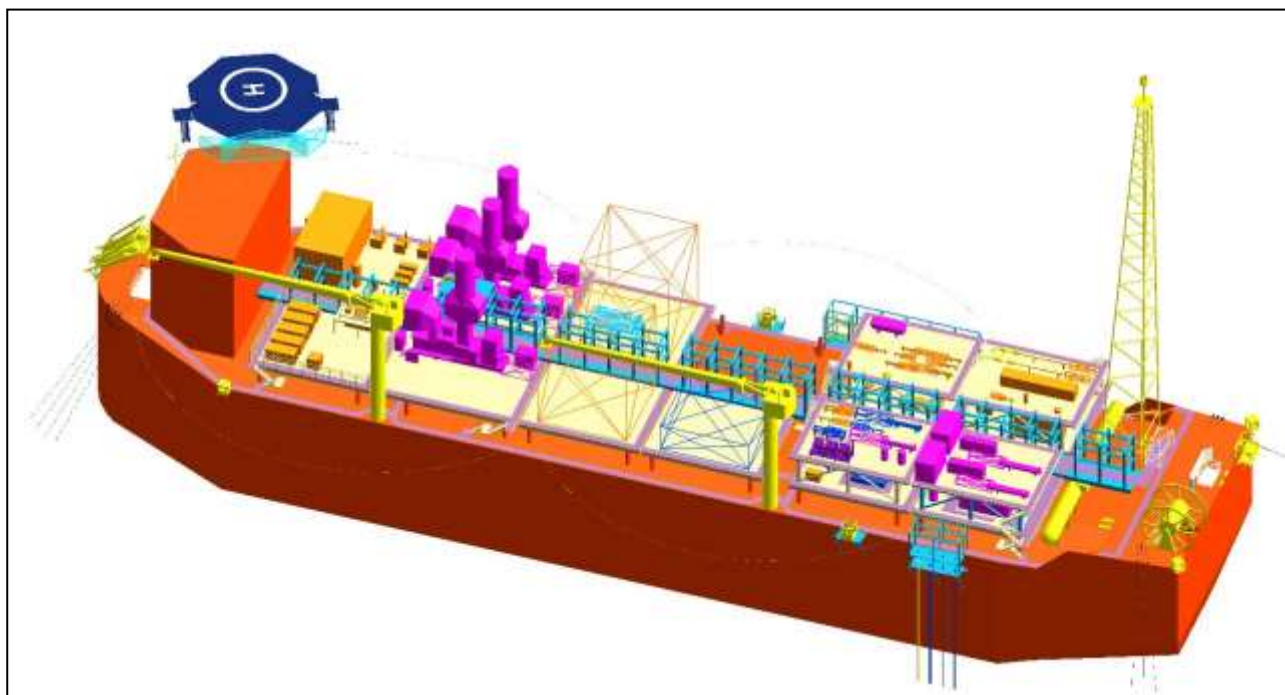


Figure 7-45 Indicative topside layout

7.5.6.1 FPSO fluid inlet facilities

The Karish reservoir fluids (from KM-1, KM-2 and KM-3 wells) are transported to the topsides Inlet Facilities via two production flowlines and 10" NB risers. The Karish reservoir fluids arrive at between 200 and 400 bar and 30 to 50°C. The arrival temperature is sufficiently high to be outside the hydrate formation region, therefore inlet heating is not required, and wax deposition or stable emulsions are not expected during normal operation.

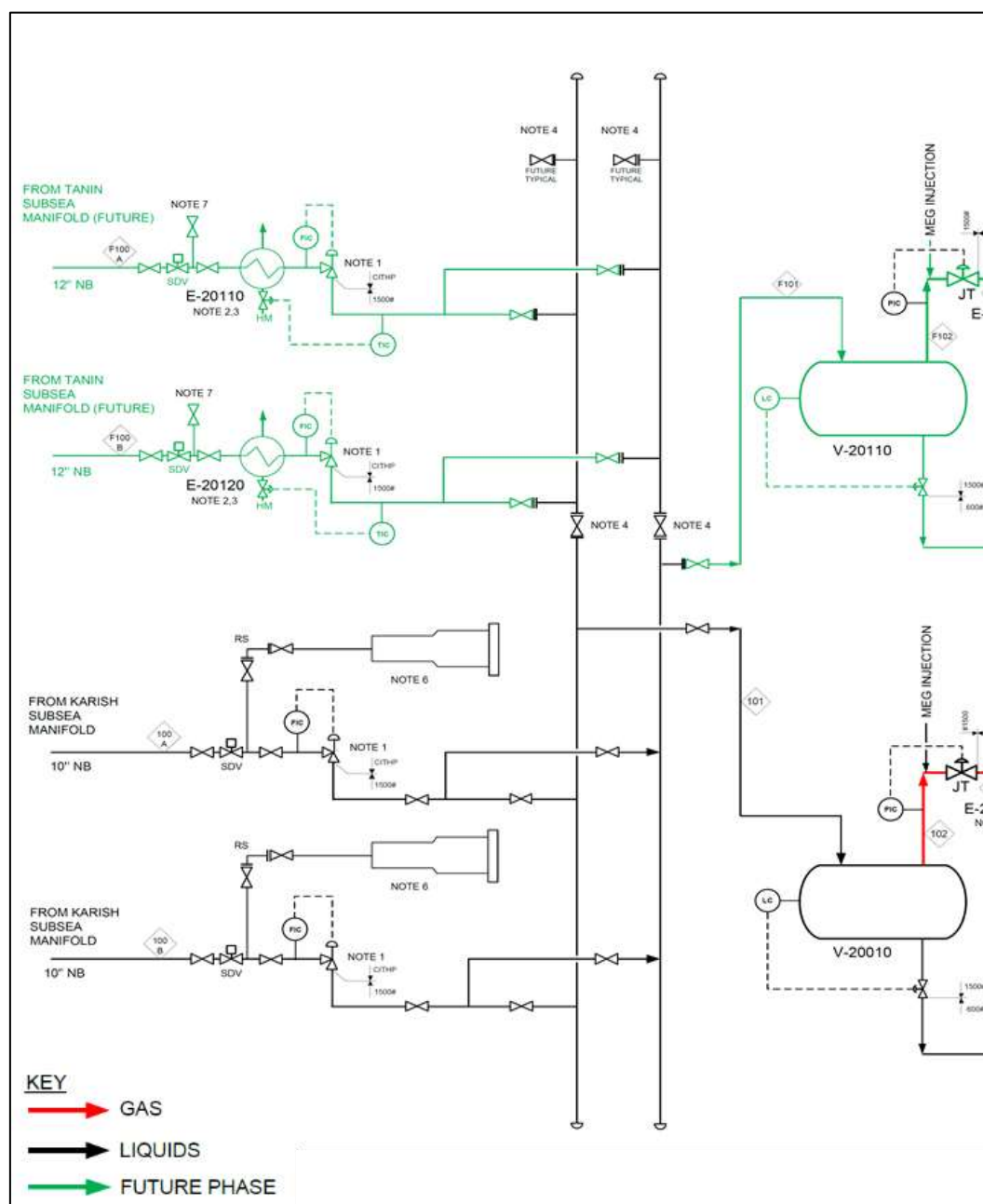


Figure 7-46 inlet facilities schematic

Pigging facilities

Pigging is anticipated to be an infrequent activity. Two common, dual role, receiver/launchers will be installed topsides on each of the initial Karish production risers to allow round trip pigging for inspection and cleaning of the initial and future riser pairs. Karish infield flowlines. Removable spools will be used to hook-up initial and future riser pairs as and when required.

Topsides Choke Valves

Each production riser is to be provided with a single topside choke valve. The choke valves are required to provide manual topsides flow control, with flow nominations anticipated to be adjusted each hour.

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Production Manifolds

Two inlet manifolds are provided, one each for the initial and future HP production separators. Pipe routing downstream of the topsides chokes will allow the initial and future risers to flow into either header. Expansion for tie-ins for 4 additional future risers are included on each of the HP separator inlet manifolds.

Overpressure Protection

The production risers and manifold piping up and to and including the choke valves are fully rated for the well shut-in pressure. A spec. break downstream of the choke reduces the rating to 1500#.

Overpressure protection for the production manifolds and separation systems is provided. Process Safety Valves (PSVs) will be located downstream of the choke valves to protect the manifold spec break. The PSVs will be sized for the full flow relief case.

HP Production Separator

The HP Production Separator, V-20010 will receive the multiphase reservoir fluid from the topsides chokes. It is a two-phase horizontal separator sized for 400 mmscf/day of gas and facilitates smooth operation of the downstream units by absorbing any liquid slugs from the flowlines. A slug allowance of 5 m³ is the current design basis for HP Production Separator, but the final volume will be confirmed during the Pre-FID engineering.

Potential Future Inlet Facilities

Manifold tie-ins (up to 4x10" NB) have been included in the design of the inlet facilities to support the production of Tanin and other third party fluids in the future. It is expected that Tanin fluids will require inlet heating and space provision for two Inlet Heaters, E-20110/20120 of shell and tube type has been included in the topsides design. The purpose of the inlet heaters is to heat the fluids above the hydrate formation temperature in the HP production separator to approximately 25°C.

As per the Karish manifold and piping design, the future fluids will be choked and the production risers and manifold piping up to and including the choke valves will be fully rated for the well shut-in pressure. A specification break downstream of the choke reduces the rating of the pipeline from #2500 (420bar equivalent) maximum to 1500# (260bar equivalent).

Overpressure protection for the future production manifolds will be systems provided. Process safety valves (PSVs), rated for full flow relief, will be located downstream of the choke valves to protect the manifold spec break.

Space provision for a second two-phase production separator, V-20110 has been included in the topsides design. The purpose of the future separator is to receive either Tanin fluids or redirected Karish fluids in the future following reservoir pressure depletion. The future separator will be sized for 400 mmscf/day operating at approximately 30-50°C, 200 Bara. Tanin (and / or other third party) fluids will be routed to the new HP Separator or the existing HP Separator, V-20010 operating at approximately 25°C and 200 bara.

7.5.6.2 Gas dew pointing system

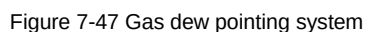
Pipeline sales gas will be tied into the Israeli gas grid via the INGL pipeline and shall meet the specification given in Table 7-19. The below is defined by a draft commercial agreement and may be subject to change.

Table 7-19: Envisaged gas sales specification

PARAMETER	SPECIFICATION
Water Dew point	Not greater than 0°C at any pressure up to and including 80 barg
Hydrocarbon Dew point	Not greater than 5°C at any pressure up to and including 80 barg
Hydrogen Sulphide	Not more than 8 ppmv of total sulphur expressed as H ₂ S
Carbon Dioxide	Not more than 3.0 mol%

Total Inerts	Not more than 5.0 mol%
Methane	Not less than 92.0 vol%
Higher Heating Value	Not less than 0.0346 MMBTU per m ³ and not more than 0.0395 MMBTU per m ³
Wobbe Index	Not less than 0.0462 MMBTU per m ³ and not more than 0.0509 MMBTU per m ³
Temperature	Not less than 5.0 & not more than 38.0°C and 10°C above Water Dew Point. Will be reviewed and updated if delivery point is not at Dor Valve Station
Pressure	Not higher than 80 bara and not lower than 60 bara. To be based on a range of 75 – 80 bara. Will be reviewed and updated if delivery point is not at Dor Valve Station.

Hydrocarbon and water dew pointing is required to ensure the gas meets the required export specification. The dew pointing facilities include two stages of JT cooling and liquid removal to meet the export specification and reduce liquid entrainment into the gas phase and are illustrated below. MEG is injected upstream of the JT valves to effective water dehydration.



Flash gas from the HP Separator, V-20010, is routed to the first JT valve and the pressure is reduced from 197 Bara to 130 Bara. The gas is further cooled through the Gas-Gas Exchanger (GGE) tube side, E-25010, to 4°C. The first JT valve is located upstream of the GGE to avoid shearing of the liquid droplets produced in the GGE. The GGE is a shell and tube type exchanger, to enable easy cleaning and minimise the risk of hydrate blockages. Two MEG injection points are provided upstream of the JT valve and the Gas-Gas

Exchanger respectively to prevent hydration formation. The injection point upstream of the Gas-Gas exchanger must be designed to effectively distribute lean MEG across the tube sheet.

The gas is then routed to the JT Inlet Scrubber, V-25010, to remove the liquids condensed from the gas resulting from the JT cooling across the first JT valve and Gas-Gas Exchanger. The cooled gas is further hydrocarbon dew pointed via a second JT valve and the resulting liquids are removed in the Low Temperature Separator (LTS), V-25020. MEG injection points are required upstream of the LTS JT valve to prevent hydrate formation as the gas pressure is reduced from 130 bara to 75 bara, corresponding to an LTS temperature of (-18°C). The cold gas exiting the LTS is passed through the Gas-Gas Exchanger shell side, E-25010, to cool the inlet gas before routing to the Sales Gas Compressors.

A bypass on the GGE is used to control LTS temperature, the JT valves are modulated by pressure controllers to maintain upstream pressures. The JT Inlet Scrubber, V-25010, and the Low Temperature Separator (LTS), V-25020, are 2-phase vessels with specialised internals to minimise liquid entrainment in the gas phase.

The below figures show the processing path of the Karish gas through the FPSO topside at the beginning of the field life, with very high landing pressures at the FPSO and significant choking, and towards the end of plateau where close to no choking occurs at the FPSO FCVs. There is an 8-10oC difference when entering the gas-gas heat exchanger. This is the sizing case of the Gas/Gas Exchanger. A better understanding of the landing conditions upstream the FPSO FCV evolution with time will be the focus during FEED to perform equipment sizing optimisation.

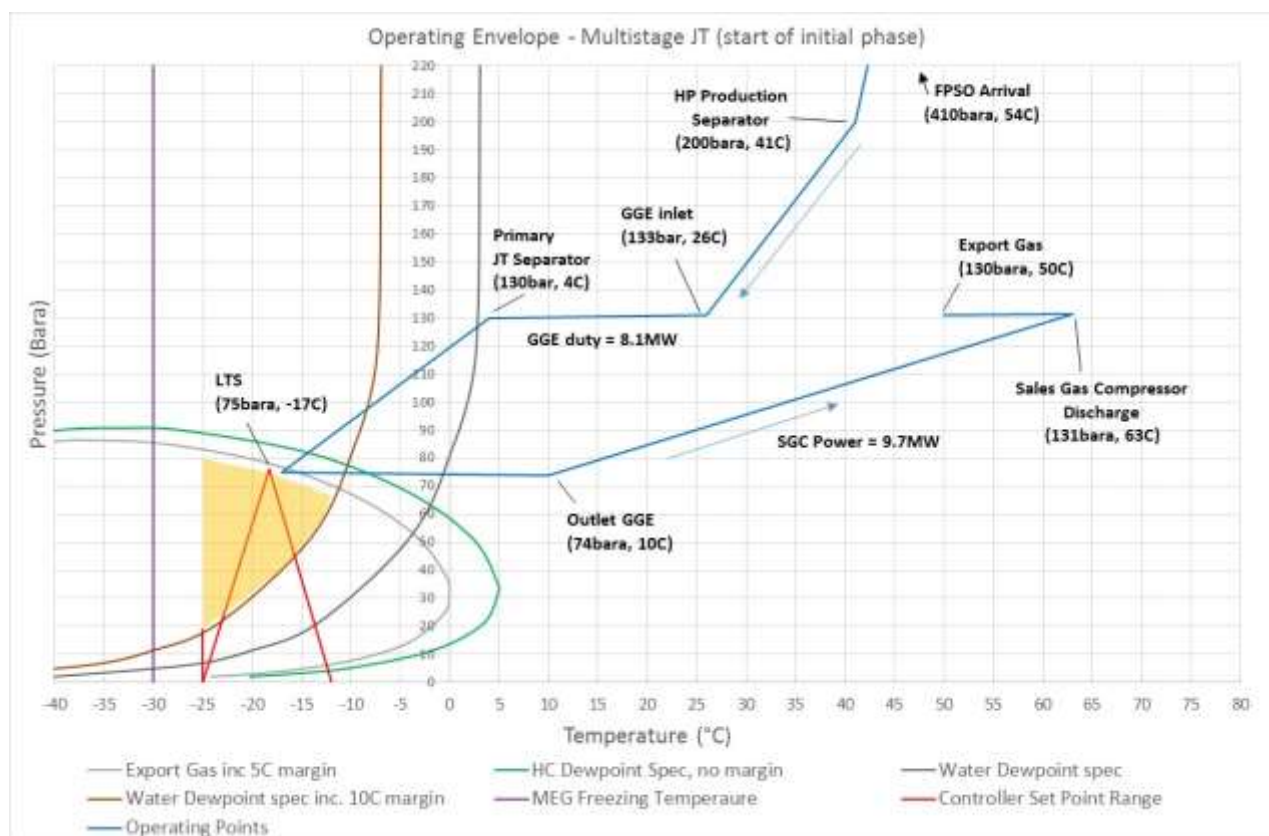


Figure 7-48 Karish gas processing path (Initial Phase with high choking levels at FPSO)

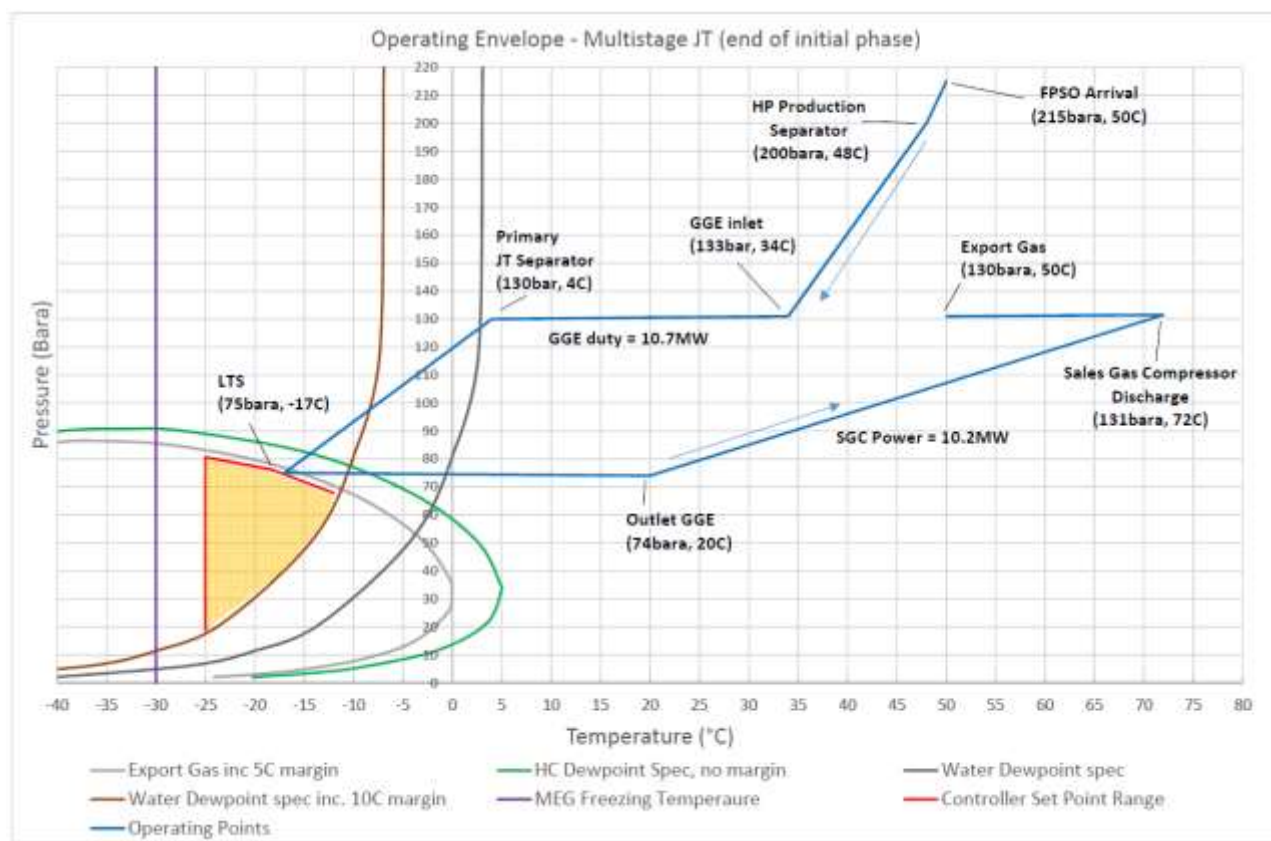


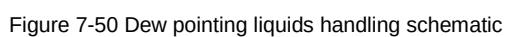
Figure 7-49 Karish gas processing path (End of Initial Phase with limited choking at FPSO)

Dew pointing Liquids Handling

Liquids from the JT Inlet Scrubber, V-25010, and the Low Temperature Separator (LTS), V-25020, are routed to a common manifold. The common liquid handling manifold includes tie-in provision for the future dew pointing system. The liquids, comprising of condensate and MEG, are heated via the Condensate Heater, E-26010 to 50°C and separated in the Condensate Treatment Vessel, V-26010, operating at ~45 bara, as shown in Figure 7-50.

Dew point system expansion

Additional dew pointing facilities are required to dew point gas volumes above 400 mmscf/day should production capacity be expanded in the future and following the addition of the Future Production HP Separator, V-20110. The flash gas from the future HP Production Separator, V-20110, is routed through two stages of dew pointing: JT valve and liquid removal as per the initial phase facilities, again with a capacity of 400 mmscf/day.



The oil separation and stabilisation is illustrated below. This is a simplified system based on flash separation and without a stabiliser column. Some recycling of liquids occurs. Topside facilities provide for Gas /Liquid separation whilst Oil and Water are separated in the hull storage tanks.

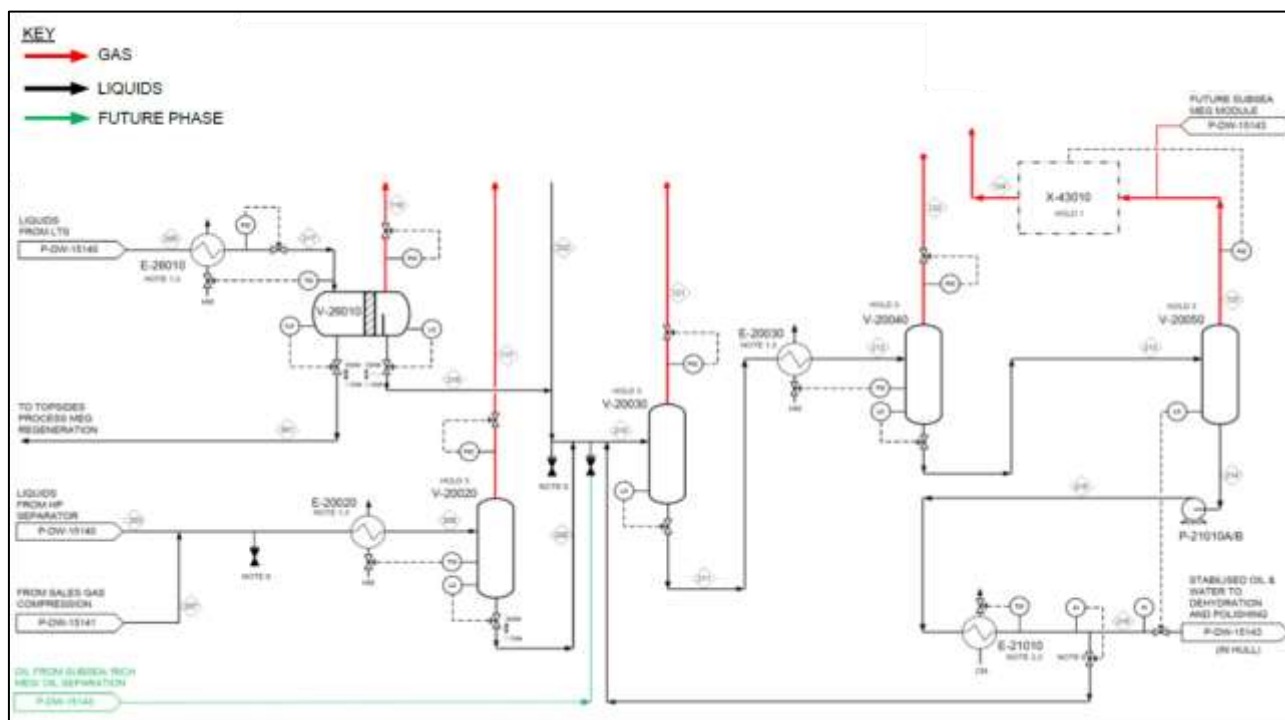


Figure 7-51 Gas/liquid separation and oil stabilisation system

The liquids separated in the HP Separator, V-20010 and the Export Compressor Scrubbers, V-27010A/B are routed to the MP Separator, V-20020. The MP Separator is a two-phase separator operating at approximately 47 Bara and 50°C. A liquids heater upstream of the MP separator, E-20020, is used to maintain temperature in the MP Separator. 50°C is recommended to enable good separation of possible emulsions.

The light oil separated from the MP Separator is routed to V-20030 (LP Separator), heated by the LLP Heat Exchanger E-20030 to >64°C, and then to V-20040 (LLP Separator) and V-20050 (Atm. Separator) to stabilise the oil before it is routed to the cargo tanks at >60°C. An Oil Rundown Cooler, E-21010 cools the oil to 50°C. The Oil Rundown Cooler is a shell and tube type heat exchange using closed loop cooling water. The stabilised oil product is routed to dehydration storage tanks in the hull. Bulk oil/water separation is performed in the hull, utilising the long storage times between oil offloading. A minimum turndown recycle line is provided to circulate cold stabilised oil to the LP Separator (V-20030) to aid turndown operation if required. The need for the rundown pipework will be design to avoid the need for this equipment and to maintain the oil temperature as warm as possible as it enters the dehydration tanks.

Light oil will be offloaded to shuttle tankers according to specifications given below.

Table 7-20: Light-oil/Condensate tanker offloading specification

PARAMETER	SPECIFICATION	NOTES
RVP at 38° C	10 psi	
TVP at 50° C	12 psia	
BS&W	0.5 %	

7.5.6.4 Flash Gas Compression

The Flash Gas Compression system is illustrated below in Figure 7-52.

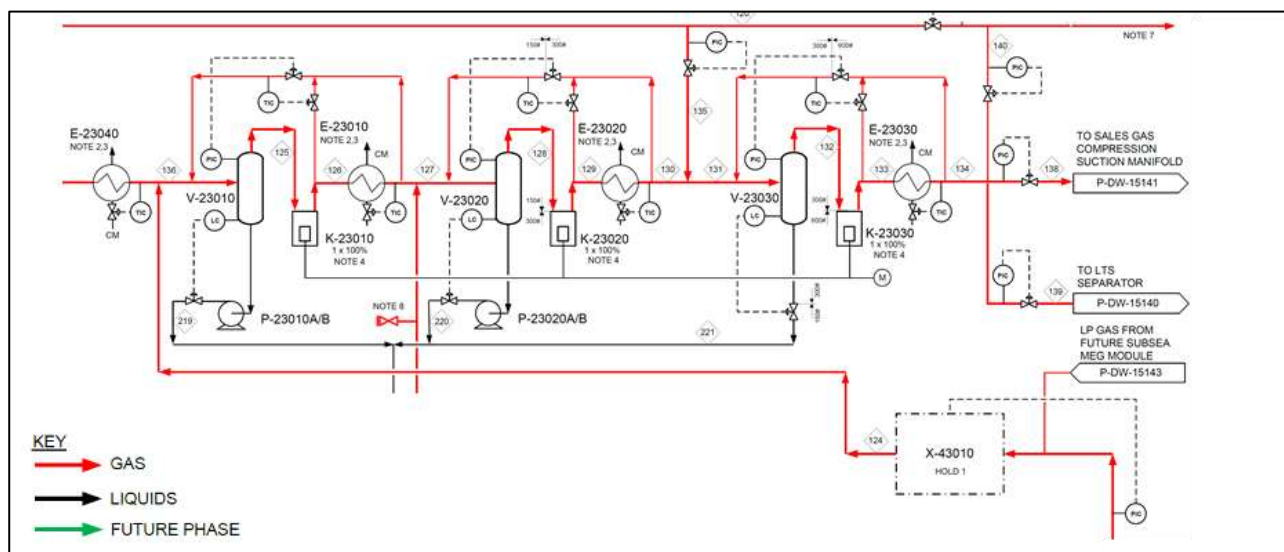


Figure 7-52 Flash gas compression schematic

Off-gas from the MP Separator V-26010, LP Separator, V-20030, and the LLP Separator V-20040, is compressed by three stages of flash gas recompression. Each stage has 1x100% duty and comprises:

- Two-phase suction scrubbers, V-23010, V-23020 and V-23030, to remove liquids from the gas;
- Electric-driven, reciprocating compressors on a common shaft, K-23010, K-23020 and K-23030. The three stages of recompression compress the gas from 2.7 Bara to export pressure of 80 Bara with intermediate pressures of 7 Bara and 23 Bara.
- Aftercoolers of shell and tube exchanger type, using indirect closed loop cooling medium, E-23010, E-23020 and E-23030, cool the gas to 50°C.

The discharge of the 3rd Stage Flash Gas Compressor can be routed to the LTS or sales gas compressor suction manifold. The fuel gas is taken off at the 3rd stage of Flash Gas Compression. Surplus flash gas from the Condensate Treatment Vessel, V-26010, and MP Separator, V-20020, is routed to the 3rd Stage Flash Gas Compressor Scrubber, V-23030.

The liquids removed from the 1st, 2nd and 3rd Stage Flash Gas Compressor Scrubbers, V-23010, V-23020 and V-23030 are recycled to the LP Separator, V-20030 and LLP Separator, V-20040 inlet for stabilisation.

Flash Gas Compressor Control

Considering the possibility of lower than design well fluid CGR and turndown sales gas nomination rates, the flash gas compressor may run in turndown mode for extended periods. The flash gas compressors will use recycle valves to control inter-stage pressures. Aftercooler bypass valves are required to maintain suction scrubber temperatures during turndown to avoid excessive hydrocarbon recycle.

7.5.6.5 Shrinkage factors

Process simulation performed during concept select phase have quantified the gas shrinkage as a function of gas through put feeding the FPSO expressed in volumetric basis:

- 0.8 to 1% of the feed to the FPSO is used for Fuel gas (**Note:** 1% used when developing the production profiles),
- 1.5 to 1.7 % of the feed to the FPSO is lost to the liquids (**Note:** 1.5% used when developing the production profiles).

In average the shrinkage is 2.5% on a volumetric basis.

Example:

For a total of 410.25 mmscf/day coming from the reservoir:

- 4.1 mmscf/day is used for fuel gas,
- 6.15 mmscf/day equivalent is lost to the liquids,
- 400 mmscf/day is available for gas sales.

7.5.6.6 Liquid Yields

Energean has worked extensively on process simulation and fluid characterisation exploiting the down hole sample data of Karish and Tanin performed by previous Lease owners. It is critical to understand that the liquid yields reported in the laboratory analysis and in the reservoir engineering PVT section represent the liquids that form as a result of a direct flash of the reservoir fluid to atmospheric conditions.

Additional liquids are created when the flashed gas at atmospheric conditions is treated to the sales gas specification. The yield of these “condensates” depend on the processing scheme employed and can be significant. All liquids produced on the FPSO either by depressurisation or dew pointing are combined into a single product stream.

Produced hydrocarbon liquids from Karish and Tanin have been defined as a combination of “Light Oil” produced from a single stage flash of the reservoir fluid samples at standard conditions (60F and 0 psig) and “Condensate” recovered from the hydrocarbon dew pointing unit. The condensate portion could also be defined as “NGL’s” according to SPE definitions. These hydrocarbon liquids have separate condensate gas ratios (“CGR Oil” and “CGR Condensate”) which added together give a “Total CGR” for the production facilities.

The resultant CGR’s for Karish ‘C’, Tanin ‘B’ and Tanin ‘A’ sands [Ref 7-1] based on total oil production calculated using Hysys are given in the table below. These CGR’s can be used to predict export volumes of stabilized condensate. It is noted that the majority of Tanin reserves are located in the ‘A sands’ which are slightly less rich than the ‘B’ sands however the conservative Tanin ‘B’ sand CGR’s has been used for the design of the Karish FPSO Oil train.

The CGR “condensate” portion, as previously defined, is significant and around 60 to 70% of the CGR measured by simple flash gas analysis (as was performed on some samples obtained from the Karish and Tanin exploration wells). They significantly increase the liquid reserves and revenue stream of the project. Removal of the “liquids” from the produced Karish gas results in a shrinkage of about 1.5% in the gas volume. This shrinkage is allowed for in the gas forecasts but not in the stated GIIP’s (i.e. the GIIP’s include the liquid fraction).

Table 7-21: Karish & Tanin reservoir fluid liquid yields (SGS Sample 1.03 & SGS Sample 6&4)

LIQUID YIELDS		KARISH (C SAND)	TANIN (B SAND)	TANIN (A SAND)
Light Oil (Single stage flash at 0psig and 60F)	CGR “ Oil” (bbl/mmscf)	13.4	3.9	2.2
	API	42	40	41.5
Condensate	CGR “ Condensate” (bbl/mmscf)	9	2	2
	API	57.2	50.7	50.7
Total Liquid yields	Total CGR (bbl/mmscf)	22.4	5.9	4.2
	API	51	45.3	48.5

Table Note: The Total CGR for the Karish B sands has not been determined as no laboratory flash work was undertaken. Simulation work on the reservoir fluids indicates a CGR of 6 to 9. Energean has used a CGR of 6 when calculating the projects liquid profile

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7.5.6.7 Crude Oil dehydration and Produced water de-oiling system

The water associated with the production of the Karish and Tanin fields is of two types:

- Condensate water: known low quantities (0.25 to 0.35 bbl/mmscf) – no salt,
- At 3BCM/year approximately 90bbl/d of condensate water will be collected, of which 50% will be evaporated during the topside MEG regeneration system. This means that at design capacity we expect to produce ~45 bpd of produced water,
- Formation water: unknown quantities – higher salt contents (28,000 ppm),
- Energean has tentatively set a design criteria to handle formation water of up to 5 bbl/mmscf. This value may be revised as the project progresses. The designed system is very tolerant of higher produced water levels as MEG is not envisaged, the oil stabilisation vessels are designed for gas removal and excess water storage capacity is provided.

Through reservoir and well engineering design studies and the reservoir production philosophy applied, efforts are made to avoid early water breakthrough and hence the processing of significant volumes of water for extended periods. Simulation models show that after water breakthrough occurs most (>95%) of recoverable gas volumes have been achieved. However reservoir modelling cannot simulate all reservoir heterogeneities and it is therefore possible that larger volumes of water will have to be managed for a longer period. This may be particularly true when gas is being produced from the B sands in Karish Main (thin laminated sands with more complex connections to the water leg) and Tanin C (shallow structure with production from horizontal wells close to the GWC).

Taking the above into account it was clear that the well completion, SPS and topside designs implemented need to be tolerant of a degree of WGR uncertainty. This was a key consideration of the desire to move away from a MEG-based hydrate management strategy.

As no data is available regarding the ability of the Karish and/or Tanin liquids to form stable emulsions with water or condensation of formation water it was considered prudent to avoid topside process systems that rely on three-phase separation. Hence options to stabilise the produced liquids at an elevated temperature and pressure in a column were avoided even though these would limit volumes of gas produced at low pressures and the degree of liquid recirculation in the flash gas compressor system. It was considered prudent to plan on separating water and oil in the vessels storage tanks and live with a less efficient flash gas system design than vice versa.

By employing an FPSO, storage volume equivalent to a large onshore oil and gas field is provided. This can be used when liquid production rates are low to reduce the complexity of oil dehydration and water de-oiling facilities. The processing scheme to be applied in the current FDP is outlined in Figure 7-53 below, where it is illustrated how part of the FPSO storage capacity is used to simplify the production of dry oil and oil-free water.

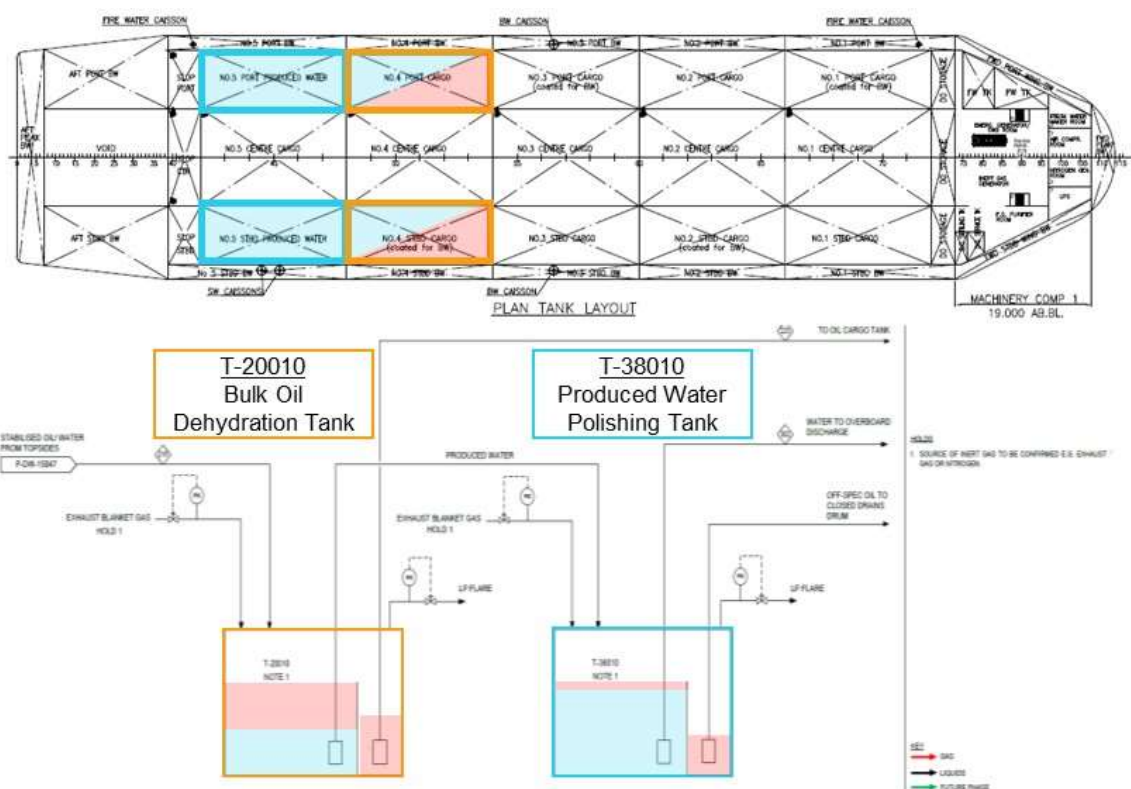


Figure 7-53 Produced Water Process Flow Scheme

Oil and water are kept together until fully stabilized. Dehydration takes place at atmospheric conditions in two cells of the FPSO hull (Volume=100,000bbl; Workable =95,000bbl; Oil volume = 65,000 bbl and water volume = 30,000 bbls). This bulk dehydration stage will allow achievement of the required BS&W spec for the crude that will then be transferred to a further 6 storage cells (300,000 bbl volume) where any remaining water will settle out at their bottoms and be removed.

Produced water will slowly accumulate at the bottom of the dehydration tanks and will eventually be transferred to two other cells (Volume=100,000bbl; Workable =95,000bbl) for polishing, where any residual oil will be free to slowly migrate to the tops and any potential chemical injection (emulsion breaking) may be applied.

Produced water, dehydration and crude oil storage tanks can be isolated and inspected without a shutdown.

The produced water rate range based on an average 3 BCM/year throughput and a formation water WGR capped at 5 bbl/mmscf lies between 45 bpd (water of condensation only) and 1450 bpd. The proposed system therefore provides around 7 years storage capacity when only water of condensation has to be treated and 80 days in the years after water breakthrough occurs. This gives Energean a high degree of confidence that produced water environmental discharge limitations will be met without need for exotic clean up technologies.

7.5.6.8 Sales Gas Compression System

The selected Sales Gas Compression system is based on the following configuration:

- 2 x 100% Compressors, each sized for the Phase 1 flow rate of 400 mmscf/day,
- The compressors will be driven by variable-speed electric motors,
- Because of the high availability of electric motor compressors, it is proposed that they will operate in parallel as 2 x 50% machines during Future Phase 2

The configuration is illustrated below.

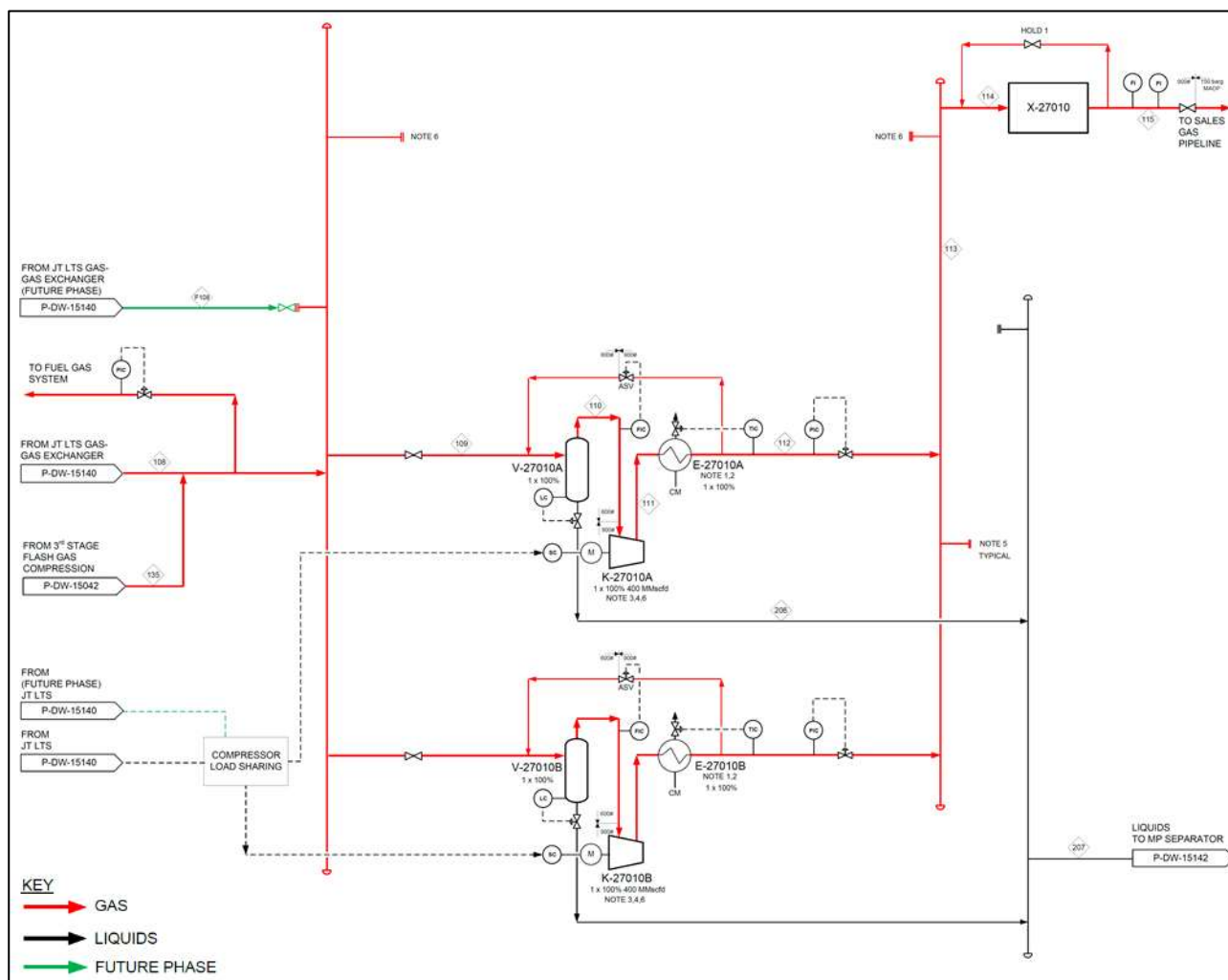


Figure 7-54 Gas export compression schematic

The dew pointed gas exiting the Gas-Gas Exchanger, E-25010, is compressed to meet sales gas delivery pressure onshore. The actual discharge pressure required depends on the pressure in the INGL transmission system at Dor, the amount of line pack achieved in the dry-gas export line and the flowrate. A maximum pressure of 130 barg is envisaged. The 2 x 100% compression trains have a nominal maximum capacity of 400 mmscf/day each at 130 barg discharge pressure and include:

- A common inlet manifold with tie-ins for future compression,
- Sales Gas Compressor Scrubbers, V-27010 A/B, are two-phase vessels sized for 400 mmscf/day each, designed to remove entrained liquids,
- Sales Gas Compressors, K-27010A/B, will compress the dew pointed gas from 70-80barg to 130 barg. The compressors will be of centrifugal type with variable speed electric motor drivers,
- Sales Gas Compressor Aftercoolers, E-27010 A/B, will cool the compressed gas to approximately 45°C. The aftercoolers are of shell and tube type exchangers using indirect closed loop cooling medium. The sizing case for the discharge coolers will be the recycle mode.

7.5.6.8.1 Future Sales Gas Compression

It is anticipated that no additional compression will be installed should the second gas inlet and processing system be installed increasing the FPSO capacity to 800 mmscf/day. At this point the 2x100% units will effectively be down-rated to 2x50% units.

As electrically driven centrifugal compressors have been specified high uptimes will be achieved and it is presumed availability targets can be met with no sparing. However, there is space available for an additional identical electrically driven compressor (400 mmscf/day) should it be decided at a later date that this compression would be beneficial.

7.5.6.8.2 Sales Gas Compressor Control

The Sales Gas Compressors will be throttled by speed control to maintain LTS pressure. They can operate with discharge pressure throttling to maintain 130barg discharge or float on the discharge manifold pressure, which will vary depending on the sales gas rate. The two Phase 1 compressors will be manifolded to operate on a common suction manifold or in segregation. For common suction manifold mode, compressor load sharing will be required. Anti-surge control valves will maintain machine minimum flow during low turndown.

The gas discharged from the Sales Gas Compression trains will enter a common manifold and pass through a fiscal meter (Sales Gas Metering Package, X-27010) prior to entering the Sales Gas pipeline. Having the fiscal meter offshore allows for commingling with other fields at the INGL subsea manifold, which may be installed in the future.

The Sales Gas Metering Package will include an automatic sampling system for gas quality measurement (calorific value, dew point analysis, contaminants etc.) and likely sampling points for INGL gas sample collection.

The common sales gas manifold includes provision for tie-ins for a future gas meter and an additional 16" NB INGL sales gas pipeline riser and 2 x additional 12" NB export risers.

7.5.6.9 Product Specification and Metering Systems

The expected sales gas quality is identified below:

Table 7-22 : Sales Gas Specification

PARAMETER	SPECIFICATION
Water Dew point	Not greater than 0°C at any pressure up to and including 80 barg
Hydrocarbon Dew point	Not greater than 5°C at any pressure up to and including 80 barg
Hydrogen Sulphide	Not more than 8 ppmv of total sulphur expressed as H ₂ S
Carbon Dioxide	Not more than 3.0 mol%
Total Inerts	Not more than 5.0 mol%
Methane	Not less than 92.0 vol%
Higher Heating Value	Not less than 0.0346 MMBTU per m ³ and not more than 0.0395 MMBTU per m ³
Wobbe Index	Not less than 0.0462 MMBTU per m ³ and not more than 0.0509 MMBTU per m ³
Temperature	Not less than 5.0 & not more than 38.0°C and 10°C above Water Dew Point
Pressure	Not higher than 80 bara and not lower than 60 bara. To be based on a range of 75 – 80 bara

Table 7-22 shows the envisaged sales gas specification. The defined delivery point is expected to be at the inlet to the INGL gas system at the 10 km point in the dry-gas pipeline to shore. Metering cannot be undertaken at this point and hence Fiscal Metering will be performed on the FPSO. Flow (and/or pressure) control will also take place at DVS and (non-fiscal) flow metering will also therefore be required at this location. The following philosophy is proposed:

- Fiscal flow measurement, by means of an ultrasonic meter and turbine meter in series with a spare metering line (see Figure 7-55 below),
- CO₂, Calorific Value and Wobbe Measurement (compositional analyser),
- Water Dew point by a moisture analyser,
- Hydrocarbon dew point by a hydrocarbon dew point analyser,
- Hydrogen sulphide by a sulphur analyser.

Sample points for offline measurement of the above parameters will also be provided on the FPSO. Verification of the accuracy of the above online measurement facilities will be carried out by means of laboratory analysis at annual intervals (or more frequently, as determined by INGL).

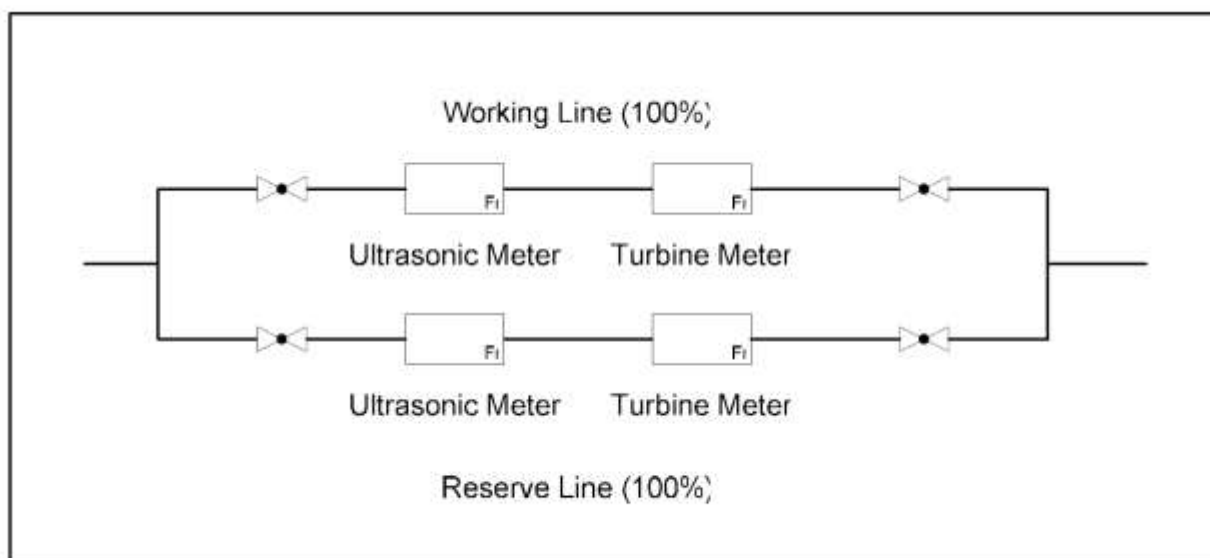


Figure 7-55 Sales gas metering requirements

7.5.7 Export Oil from the FPSO

Table 7-23 : Light oil Offloading Specification

Parameter	Specification	Notes
RVP at 38°C	10 psia	
TVP at 50°C	12 psia at maximum possible storage temperature.	Temperature could be optimised dependent on the cooling medium provided in the oil treatment unit.
BS&W	0.5 %	

Oil offloading is expected to occur infrequently due to the large cargo storage capacity and relatively low oil production rate. Table 7-23 shows the oil export specification currently considered for design purposes. This is a typical commercial oil specification which is subject to change.

Specifics on oil metering and oil quality measurement are to be developed further in pre-FID engineering, the basic requirements envisaged at the offloading point are summarised below:

- Online Fiscal oil metering (N+1 sparing for design offloading rate of 300,000bbl/d)
- Sample points for offline laboratory measurement of:
- RVP
- TVP
- BS&W

Sample points for measuring oil quality are also envisaged to be required prior to routing product oil to the cargo tanks, to ensure stored cargo meets the offloading specification.

7.5.7.1 Power generation

The FPSO power generation systems shall comprise two sub-systems:

- Main power generation (located on the Topsides), and
- Emergency power generation (located in the Hull).

7.5.7.1.1 Main power generation

The FPSO power philosophy shall be based around a central power plant (CPP) with all electric process and utility drives. Hazardous Area Classification of both the hull and topsides shall comply with the requirements of EI 15. The functional requirement for the main power generation system shall be to generate power in the CPP at 11 kV for all FPSO and subsea power consumers, based on a frequency of 50Hz. The CPP shall have a high availability and maximum operating flexibility.

Main power generator equipment selection and configuration shall include: -

- Three (4th unit required for Tanin DEH and/or capacity increases) dual fuel (fuel gas and diesel) turbine drivers,
- Waste Heat Recovery Units (WHRU's) for heat supply to FPSO heating medium. Two WHRU shall be installed initially. A 3rd WHRU would be installed with the 4th GTG for Tanin should a MEG hydrate management philosophy be adopted,
- Commercially available power generator sets with proven offshore operating experience, i.e. Siemens or General Electric,
- Avoid use of aero derivative units to simplify maintenance requirements.

The CPP shall provide all electrical power generation and distribution to support the process, utility, subsea and hull requirements over the design life of the field. The Power Management System (PMS) shall provide control and monitoring of the electrical power generation and distribution system. The PMS shall incorporate

a microprocessor based load management system to provide generator load sharing control and an automatic load shedding facility. The PMS shall communicate critical information with the PCS system and display it on the ICSS HMI display. The PMS shall be configurable in different load condition modes and if a fault occurs in PCS system, the PMS shall operate properly and prevent cascade tripping of the engines/generators.

The PMS shall control: -

- Load sharing,
- Load shedding,
- Start/stop limit for engines/generators,
- Main distribution and selected circuit breakers.

Power Generation selection is based on units supplied by either Siemens or GE. Final choice of unit size and make will be determined in the next phase. For the sake of the FDP a configuration based on SGT-400 units is assumed (13.4 MW ISO and a site rated output of 10.9 MW per machine).

Initial and future phase electrical loads and an electrical load list summary for the FDP development is summarised below. An 800 mmscf/day future sales gas rate case has also been considered as a sensitivity. An N+1 sparing philosophy is assumed for the power generation GTs.

Table 7-24: Power generation summary

SALES GAS RATE (PHASE)	ELECTRICAL LOADS (MW)		GTG CONFIG
	RUNNING	DESIGN	
400 mmscf/d (Initial)	17.1	19.5	3x50% SGT400
600 mmscf/d (Future)	26.4	29.9	4 x 33% SGT400
800 mmscf/d (Future Max)	33.2	34.8	4x33% SGT400/4x25% at peak demand

For this scenario, the largest electrical loads are the sales gas compressors, requiring 11.1MW absorbed power for 400 mmscf/day. During the initial phase only, 1 out of 2 sales gas compressors will be operating continuously while, the other remains on standby. However, smooth changeover from the duty to standby compressor (a standby compressor is started before duty compressor is stopped) must be considered.

The initial phase design electrical load is 19.5MW and can be provided by 3x50% SGT400 GTGs (rated power 10.9MW each). During compressor switchover the running electrical load will increase to approximately 25-30 MW. The standby GTG will be brought on-line when performing compressor changeover.

In the future, power generation capacity must be available to continuously operate both sales gas compressors simultaneously, in:

- 2x75% configuration (300 mmscf/day each) for a 600 mmscf/day total sales gas rate, or
- 2x50% configuration (400 mmscf/day each) for an 800 mmscf/day total sales gas rate.

In addition, power must also be supplied for the electrical heating of the Tanin pipelines as part of the Tanin hydrate management strategy. In the event that MEG is selected, then this will require an electrical power supply to the following electrical equipment:

- Future subsea MEG injection pumps;
- Future MEG transfer pumps;
- Future heating medium circulation pumps;
- Future cooling medium circulation pumps;
- Future seawater lift pumps;
- Future fuel gas heater.

The power consumption for the DEH or the future subsea MEG is similar and in the order of 3 to 5MW. It is expected that the DEH consumption will not be continuous.

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For a 600 mmscf/day future sales gas rate, the future design electrical load is 29.9MW. The installation of a future, additional SGT400 GTG is proposed, i.e. to achieve a future GTG configuration of 4x33% SGT400 GTGs, to meet the increased future electrical loads and ensure high availability.

For an 800 mmscf/day future sales gas rate, the future design electrical load increases to 34.8MW. The installation of a future, additional SGT400 GTG and operating in a 4x33% configuration will only provide 32.8MW of electrical power, which is insufficient for the extreme case. However, it is recognised that this includes a 10% margin on electrical sizing and is based on the site rated maximum ambient temperature. Most of the time, it will be possible to meet the export duty requirements for the 800 mmscf/day case. In exceptional periods of high power demand, the fourth generator will be brought online.

7.5.7.1.2 Emergency power

The emergency power generation system shall provide emergency power to the 690V emergency switchboard. The emergency supply shall normally be supplied from the 11kV main power generation on the topsides.

Emergency loads shall be those affecting personal safety (safety critical) whether directly or indirectly and inducing risk of major damage on the installation or equipment. These loads shall be connected to switchgear with an emergency source of power (e.g. batteries, inverter fed from batteries, etc.) backed up by the emergency generator.

Various equipment, defined as essential consumers shall be provided with uninterruptable electrical power supplies according to DNV and SOLAS rules.

The emergency power generation shall, in the event of failure in the main power availability, supply power to all essential services considering the safety of the FPSO including:

- All emergency loads as defined by the classification society,
- Active fire protection systems,
- Emergency lighting,
- Evacuation / escape systems,
- All telecommunications systems required for emergency response,
- ICSS systems,
- Alarm and PA/GA system,
- Fire and Gas (FGS),
- Process Control System (PCS),
- Essential HVAC systems,
- Helideck perimeter and obstacle lighting,
- Black startup loads for minimum of one of the main power generators,
- Battery chargers for all AC and DC UPS systems,
- Emergency air compressors,
- Any other miscellaneous essential process loads,
- Control of ballast pumps (as required by class),

7.5.7.2 Utility systems

An overview of the utility systems and topsides-hull interfaces are shown in Figure 7-56. Details of individual systems are provided in the following sub-sections.

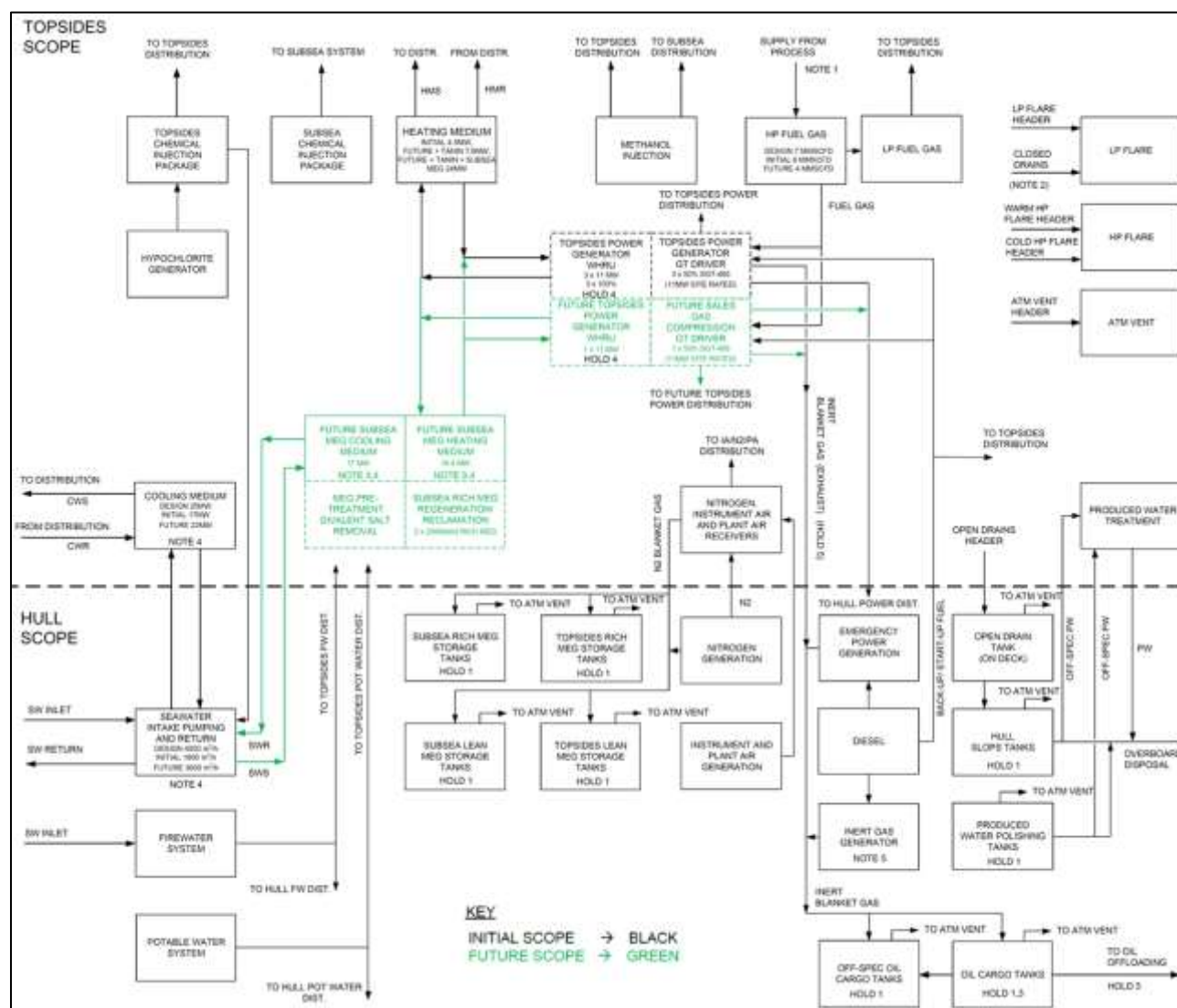


Figure 7-56 Utility System Overview and Topsides-Hull Interfaces

7.5.7.2.1 Flare System

There will be no routine discharge of production hydrocarbons to the flare or vent. There will be a continuous low-level purge of the flare headers and flare tips with hydrocarbon gas to ensure the flare system remains lit in all weather (wind) conditions. Blanket gas for the storage tanks is provided by a marine inert-gas generator.

The flare is sized for the following scenarios:

- Emergency flaring (sequential blowdown),
- Flowline and pipeline depressurisation (normally to manage
- Choke failure.

The flare system consists of an HP and an LP flare system. These systems protect the topsides; they do not provide any pressure protection for the hull. The cargo tanks and other hull storage tanks have a breathing-gas system that will be part of the marine vent system. Short-term flaring is anticipated during start-up, shutdown and some upset conditions i.e. flash gas compressor trip. If an unplanned shutdown of the sub-sea production system is required and the lines are dosed with methanol the system may have to be depressurised to avoid hydrate issues if the plant is not re-started within a given time frame (see section 7.6.1.6 for further details).

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HP Flare System

The preliminary sizing basis for the HP Flare is assumed to be a blocked outlet from the HP Separator and hence relief of 800 mmscf/day, i.e. the max future sales gas flow through the chokes.

The preliminary sizing of the HP flare stack is a vertical height of approximately 95m for this blocked outlet scenario. A sonic flare tip is specified. The size of the main HP flare header is estimated to be 20 in NB and the HP flare KOD is estimated to be 3.5 m diameter x 11 m length. Two HP flare headers are required to segregate wet gas from cold gas and thus avoid the formation of hydrates in the flare headers. The headers terminate in the HP Flare Knockout Drum. This drum separates liquid droplets greater than 300 micron from the gas stream prior to flaring.

The HP Flare Knockout Drum is a horizontal vessel; double nozzle entry may be required to reduce vessel size. The HP Flare Knockout Drum pump evacuates liquids from the vessel under level control to the closed drains system. An electric heater is provided in the vessel to melt ice that may form in the vessel during blowdown or to melt any waxy substances that may deposit.

Currently a vertical flare stack is included in the design. The option for using a cantilevered flare design will be investigated during the next design phase to be in line with security measures dictated by the Israeli MOD. This issue is further discussed in section 11.5.

LP Flare System

One LP flare header is provided. The header terminates in the LP Flare Knockout Drum. This drum separates liquid droplets greater than 300 micron from the gas stream prior to flaring. The LP Flare Knockout Drum is a horizontal vessel without a boot. The pumps operate in duty assist mode. A two out of three voting system is provided with a high level initiating a production shutdown.

7.5.7.2.2 Atmospheric vents and Vapour Recovery

Atmospheric vents are provided for the disposal of non-hydrocarbon vapours which are not suitable for disposal in the flare system due to operating pressure; e.g. open drains system, compressor seal gas vent, diesel tank, chemical storage tanks, compressed air package and nitrogen package. A Vapour Flare Gas Recovery (VRU) system for the FPSO topsides will be provided to recover atmospheric flash gas from the LLP separator. The need for this unit will be reassessed in the next design phase when the purge rates for the flare headers will be reassessed.

7.5.7.2.3 Fuel Gas System

The fuel gas system provides fuel to the gas turbine generators on the topsides. LP fuel gas (for topsides flare purging and pilot burners) will be a secondary level of supply.

The HP fuel gas supply pressure will be between 42 Bar and 30 Bar (depending on final gas turbine selection). Fuel gas supply is taken from three possible locations:

- Off gas from the MP Separator (45 Bar),
- 3rd stage Flash Gas Compressor discharge (80 Bar),
- Sales Gas Compressor suction manifold (80 Bar).

Pressure control valves from each of these sources will be used to maintain fuel gas system supply pressure as demand varies. Staggered PCV set points will be used to preferentially take gas from these sources.

The fuel gas system consists of:

- HP Fuel Gas Super Heater (heating medium),
- HP Fuel Gas KO Drum,
- Fuel Gas Filters,
- LP Fuel Gas KO Drum.

Fuel gas requirements are summarised below.

Table 7-25: HP fuel gas summary

DESCRIPTION	UNITS	INITIAL RUNNING	FUTURE RUNNING	DESIGN ^[1]
Power Generation	mmscf/day	4.0	6.1	9.3

Note: [1] Design rates apply a 10% design margin

The only HP fuel gas users are the power generation turbine. The HP fuel gas system design rate is sufficient for all power generation turbines running simultaneously e.g. during duty/spare changeover. It is assumed that there will be no additional fuel gas capacity installed in the future. The initial fuel gas system design rate includes power generation fuel gas requirements for the full build out to 800 mmscf/day.

7.5.7.2.4 Heating Medium System

A hot-oil based heating medium system will be used. The system will extract energy from two of the power generation turbine exhausts via waste heat recovery units (WHRU). The major heating loads, hot oil recirculation rate and hot oil supply and return temperatures for the FDP case development are shown below.

Table 7-26: Heating medium summary

DESCRIPTION	UNITS	INITIAL RUNNING	FUTURE RUNNING	DESIGN ^[1]
Condensate Heater Duty	MW	1.0	1.0	1.0
HP/MP Interstage Heater	MW	0.7	0.7	0.7
Oil Heater Duty	MW	0.6	0.6	0.6
MEG Regeneration Reboiler Duty	MW	1.0	1.0	1.1
Future Tanin Inlet Heating Duty	MW	0	3.1	3.4
Total Initial Heating Medium System Duty	MW	3.2	6.3	6.9
Initial HM System Hot Oil Recirculation Rate	m ³ /h	105	210	230
Future Tanin Subsea MEG System Duty	MW	0	16.4	18.0
Total Future Heating Medium System Duty	MW	0	16.4	18.0
Hot Oil Recirculation Rate	m ³ /h	0	513	564
Waste Heat Recovery Duty (Power Gen)	MW	3.2	7.0 (22.7)^[2]	7.0 (24.9)^[2]
Hot Oil Supply Temperature	°C	165		
Hot Oil Return Temperature	°C	135		

Notes: [1] Design rates apply a 10% design margin

[2] The number in parenthesis is the required heating duty if DEH is selected as the hydrate inhibition method for Tanin.

It can be seen that heating requirements are modest, unless MEG is selected as the means of inhibition for Tanin or any future field).

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WHRU's will be provided on two of the initial power generation turbines to supply initial and future heating loads. There will be no pre-investment in additional WHRU capacity. If required, the addition of the fourth future power generator could be specified with a WHRU. The FDP case – assuming use of DEH for Tanin – does not require a 3rd WHRU to be installed.

The Heating Medium (HM) system is a closed loop system with an expansion vessel, circulation pumps (2x100%), dump cooler and slipstream filters. Hot-oil heating medium is supplied at 165°C and returned at 135°C.

Heating Medium – Future Scope

Topsides space and tie-ins will be included for a future heating medium system to cater for future MEG regeneration/reclamation heating loads (if installed). This is currently not planned. Tanin hydrate management is discussed further in Section 7.6.7. Other (currently unknown) remote fields may however require MEG to be employed and hence it is prudent to allow for expansion of the Heating Medium system in the FDP design.

7.5.7.2.5 Cooling Medium System

A closed-circuit inhibited-seawater cooling system provides all cooling requirements on the topsides. Warm cooling water is cooled indirectly by seawater extracted from the surrounding sea. The cooling medium and associated seawater system are sized for all initial cooling requirements as well as for the future sales gas compression cooling duty. Space and tie-ins are provided for a future cooling medium and seawater system to provide cooling for a future subsea MEG units, should they be adopted for Tanin or another (currently unknown) satellite.

The Cooling Medium system provides cooling for the process and other utilities. The main consumers are:

- Sales Gas Compressor Aftercoolers, E-27010A/B and future E-27110,
- Flash Gas Compressor Aftercoolers, E-23030, E-23020, E-23010,
- Oil Rundown Cooler, E-21010 (if required),
- Auxiliary systems i.e. compressor lube oil systems etc.

Cooling water is circulated by 3x50% electric motor driven Cooling Medium Circulation Pumps that forward it through the Cooling Medium/Seawater Exchangers (3x50%) in which the heat absorbed from the process is transferred to the sea water stream. The supply temperature of Cooling Medium is controlled at 35°C by a bypass stream around the cooling medium side of the Cooling Medium/Seawater Exchangers. The cold Cooling Medium is fed to the various consumers through a supply header.

The 'hot' cooling medium return (50°C) is collected and returned to the suction side of the Cooling Medium Circulation Pumps through a return header. An Expansion Vessel is provided to cater for thermal expansion of the liquid in the system from the lowest to the highest temperatures.

Cooling Medium Loads

The major cooling loads, cooling water and seawater recirculation rates and supply and return temperatures for the base case development are shown in Table 7-27, along with the future and design duties and rates for 800 mmscf/day sales gas rate.

Table 7-27: Cooling medium summary

DESCRIPTION	UNITS	INITIAL RUNNING	FUTURE RUNNING	DESIGN ^[1]
Oil Cooler Duty	MW	0.4	0.4	0.4
Sales Gas Compressors Discharge Cooler Duty ^[2]	MW	10.0	15.0	16.6
Flash Gas Recompression Coolers Duty	MW	0.7	0.7	0.8

DESCRIPTION	UNITS	INITIAL RUNNING	FUTURE RUNNING	DESIGN ^[1]
Topsides MEG System Cooling Duty	MW	1.0	1.0	1.1
Heating Medium Trim Cooler Duty	MW	1.3	1.3	1.4
Power Generation Gas Turbines Cooling Duty	MW	1.9	2.8	3.0
Compressor Electric Motors Cooling Duty	MW	1.2	1.7	1.9
Total Initial Cooling Medium System Duty	MW	15.9	22.9	25.2
Initial CM System Cooling Water Circulation Rate	m ³ /h	960	1,710	1,880
Initial SW System Seawater Lift Rate	m ³ /h	1,300	2,320	2,550
Future Tanin Subsea MEG Cooling Duty ^[3]	MW	0	17.0	18.7
Future Heating Medium Trim Cooler Duty	MW	0	3.3	3.6
Total Future Cooling Medium System Duty	MW	0	20.3	22.3
Future CM System Cooling Water Circulation Rate	m ³ /h	0	1,260	1,380
Future CM System Seawater Lift Rate	m ³ /h	0	1,700	1,870
Seawater Supply Temperature	°C	30		
Seawater Return Temperature	°C	40		
Cooling Water Supply Temperature	°C	35		
Cooling Water Return Temperature	°C	50		

Table Notes:

[1] Design rates apply a 10% design margin

[2] Cooling medium system is designed for 1 out of 2 initial sales gas compressors running at 100%. If 2 compressors running at 100% is required, it is assumed that spare cooling medium and seawater lift pumps can be utilised to provide the additional cooling load.

[3] Only if MEG Inhibition is selected for Tanin

Cooling Medium – Future Scope

Topsides space and tie-ins will be included for a future cooling medium system to cater for:

- Future subsea MEG regeneration/reclamation cooling;
- Future heating medium trim cooling.

The future cooling medium system is assumed to employ indirect seawater cooling and thus space and tie-ins for a future seawater system are also required. The initial phase cooling medium system will be sized to cater for the future export compression system cooling load.

7.5.7.2.6 Seawater System

Seawater caissons will be used to supply seawater such that a colder temperature can be used in the system design. The caisson will take water from approximately 50m below the sea surface. A seawater system is required to meet the cooling, service water and fresh water maker supply on the FPSO. The seawater system is separate from the ships ballast water system.

Seawater will be lifted (using Seawater Lift Pumps), electro-chlorinated (to treat the seawater of bacteria and marine growth) and coarse filtered (to remove large particulates) prior to being supplied to the seawater distribution system topsides.

7.5.7.2.7 Chemical Injection

Chemical injection is required to manage subsea flow assurance, ensure proper operation of process equipment and protect piping and equipment, as indicated in Table 7-28.

A topside chemical injection package is provided to supply production chemicals. Permanent chemical tanks are provided which are filled from portable tote-tanks using gravity flow.

- Bulk chemical storage and transfer pumps to topsides chemical injection facilities shall be located on the hull, with bulk loading hoses provided fitted with unique hose couplings.

Facilities shall be provided for partial re-supply of bulk chemicals from topsides tote tanks in the event that the hull tanks are unavailable or contaminated.

Chemical injection requirements for effective management of the produced liquids is uncertain due to lack of samples to perform laboratory tests. It is therefore unknown whether anti-scale or demulsifier chemicals will be required continuously or on a batch basis. To allow for this uncertainty spare injection points, pumps, storage tanks will be provided. Their exact use will be determined post start-up when chemical trials can be executed. Further chemical studies will be undertaken pre-FID if samples of analogous fluids can be obtained.

Table 7-28: Typical chemical injection requirements

CHEMICAL	REQUIREMENT	LOCATION
Methanol	Hydrate Management	Subsea Well – start up and planned shutdown
		Subsea Flowline and jumper - shutdown
		Topsides - backup hydrate removal in dew pointing unit
Corrosion Inhibitor	Corrosion Management	At production wellhead
Scale inhibitor	May be required, to be finalised in pre-FID engineering scope	At production wellhead. Could be mixed with corrosion inhibitor.
Biocide (hypochlorite)	To limit marine growth in seawater system	Sea water lift system
Demulsifier	May be required, to be finalised in pre-FID engineering scope	Upstream various separators
Anti-foam	May be required, to be finalised in pre-FID engineering scope	Upstream various separators

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KHI	Hydrate management for future fields. Unlikely to be required if DEH demonstrated to be technology of choice	Tanin subsea injection

7.5.7.2.8 Open and Closed Drains

Three separate drainage systems handle effluent produced from the topsides facilities on an intermittent basis:

- Closed drains – liquids drained from a process system during a planned maintenance activity through a hard-piped connection,
- Hazardous open drains – liquid spills from areas where hydrocarbon liquids could be present,
- Non-hazardous open drains – liquids (normally rain or wash down water) from areas where hydrocarbon liquids should not be present.

Closed drains from the topsides process/utility modules shall be routed to the closed drain tank located below the topsides. Oil recovered from the hazardous open drain systems shall be routed to the closed drain system, via a transfer pump. A slop oil tank is also envisioned to be provided in the hull. Drains philosophies will be further developed during the pre-FID engineering phase.

7.5.7.2.9 Instrument and Plant Air

The instrument and plant air system supplies instrument air for the topsides and hull equipment instrumentation and actuators. Air is drawn from the atmosphere, compressed and dried.

A take-off for the Plant Air system is taken from this dried air stream before the air enters the Instrument Air Receiver. Plant air demand is intermittent and small relative to instrument air demand. The instrument air from the receiver, at 9.3 Bar and 30°C, is distributed to instrumentation throughout the facilities. Air from the receiver is also routed to the nitrogen system for nitrogen generation:

- The topsides air systems will provide sufficient local receiver vessels and headers to ensure the distribution of instrument air and plant air to all topsides systems,
- The compressed air system shall be split in to two systems: -
 - Plant air.
 - Instrument air.

The compressed air supply shall be oil and dust free, with a dew point specification of minus 40°C at the maximum operating pressure.

7.5.7.2.10 Nitrogen System

Dry compressed air is supplied from the Instrument Air Receiver to the Nitrogen Generation Package. Nitrogen with a minimum purity of 95% (v/v) and a maximum of 3% (v/v) oxygen content is typically produced through membrane separators and routed to the Nitrogen Receiver however high purity nitrogen >99% may be required for MEG tank blanketing.

The Nitrogen Receiver supplies nitrogen at 8.5 barg and 30°C to the nitrogen users in the topside facilities and the hull. The largest continuous users of nitrogen in the topsides are the seals of the Sales Gas Compressors and the flash-gas compressor, which require continuous purging while in operation. Other topside users include blanketing of the heating medium expansion drum. A sub-header is taken from the main distribution header to cater for nitrogen supplies to the utility stations.

7.5.7.2.11 Heating Ventilation and Air Conditioning (HVAC) Systems

HVAC will be provided as follows:

- HVAC systems will be provided for the accommodation, working areas, machinery rooms, stores and equipment rooms. The purpose of these systems is to provide fresh air at a managed

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temperature and humidity. Emitted vapours are removed. HVAC can also be used to generate a pressurised atmosphere in confined spaces.

- The main supply shall be 100% fresh air or partly fresh/re-circulated air. This performance shall be achieved with no more than 50% re-circulated air. CO2 monitoring will be performed on re-circulated air.

7.5.7.2.12 Fresh Water Systems

A potable water and fresh service water system will be provided on the FPSO. The fresh/potable water system shall be designed to produce, bunker, store, sterilize and distribute potable water for domestic consumption and general use on the FPSO.

Fresh water shall be generated from seawater using a Reverse Osmosis unit, located in the hull. The fresh water maker shall be sized for minimum 120% design capacity. Potable water will be supplied to the living quarters for drinking water, hot and cold water service. Sea water will be used for flushing of the domestic toilets. Fresh service water will provide make-up for the cooling water system and also supply the safety showers, general utilities, workshops and slop tanks for tank washing.

A storage tank shall be provided for plant service water usage, safety shower requirements and tank washing. It shall be possible to bunker fresh water from supply vessels in case of failure of the FPSO water maker.

7.5.7.3 Control systems

The FPSO shall be equipped with an Integrated Control and Safety System (ICSS) for the monitoring, control and safeguarding of machinery, power management, marine/hull functions, topside process facilities, utilities and subsea equipment.

The main CCR shall be located in either the Living Quarter Module or the Integrated Local Equipment Room Module, and shall be continuously manned. The ICSS shall include the following functionality, which can be monitored from a single Human Machine Interface (HMI): -

- Topsides process control, start-up and shutdown,
- Topsides and subsea wells control, start-up and shutdown,
- Integrated Marine Monitoring System (IMMS), which includes environmental, position (relative and global) monitoring and ballast management,
- Fire and gas detection (FGS) and mitigation.

There shall also be interfaces with the following systems: -

- Power Management Systems (PMS),
- Telecoms,
- Closed Circuit Television System,
- HVAC systems.

The overall ICSS functionality comprises a Process Control System (PCS), a Process Shutdown System (PSD), an Emergency Shutdown (ESD) system and a Fire and Gas System (FGS).

- The PCS shall be responsible for the monitoring and control of process facilities, utilities, regulatory and on/off control, interface with other third party systems and the human machine interface (HMI) located in custom consoles in a Central Control Room,
- The PSD system shall shutdown equipment or systems in response to specific inputs from field instrumentation, the process control HMI in the CCR or local manual shutdown push buttons. A PSD shall be initiated automatically upon loss of control or manually for equipment protection from mechanical damage. The response to a shutdown shall be dependent upon the initial cause,
- The ESD system shall shutdown equipment or systems in response to specific inputs from field instrumentation, ESD functions on the HMI in CCR, FGS, or field manual ESD push buttons. The ESD system shall be separate from the PCS and the Fire and Gas system that are also integrated within the overall ICSS.

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The ESD shutdown logic shall have five levels:

- Level 0: ESD Abandon Facility,
- Level 1: ESD Facilities Shutdown,
- Level 2: PSD Total Process Shutdown,
- Level 3: PSD Train Process Shutdown,
- Level 4: PSD Local equipment or system shutdown.

A Level 1 shutdown shall allow for the blowdown of the process plant in response to fire and gas detection. An ESD Level 1 shall automatically initiate all lower level PSD Level 2, 3 and 4 shutdowns to prevent cascade action. A Level 0 shutdown shall be initiated by the Offshore Installation Manager (OIM) by pushbutton in CCR or at the TR/lifeboat station. A Level 0 can only be initiated following a Level 1 shutdown on the judgment of the OIM. A Level 0 shutdown shall perform all Level 1 actions and shall initiate an automatic blowdown of the production facilities. Emergency communication facilities shall be maintained in an operational state throughout an emergency to support the emergency response plan.

A common fire and gas system shall cover the entire FPSO and will comply with European Regulatory Requirements. The FPSO fire and gas system shall be capable of functioning as a self-contained system, as required during the transit and integration phases. The system shall be fully integrated between the hull and topsides system after integration of the topsides, such that accommodation and machinery space HVAC vents shall be closed down on detection of gas or smoke.

Remote condition monitoring systems shall be provided for the following major equipment items, to allow vendors to check the condition and status via satellite communications systems:

- Power Generation Systems,
- Main Compressors,
- Flash Gas Compressors,
- Large Pumps,
- Large Electric Motors,
- ICSS,
- Power Management System.

High Integrity Protective Systems (HIPS) are instrumented protective systems, which may be used on the Karish and Tanin developments to: -

- Eliminate a particular overpressure scenario,
- Eliminate the need for a particular relief device,
- Provide system over-pressure protection where a relief device is ineffective,
- Reduce the probability that several relief devices will have to operate simultaneously, thereby allowing for a reduction in the size of the disposal system,
- Reduce the demand rate on a relief device consequently reducing the risk.

7.5.7.4 Telecommunications

There will be data communication between the FPSO, DVS and the Energean Israel offices. The technology choice between satellite systems, fibre optics or point-to-point radio links will be made in the pre-FID engineering phase and once there is more clarity on the bandwidth requirements.

Energean will include bandwidth requirements for maximising the use of remote diagnostics for critical equipment by OEM specialists. This will help minimise the need for non-routine personal transfers to the FPSO and as such help minimise OPEX.

Table 7-29 provides a high-level overview of the technologies that will be considered.

Table 7-29: Telecom technology considerations

Transmission Media	Main Advantage	Main Disadvantage
Microwave line of sight	Low cost equipment, high capacity, high reliability	Requires line of sight, limiting distances to approximately 30 km
Troposcatter	High capacity, high reliability, no delay, IP based system, no recurring monthly costs	Equipment cost is higher than microwave and VSAT, but lower than undersea fiber
VSAT	Low equipment cost, most economical for low capacity (512 Kb/s or less)	Absolute delay (latency), availability degradation (outages), monthly transponder lease cost
Undersea fiber	Highest capacity, can serve many platforms in an entire oil field or basin	Highest installation and restoral cost of all media. Installation cost is typically estimated at more than US\$10 million per 100 km

Transmission Media	Equipment Cost	Recurring Cost	Capacity
Microwave radio, line of sight	Low	None	High
Troposcatter	Medium	None	Medium
VSAT	Low	Monthly lease cost depends on capacity	Low
Undersea fiber	High	Generally a monthly recurring cost for standby restoral services in case of cable break.	Very high

Transmission Media	Distance	Characteristic	Capacity
Microwave radio, line of sight	Short, approximately 30 km (dependent upon terrain)	Cost is relatively insensitive to distance, small cost increase for antennas and towers as distance increases	High, OC-1, 52 Mb/s or higher
Troposcatter	From line of sight (30 km) up to approximately 250 km	Small increase in cost with distance due to larger antennas and increased power for longer distances	Medium, 22 Mb/s
VSAT	Anywhere in a satellite transponder footprint	Insensitive to distance	Low 256 Kb/s typically up to 8 Mb/s, limited by transponder lease cost
Undersea fiber	Distance is typically not a limiting factor.	Acquisition cost is proportional to distance, relatively insensitive to capacity, recurring cost for standby restoral service for cable breaks	Highest capacity, multiple STM-1, 155 Mb/s

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7.5.8 Dry-gas pipeline to shore

7.5.8.1 General requirements

The Karish and Tanin dry-gas pipeline covers both Israeli land, territorial waters (up to 12 nautical miles offshore) and the Israeli Exclusive Economic Zone (beyond 12 miles from shore).

National Outline Plan 37/H (i.e. TAMA 37/H, Hebrew acronym for Tochnit Mit'ar Artzit), details the Israeli Government's environmental and social requirements for the area where the Karish and Tanin development project will be executed. The dry-gas pipeline will land at a defined "Northern Array" in the region of Dor on the northern coast of Israel.

The envisaged pipeline is 24"/30" NB with a 1mm corrosion allowance. To avoid the implications of low pressure specification breaks, the line is designed for a pressure of 150 barg from the top of the riser at the FPSO to the last valve at the tie-in point with the existing INGL transmission system. The design code for the pipeline system is DNV-OS-F101, including the onshore part from CSV to DSV.

Energean has undertaken discussions with INGL regards the nature and position of an "interface facility" in shallow water that would allow 3rd party gas suppliers to transport dry gas through this section and into the INGL transmission system without need for an additional beach crossing. In this FDP Energean allows for an increase in pipeline diameter to 30" (from approximately 15km offshore) and a tie-in point (two valved T's with intermediate full-bore ball valve) at 10km where a future INGL owned gathering manifold or platform could be installed. Theoretically this could be installed with the pipeline by Energean on behalf of INGL. Alternatively it could be installed later when details of 3rd lines are known.

In the maritime zone, TAMA 37/H requires the pipeline to be buried to a depth of 1.2m in any area where it is at a water depth shallower than 60m. For the shore approach: *"the engineering design of the landing point of the pipeline to the coast shall include, where possible, an underground passage which will prevent harm to the coastal cliff and exposed kurkar rock at a depth of up to 10m below the surface of the sea"*. For these reasons, an HDD shore approach and beach crossing is planned. It is noted that the existing pipeline (INGL) and future lines in the same region (Noble Leviathan) used, or will use, HDD and micro-tunnelling shore crossing methods respectively.

7.5.8.2 Deep water section to 10km sub-sea "interface facility"

The dry-gas pipeline will transfer sales gas from the FPSO to the delivery point. An interface with an INGL owned and operated system is contemplated at a point 10 km from the shore (where a sub-sea manifold may be installed in parallel with the Karish development or at a point in the future). The delivery point will be at this location. Fiscal metering will therefore be undertaken at the FPSO to avoid the need for installing a sub-sea metering skid. This would have significant cost and operability issues.

This system was introduced in Section 7.2.3. It will initially consist of 1 x 16" NB riser, tied-in in to a 24" NB subsea pipeline. A second 16" NB riser will be installed in a later phase to expand capacity from 650 to 800 mmscf/day. The pipeline is designed for 150 barg from the top of riser at the FPSO to the DVS without a design pressure break. It is envisaged that the line will transition to 30" as it passes onto the continental shelf, possibly 15km from the coast.

The gas export SSIV substructure contains the following:

- Connections from the 16" NB riser bases,
- Connection to the export pipeline PLET by a piggable spool,
- Pig launcher/receiver connection to be used during commissioning.

The gas is dry and predominantly methane; corrosion rates are calculated to be minimal. Regular pigging is not required to manage pipeline integrity. Intelligent pigging is required on a 5-yearly basis by the Israeli Natural Gas Authority to demonstrate continued integrity of gas transmission lines. A pig launcher/receiver connection is provided on the SSIV skid to provide this functionality.

The pigging philosophy for the dry-gas pipeline will be as follows:

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- No regular or planned maintenance pigging (scraping, clean, batch corrosion treatment),
- Provision for 5-yearly intelligent pig runs if confirmed necessary by the Natural Gas Authority.

Via discussions with various providers of intelligent pigs it has been concluded that the proposal to increase the line size in the shallow water section (from around 15 km offshore) to 30" is feasible. A number of providers have intelligent pigs that can accommodate a line size change of this magnitude. Theoretically an increase to 32" could also be accommodated although this would require the development of a new intelligent pig. A transition to 30" is therefore currently assumed. Use of a 32" diameter could be revisited should INGL want to develop an appropriate intelligent pig. Cleaning pigs (for use during line commissioning) are also available for such a telescopic arrangement as long as the transition area is designed appropriately.

7.5.8.3 10km sub-sea interface (manifold)

As outlined in section 7.2.3 and discussed above, Energean and INGL have discussed the possibility of including in the Karish dry-gas pipeline a "facility", installed approximately 10 km from the coast in a water-depth of between 60 and 100m, that would allow 3rd party dry-gas producers to access the coastal section of the Karish dry-gas line in the future. This would avoid the need for further beach crossings to be undertaken at Dor. The Israeli government has proposed that the coastal section of the Karish pipeline should be funded by the state and owned and managed by INGL. This effectively extends the existing INGL gas transmission system 10 km offshore. The location being considered for this interface "facility" is as proposed in TAMA/37/H and shown in Figure 7-57 .

A number of different options for this interface "facility" have been considered. The option presented in this FDP has been agreed between Energean and INGL. It is outlined below. It appears possible that the line size selected for the Karish dry-gas pipeline (24" NB) could be increased to either 30" or even 32" NB at a point on the continental shelf. As INGL wishes to ensure that the fully-built out capacity of the shared coastal section is approximately 1,430 mmscf/day without reducing the capacity of the Karish section below 800 mmscf/day, such a line-size change could be advantageous. Alternatively a 24" NB could have been employed and the design of the Karish sales-gas compressors modified to allow discharge pressures up to 150 bar (the rating of the proposed pipeline).

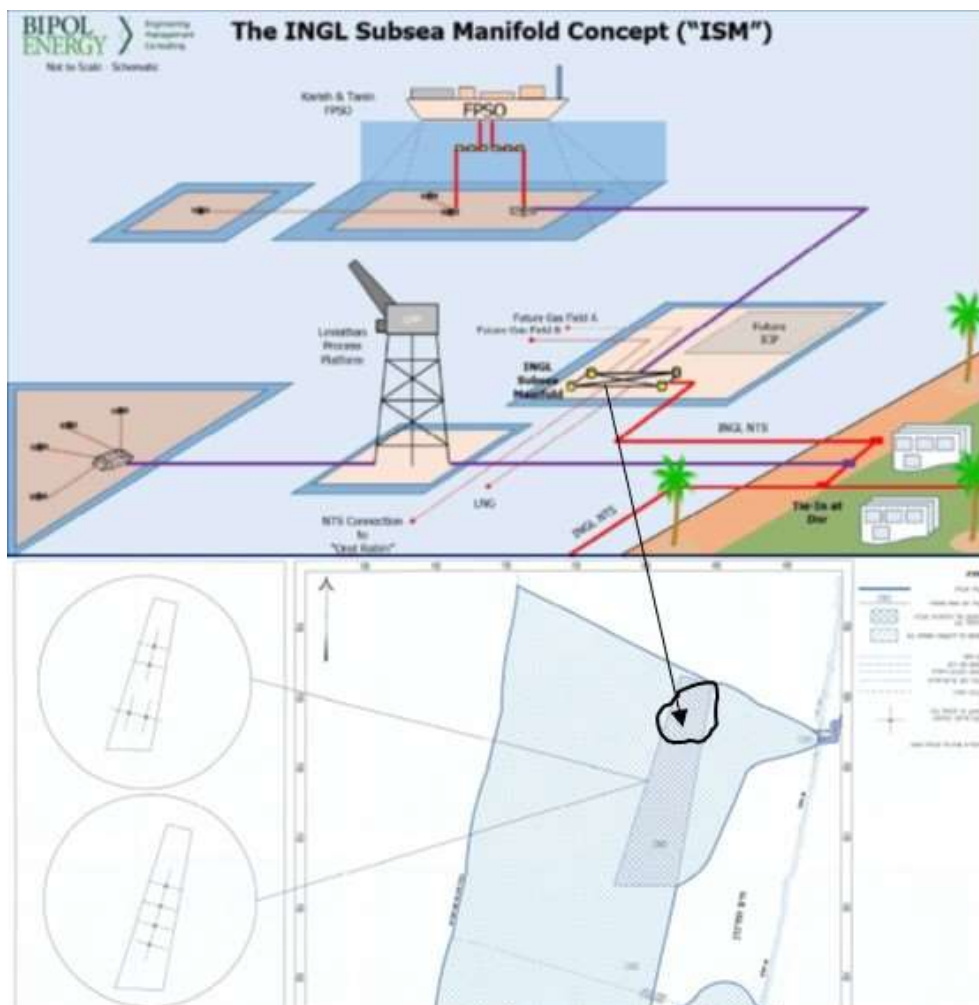


Figure 7-57 INGL Subsea Manifold concept (ISM)

The cost estimate included in the current FDP assumes no manifold is installed in parallel with the Karish development project, i.e. Energean installs a stand-alone 24"/30" NB pipeline from the Karish FPSO to DVS. Only the two T-pieces and the block valve at 10km are installed at this time. Clearly if required by INGL, Energean would manage the installation of the 3rd party manifold in parallel with the dry-gas pipeline, using its mobilised contractor and installation vessels. The cost estimate is relatively insensitive to the exact position of the 24" to 30" transition or indeed whether eventually a 32" near shore line is selected.

7.5.8.4 Shore approach and beach crossing

TAMA 37/H provides the regulatory framework for the permitting sequence of the shore approach and onshore works. Obtainment of these permits is an essential element for the success of the upstream development and will be undertaken in advance and managed by an experienced Israeli local team. For the Karish and Tanin Development, Horizontal Directional Drilling (HDD) has been selected for the required beach crossing of the 30 (or 32") dry-gas pipeline. Hence the plans covered by the current FDP are fully compliant with article 6.4.C of TAMA/37/H.

An HDD shore approach requires an over-sized, and sometimes cased, borehole to be drilled in a catenary from a point onshore to a predetermined point offshore. The pipeline is then typically installed through the borehole by either pulling or pushing. HDD is commonly used when the foreshore area is rugged (e.g. cliffs are present), access to the foreshore is limited, or there is a need to minimise the disturbance to the foreshore, beach and/or nearshore environments. At Dor it is this latter issue that is the driver for use of HDD. Access to the coast is simple and the beach crossing executed via the trench and causeway methodology. Dor beach

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however is located close to tourist facilities and in the near shore section hard rocky outcrops, important with regards to environmental diversity, have to be avoided. An HDD approach is therefore required.

7.5.8.4.1 Horizontal Directional Drilling (HDD)

Horizontal Directional Drilling is a steerable, trenchless, method of installing underground pipes, conduits and cables in a shallow arc, along a prescribed bore path by using a surface-launched drilling rig, which has minimal impact on the surrounding area.

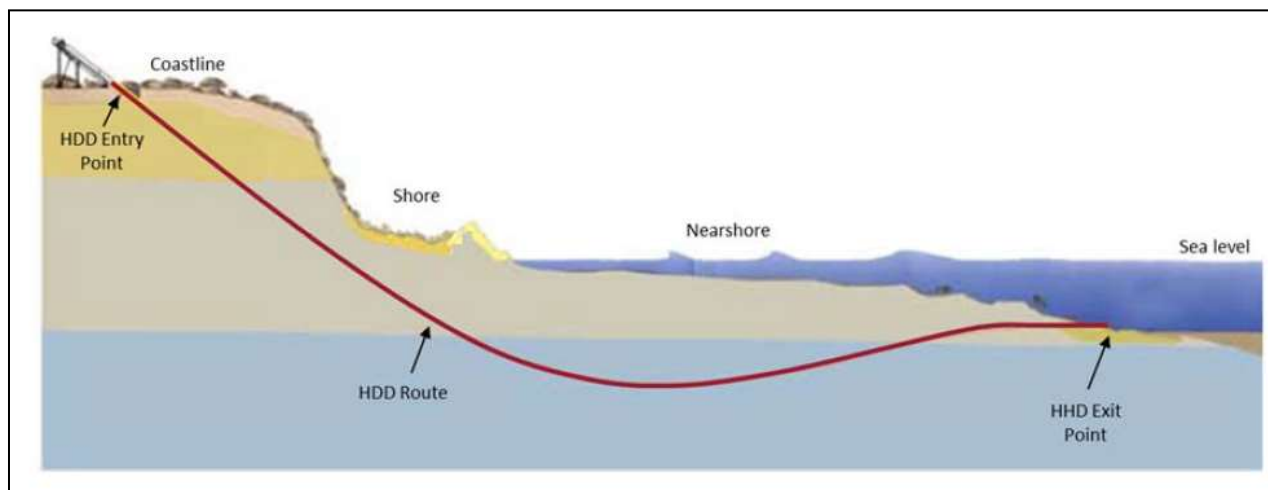


Figure 7-58 Schematic of a typical HDD shore approach

A borehole will be initiated at an onshore location, close to the planned location of the CVS, and progressed in a catenary to a point where it breaks the seabed at a precise and predetermined position at an approximately horizontal attitude. The length of the borehole is dependent on the HDD drilling equipment used plus the stability of the ground at the exit location. At present, the HDD length is assumed to be 2.5km, but this shall be defined during the pre-FID engineering phase in conjunction with local HDD subcontractors.

Micro-tunnelling, for the Noble Leviathan pipelines, will be performed in February 2018, according to current Noble Energy plans. Possible synergies could be envisaged to share mobilisation costs of the boring machine. However Energean currently envisages use of HDD and not micro-tunnelling. It may also not be possible for Energean to obtain all necessary permits to allow it to execute its work immediately following completion of the Noble Leviathan beach crossing.

After the HDD borehole is completed, the pipeline will be passed through it. This can be achieved by pulling a pipeline laid offshore by a shallow water barge through the bore hole with a winch placed onshore. Alternatively, the line can be fabricated onshore and “pushed” through the borehole where it is picked up by the shallow water barge. The most optimal approach will be identified as the project development progresses. The cost estimate included in the FDP assumes the line is pulled from offshore to onshore. This option probably is the most conservative.

Post-trenching of the pipeline will be performed as required by on-bottom stability analysis and the TAMA 37/H. Any pipeline expansion seen at the end of the offshore and onshore pipeline is lost in the buried soil. Therefore, no requirement for an anchor block is currently envisaged.

7.5.8.5 Coastal Valve Station expansion

The Coastal Valve Station (CVS) developed by Noble for the Leviathan project will be expanded by Energean. The location and layout of the CVS has been defined with TAMA/37/H. Locations for three different entities – INGL, Leviathan and “Future supplier” – are identified. The Karish dry-gas line will occupy the most northerly segment of the CVS (i.e. “Future supplier”). The two Noble pipelines (gas and liquids respectively) will occupy the central segment and the INGL line the southerly one. This sequence ensures that no pipeline crossings

are required ahead of the CVS as the Karish line approaches the shore from a more northerly location than the Leviathan lines. It is also logical that Noble installs their lines and valves ahead of those for Karish.

The CVS will be located in land-cell 210 about 450m from the shoreline. This is illustrated below. This figure is extracted from TAMA/37/H.



Figure 7-59 Onshore locations

The CVS will consist of the following items:

- Electrically actuated isolation valve with 6"/8" bypass (details as per TAMA/37/H),
- Manual valves and bypasses,
- External power and communications links to the control centre,
- Venting facility.

The CVS is shown schematically below.

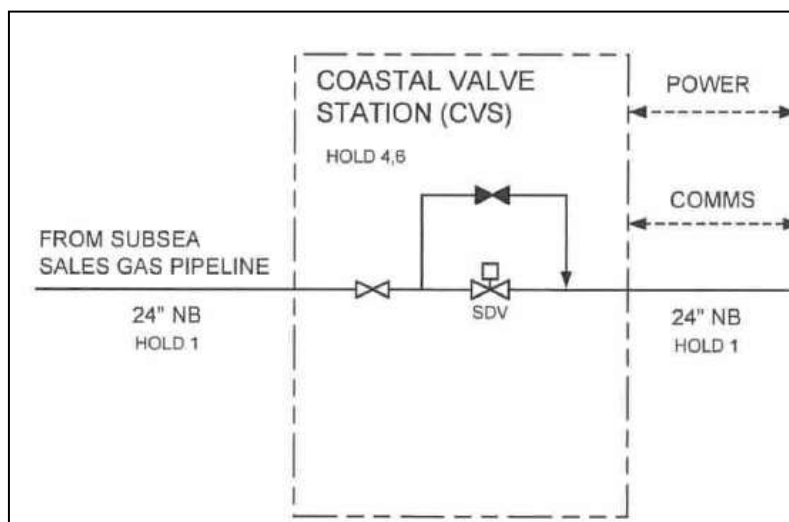


Figure 7-60 CVS schematic

A general layout. Also extracted from TAMA/37/H, is provided in Figure 7-61. The northerly, unlabelled segment, is reserved for the Karish line.



Figure 7-61 General layout at CSV location

The Existing INGL pipeline is indicated in green and future Noble Leviathan pipelines in bold orange and pink.

7.5.8.6 Onshore pipeline

The routing of the onshore section is shown in Figure 7-62.

The onshore dry-gas pipeline will be approximately 1.5 km long and will connect the CVS to the DVS through a corridor previously delineated by TAMA/37/H. The pipeline will be buried for the entire route between the 2

stations, maintaining a cover of 2m over the pipe as required by TAMA/37/H. It will have two major crossings: the Haifa-Tel Aviv railway and the Coastal Highway 2. These will be drilled.

The two Leviathan pipelines will also be run between the CVS and an extended DVS. The Energean pipeline will be located at an agreed distance from the more northerly of Leviathan's two lines.



Figure 7-62 Available laydown and staging areas onshore Dor

Energean will construct an extension to the existing INGL Dor Valve Station. An area of land to the south of the existing DVS has been allocated. Between this area and the existing DVS, INGL will fabricate a new manifold into which the Karish and Leviathan gas supplies will feed. Noble will build the reception facilities for Leviathan to the immediate north of the existing DVS.

In the Energean DVS-extension, facilities for pigging, metering, flow/pressure control and (if necessary) heating of the dry-gas will be installed.

As a result of Energean having been allocated the southerly site at the DVS and Noble the northerly site the Karish and Leviathan pipelines will have to cross between the CVS and the DVS. Energean is discussing the best location and design of this crossing. Details will be firmed up in the next phase.

TAMA/37/H provides the regulatory framework for the permitting sequence for onshore works. Obtainment of the permits is an essential element for the success of the upstream development and will be developed in advance and managed for Energean by an experienced Israeli local team.

7.5.8.6.1 Corrosion Cathodic Protection

The primary barrier against external corrosion for the Karish dry-gas pipeline will be a high-integrity 3LPP line pipe coating. This will be supplemented by cathodic protection (CP) with a permanent impressed current cathodic protection (ICCP) system for the onshore section.

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Monolithic isolation joints will be installed at each end of the onshore pipeline to isolate the pipeline ICCP system from:

- The Dor valve gas station and INGL pipeline CP system on one side,
- The offshore pipeline sacrificial anodes CP system on the other side.

7.5.8.6.2 Onshore Installation

The onshore 30" gas export pipeline from CVS to DVS will be installed using the single/multiple spread open-cut method. In this case a trench is opened and the pipeline is installed inside the trench. After backfilling, the pipeline will be integrity tested. If casings for the pipelines are to be used, then the pipeline casings will be installed first with the carrier pipe installed inside the casings. The pipeline is held inside the casing with spacers, which are typically a minimum of 1m apart.

The equipment that will be required to perform the onshore pipeline installation are:

- Pipe Transportation and Handling Equipment: for example pipe haulage trucks to transport the coated line pipe from the storage yard to the Right Of Way, pipeline lifting (or roll) cradles to handle the pipe, horizontal rollers that are useful for pulling pipes into road crossings,
- Pipe Preparation Equipment: a pipe facing (or bevelling) machine to machine precision bevels with the required accuracy for manual or automatic welding, a pipe bending machine used to make cold field bends in pipe to allow for changes in grade and terrain types,
- Pipe Welding Equipment: Internal Pneumatic Line-up Clamps to align two pipe joints for external welding; mechanised welding machines (although traditional manual stick welding may be used, mechanised welding machines enable various degrees of automation of the girth welding process. The degree of automation that is economically efficient depends on the specifics of the project, i.e. pipe length, number of pipelines, diameter and wall thickness of pipe, availability of qualified personnel and schedule),
- Field Joint Coating Equipment: blasting / cleaning and pre-heating equipment;
- Trenching, Lowering & Backfilling Equipment: excavator, pipe layers (with side boom), track-type tractors (or bulldozers);
- Tunnelling/boring machinery: to enable the crossing of the road and railway lines with minimal disruption.
- Utilities and Support Equipment: air compressor, Hydraulic Power Unit, welding power supply.

Where possible, all pipeline construction activities will take place using existing roads and tracks created by either Noble or INGL when earlier pipeline were installed. This will significantly reduce further fragmentation of the natural habitat and provide ease of access for construction vehicles and personnel to and from the construction ROW.

The areas dedicated to storage and staging are shown in Figure 7-62.

7.5.8.7 Dor Valve Station expansion

The facilities to be provided at the CVS and DVS are summarised in the below figure:

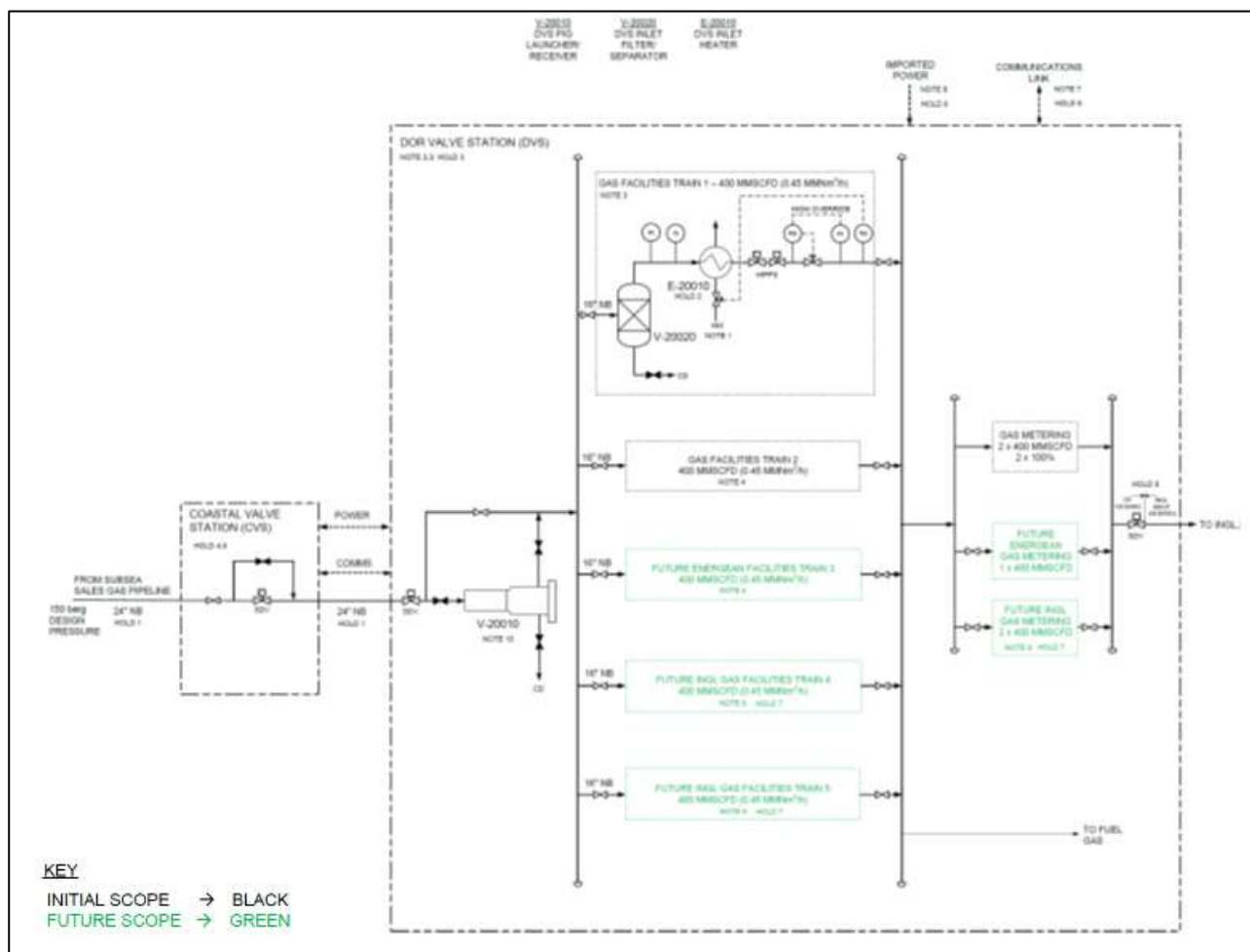


Figure 7-63 Dor Valve Station facilities

The DVS will normally be operated as an unmanned facility. There will be facilities to enable intelligent pigging, although it is not expected to be a frequent or regular requirement.

The gas will be routed through a number of parallel trains which can be expanded in line with the capacity through the plant. Initially 2 x 100%, 400 mmscf/day trains will be installed with space for an additional 3 400 mmscf/day trains to cater for Energean expansion and 3rd party requirements up to a total capacity of around 1,430 mmscf/day. Each train allows for flow/pressure control and heating of the sales gas such that the delivery temperature, after pressure let down, is above the minimum required temperature of 5°C at the INGL tie-in. The need for heating will be confirmed with INGL based upon dynamic simulation work currently ongoing. This work will define the maximum allowable pressure upstream of the DVS FCV (PCV) to avoid settle out pressure above 110 Bar.

Fiscal metering will be performed offshore at the FPSO. Metering runs are provided onshore to control flowrate into the INGL system and hence the pressure (and available line-pack) in the Karish dry-gas pipeline. A number of parallel metering trains are required to cater for turn down and maintenance/calibration.

The new facilities are designed for a pressure of 150 barg so there are no pressure breaks in the process routing. A HIPPS system will be provided to protect the downstream INGL network from over pressure. The HIPPS trip pressure will be determined during FEED.

Utility systems are provided to support the operation of the DVS. This will include a maintenance vent which will share either the existing INGL vent tower or a new unit for Noble Energy's Leviathan Development. Vented volumes are minimal, the vent only being used when pigging operations occur or when metering/heating trains have to be depressurised for maintenance.

A preliminary layout of the onshore DVS facilities is shown in Figure 7-64. This will be updated as the design definition evolves.

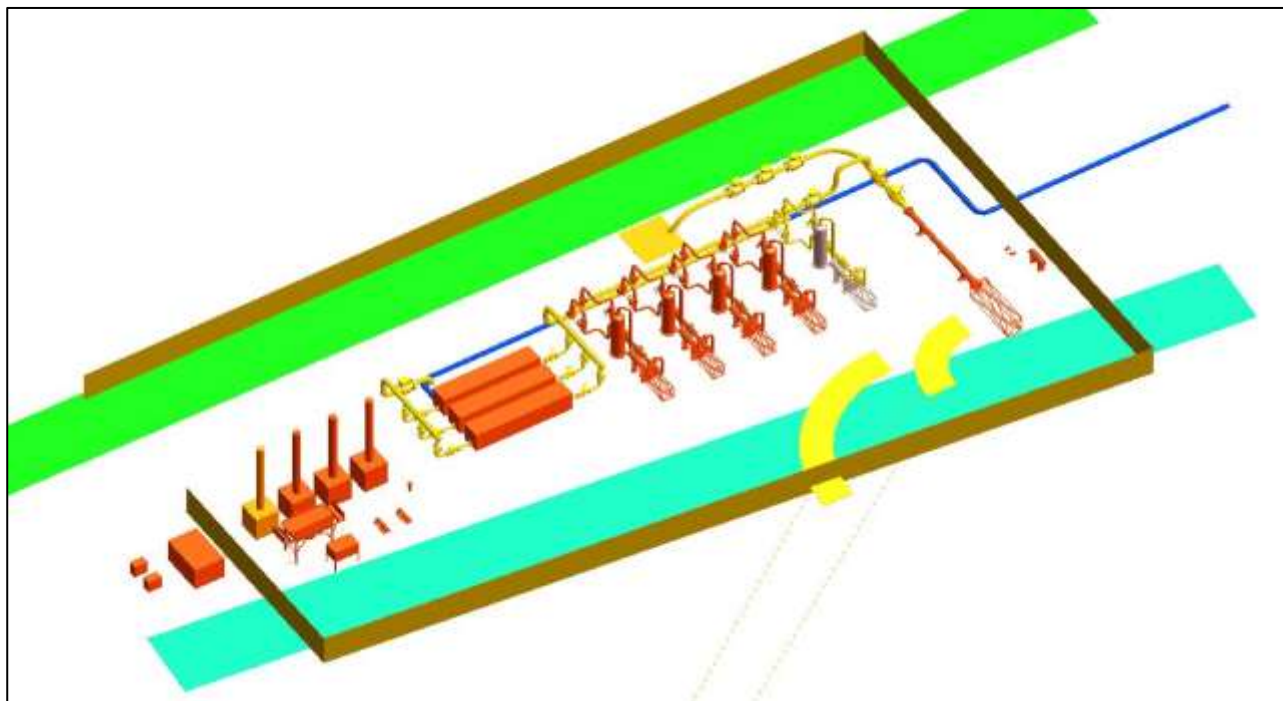


Figure 7-64 Preliminary DVS Layout

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7.6 Operational Considerations

This section provides an overview of some of the Operational issues taken into account in the Karish and Tanin facilities design. Section 10 provides an overview of how the constructed assets will be operated including a detailed Operating Philosophy (Section 10.1). The operational issues discussed in this section will eventually be covered by Operational Procedures developed prior to start-up.

7.6.1 Karish Flow Assurance and hydrate management

Flow Assurance has been investigated for the Karish infield pipeline to design a system capable of producing over the defined production range in a manner that avoids the regular formation of hydrates. This work underpins Energean's decision to employ a hydrate management strategy for the Karish Main (and Karish North) fields based on insulation and residence time. This analysis has also investigated line-sizing, liquid inventory management, cooldown, depressurisation as well as hydrate prevention.

7.6.1.1 Recommended Line Sizes

The recommended line sizes for the Karish infield are as follows:

- Dual 10" NB LWSCR from the Karish manifold to the FPSO. The LWSCRs are sized such that each can transport 400 mmscf/day from 2 wells located at the Karish Main manifold (i.e., any two of KM-1, KM-2 or KM-3),
- A single 8" NB flowline from the KN-1 well to the Karish Main manifold. The flowline is sized so that 200 mmscf/day can be produced from KN-1 when it is tied-back to the FPSO via the Karish Main manifold via one of the dual 10" NB LWSCRs.

The flowline sizing has accounted for a produced water rate of 5 bbl/mmscf and assume a minimum FPSO arrival pressure of 200 barg. The sizing has also been performed such that the system can produce at a required minimum rate of 200 mmscf/day without unstable flow behaviour.

7.6.1.2 Thermohydraulics

Steady state arrival conditions at the FPSO are such that the arrival temperature is above the hydrate formation temperature, based on insulation (overall U value of 3.7 W/m²/°C) and expected normal operating and turndown conditions.

7.6.1.3 Hydrate Formation

Hydrate formation conditions for Karish and Tanin are summarized in the figure below, with a 3°C margin.

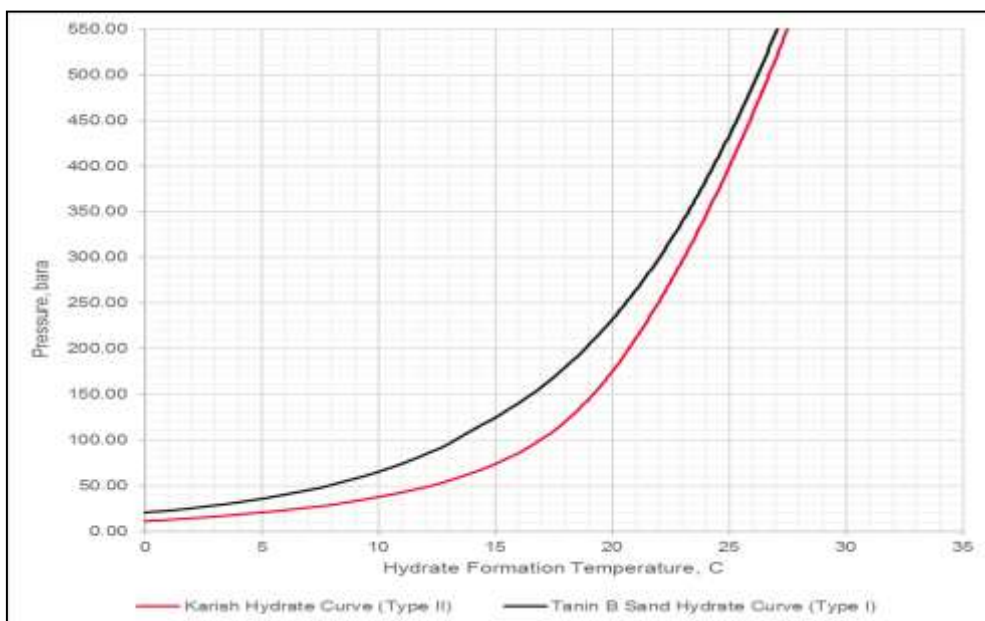


Figure 7-65 Hydrate appearance curves

7.6.1.4 Slug Volumes

A slug volume of 5m³ has been allowed for in the design of the HP Separator and is based upon ramp-up from 200 mmscf/day to 400 mmscf/day per riser and ramp-up from 67 mmscf/day to 200 mmscf/day for the KN-1 well.

These slug volumes have been based on the change in the steady-state liquid hold-up (i.e., the total liquid inventory in the system) that results from a ramp-up operation.

7.6.1.5 Cooldown

Cooldown durations are the amount of time after a production system shut-in that it takes for the hydrate temperature to be reached. The results incorporate a +3°C margin added to the hydrate dissociation temperature. The minimum cooldown durations that have been identified for each flow path are as follows:

- 11.5 hours for a single 10" NB LWSCR from the Karish manifold to the FPSO based upon a total flowrate of 200 mmscf/day being produced from 3 wells, and;
- 11.2 hours for KN-1 flowing to the FPSO based upon 200 mmscf/day being produced from the KN-1 well.

The results are based upon the assumption of no produced water (worst case) and with a wet insulation level of 3.7 W/m²K; this value represents the current limits of what is possible with wet insulation on pipelines, spools, trees and risers.

The cooldown duration is the time after production cessation when the valves at the wellhead and the LWSCR outlet close simultaneously. Additional analysis has been performed where production stops due to a wellhead valve closure, but the valve at the LWSCR is not closed until the riser pressure falls to 200 barg. This revised shut-in sequence has a nominal benefit for the Karish Main manifold to FPSO flow path, - extending the cooldown duration by 0.2 hours. The benefit is more pronounced for the KN-1 to FPSO flow path, extending the cooldown duration by 4.1 hours.

The cooldown durations for both flow paths are longer than the nominal 6 hours "no touch time" requirement and therefore support the selection of insulation and depressurisation as the hydrate prevention strategy for the Karish accumulation (discovered and prospective).

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7.6.1.6 Depressurisation

Depressurisation durations are based upon the amount of time after a depressurisation orifice opens that it takes for the target pressure to be reached. The proximity of the pipeline to the hydrate region has also been assessed when considering the viability of depressurisation. The depressurisations durations and proximity to the hydrate region that have been identified for each flow path are as follows:

- 4.0 hours for a single 8" ID (10" NB) LWSCR from the Karish Main manifold to the FPSO,
- 6.7 hours for the KN-1 to FPSO flow path (with 8" ID flowline and 8" ID LWSCR)

The results are based upon 200 mmscf/day production from a single well prior to shut-in, with depressurisation commencing 6 hours after the "no touch time". The results are based upon a WGR of 5 bbl/mmscf and a wet insulation level of 3.7 W/m²K.

The results indicate that under these constraints both flow paths can be depressurised in less than 7 hours, with at maximum encroachment of the +3°C margin applied to the hydrate dissociation curve of 1.5°C. Thus, these results again indicate that wet insulation and depressurisation is a viable hydrate prevention strategy for the Karish production system.

7.6.1.7 Hydrate Prevention Strategy

The recommended hydrate prevention strategy for the Karish infield system is to thermally insulate the subsea production system to keep the produced fluid temperature outside the hydrate formation area during production. In case of an unplanned long-lasting shutdown, the production system needs to be depressurised to avoid hydrate formation.

In the event of a planned long-lasting shut down of one of the Karish Main manifold elements, the required methanol volume to flush through the spool and manifold branch pipe is estimated to be 0.9 m³. In addition, it is recommended to inhibit the Xmas tree/well upstream of the injection point between the Production Master Valve and the Production Wing Valve. The recommended volume is less than 0.5 m³ methanol/well. This results in a total volume of 1.4 m³ per well.

7.6.2 Karish field pressure profile

As discussed in section 6, the Karish Main reservoir is expected to have good aquifer support. Based on a 3 BCM/year offtake rate, the reservoir pressure is expected to only decline by end field life by 100 bar, from 540 down to 450 bar. As a result the well deliverability at 300 bar back pressure for instance, only reduces from 290 mmscf/day to 190 mmscf/day, i.e. by about 35%, over the field life time. The wells are therefore expected to remain at high pressures and producing with high energy for the duration of production.

The basic production philosophy envisaged is to line up all available wells with fully open subsea chokes and control total flow the FPSO topside riser choke. Individual well chokes can be used to trim production in order to manage offtake in line with envisaged recoverable reserves per well. Choking at the FPSO minimises pressure drops (hence temperature drops) in the sub-sea infrastructure. It also minimises wear to the individual well chokes.

This will result in high pressure drops (particularly in the years after start-up) over the FPSO choke. This will require specialised chokes with hard internals. Noise minimisation/protection should be carefully anticipated during the design.

Methanol injection upstream of the Topside chokes will be necessary to prevent hydrate formation downstream during warm-up periods following a shutdown.

7.6.3 Control Strategy

The following high-level schematic shows the control strategy of the FPSO topside facilities, namely:

- Flow control at both inlet and outlet of the system,
- A series of pressure controls internally within the facilities.

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The export compressors are equipped with variable speed electric motors giving good turndown performance. The main gas/gas heat exchanger in the dew pointing system is provided with a bypass to modulate temperature at the LTS separator. The dual riser system provides good turn-down when operations are restricted to a single riser.

Effective utilisation of the line pack in the 24"/30" dry-gas pipeline to shore will be critical. This should allow the flow rate entering from the sub-sea production system to be disconnected from the flow being transferred from the 30" dry-gas line into the INGL transmission system. It is envisaged that sales volumes will be higher during the day than at night. If possible a stable extraction rate from the producing reservoirs is required to maximise sweep efficiency. Hence at night it is envisaged that the pressure in the 24"/30" pipeline will rise as production exceeds sales. Conversely during the day the pressure in the 24"/30" line will fall as sales exceed production.

As flow and pressure in the 24"/30" dry-gas pipeline changes the discharge pressure of the sale-gas compressors will vary by modulating the speed via the electric motors. The compressor suction pressure will remain constant as will the pressure in the FPSO inlet HP separator. Hence stable conditions will be maintained in the dew-pointing system.

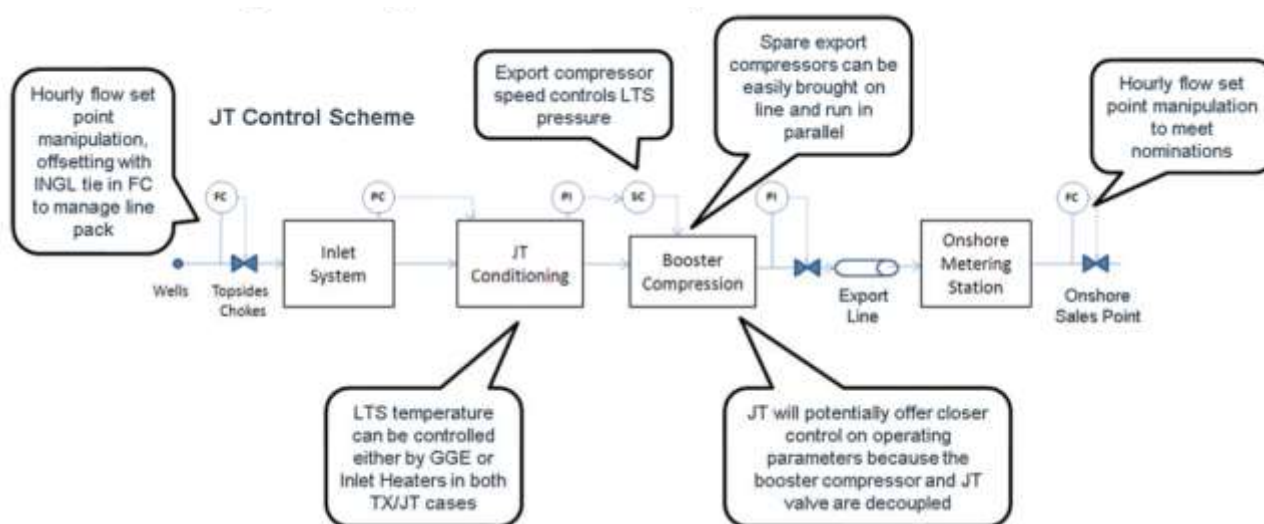


Figure 7-66 Overall FPSO control strategy

7.6.4 Interface with INGL system and dry-gas export line pack management

It is envisaged that the Karish and Tanin fields will be “flow providers” into the Israeli domestic gas grid. Flow from the Karish dry-gas pipeline at Dor will be maintained as constant as possible. Other suppliers into the INGL transmission system will deliver/maintain “pressure” in the northern area and hence will be subject to more swing as demanded when the transmission system fluctuates in pressure. INGL indicate that the pressure at Dor, though it can theoretically vary between 60 and 80 bar, will likely be closer to the upper limit at most times. This will constrain the volume of line-pack available in the Karish dry-gas pipeline as its maximum pressure is restricted to <110 bar as required in TAMA/37/H.

The line pack available will therefore be limited to about 30 bar, which equates approximately to 1mmSm³ or 35 mmscf. This is a relatively modest quantity, representing about 12% of the daily design throughput. It should however be sufficient to allow Energean to manage daily supply variations with having to make large changes to well production rates.

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7.6.5 Export product off specification management

7.6.5.1 Gas Export

The primary specifications are hydrocarbon and water dew points. The key variables in the sales gas contract will be monitored (hydrocarbon and water dew points, calorific value etc.).

The operator response will depend on the extent and the nature of the excursion. If the water dew point is constantly exceeded, then there is a risk of water condensation in the export pipeline and a risk of extra corrosion. In conjunction with a risk based approach, this would dictate the requirement and frequency for intelligent pigging.

7.6.5.2 Oil Export

Primary specifications are TVP/RVP and BS&W. The key variables in the oil export contract will be monitored as crude is moved from the dehydration tanks to the polishing tanks and then from the polishing tanks to the cargo tanks. In the event of oil in the polishing tanks exceeding the TVP or RVP specification, the oil would be recirculated through the stabilisation train at a slightly elevated temperature. As stabilisation is undertaken effectively at atmospheric pressure the only parameter that would influence the final RVP/TVP is the temperature in this separator (or any gas underflow due to lack of residence time). Gas under flowing would in any event be removed in the dehydration tank vent system.

Water residence times of up to 7 years can be accommodated at initial water production rates. It is highly unlikely that water cannot be de-oiled to less than 15ppm after such long residence times simply by gravity segregation. This could be due to the formation of a very stable emulsion. Such emulsions would be treated with chemicals or the centrifuge system would be expanded prior to water being discharged over board.

7.6.6 Availability modelling and preliminary results

7.6.6.1 Overview

An initial review of the production availability has been performed including all facilities from the wells to the INGL transmission system at Dor. This modelling work will be further enhanced in the next design stage. Failure data used to date is not specific to clean gas service and hence likely over estimates failure frequencies for valves, vessels etc. Comparing the proposed design of the Karish FPSO with other gas processing FPSO's offshore platforms and onshore facilities an availability, including an allowance for planned maintenance, in excess of 98% would be expected.

Currently the RAM model indicates an availability level of 94.1% (for a scenario that does not exactly reflect the actual equipment configuration adopted within this FDP) with planned maintenance included and 95.2% without planned maintenance. These levels equate to an average maximum production rate of 376 mmscf/day gas and 8,371 bpd oil (with planned maintenance), or 381 mmscf/day gas and 8,470 bpd oil (without planned maintenance) for an FPSO with a name plate capacity of 400 mmscf/day.

It is estimated that there will be an average of 9.0 shutdowns per year due to equipment failures. The average duration of shutdown is 53.4 hours.

Flaring is assumed when the flash gas compression system fails. Around 5.5 flaring excursions per year are predicted with a total duration of around 300 hours. The total annual flaring volume due to flash gas compressor failures is estimated to be approx. 21.5 MMSCF.

7.6.6.2 Critical equipment

88% of the predicted production loss is caused by failures of equipment on the FPSO. Onshore facility failures contribute to around 11% of loss and subsea facilities contributes to less than 1%.

Production separation is the largest contributor to the calculated downtime contributing some 25.9% of the total loss, due to failure of these relatively simple, static, items of equipment. This high contribution results from the available data indicating that high pressure separators fail more frequently than low pressure separators. These static items are commonly not spared. The HP and MP separators contribute 8.2% of the predicted loss between them. As discussed above it is probable that failures of static equipment is over estimated as available data does not differentiate between oil and gas, clean or dirty services.

Oil stabilisation and dew point control systems are the second and third largest individual loss contributors due again to the fact that these systems are single trains with minimal sparing. Options to spare dynamic components (control valves) to increase availability will be examined in the next design phase.

Heaters and exchangers also contribute significant downtime because they have higher failure rates than other static components and are commonly not spared, unlike other vulnerable equipment such as pumps and compressors. Again heat exchanger failures – due to corrosion and blockage – are likely over estimated compared with that could be expected with the clean, benign fluids to be produced from Karish and Tanin.

7.6.6.3 Sensitivities

Some initial RAM sensitivity work has been undertaken in the concept design phase. Four separate sensitivity cases have been modelled to assess the effect of different design options. The following table presents an overview of all these cases.

Table 7-30: RAM Sensitivity case results overview

System / Equipment	Base Case Availability
Base Case <i>2 x 100% power generator with 2 x 100% export gas compressor with gas turbine driver</i>	95.2%
Case 1 <i>3 x 50% power generator with 2 x 100% export gas compressor with electric motor driver</i>	95.6%
Case 2 <i>2 x 50% HP Separation and Dew pointing</i>	95.8%
Case 3 <i>2 x 50% liquid separation (MP/ LP separator) and condensate processing</i>	94.3%
Case 4 <i>5-stage liquid separation</i>	95.6%

As can be observed, availability is influenced by both the design adopted and the amount of spare equipment provided. Some of the sensitivities examined have already led to changes to the earlier “base case” assumed in this work. For example, the FDP adopts the use of 3 x 50% power units and electric driven compressors rather than 2 x 100% units with gas turbine driven compressors. This results in a decrease in downtime of 0.4%. Similarly a 5-stage liquid separation train rather than a stabilisation system with a condensate stabilisation column has been adopted. This is predicted to increase uptime by 1.3%. In addition to the above work an initial examination of the failure data employed in the models has been undertaken. Currently OREDA data is used for HP and MP separators. It is however believed that generic vessel data is more applicable. Making this change adds a further 0.2% to the calculated availability.

As stated above RAM modelling will continue into FEED. Whilst the current predicted availability is in the order of 97% (without maintenance) it is expected that further optimisation of the model, and the facility design will eventually lead to an availability above 98% (including planned maintenance turn arounds).

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7.6.7 Tanin flow assurance and hydrate management

7.6.7.1 General

It is proposed that Tanin hydrate management will be based on DEH – electrical heating of the production pipeline. It is understood that this system has been qualified for the water depths between Karish and Tanin but not yet implemented. Schemes for 40 km long pipelines have been executed. Tanin however is not expected to be produced for 10 to 14 years after the Karish Main field is developed. Considering trends over the last 10+ years it can be safely assumed that a DEH system will have been installed at these water depths before a development decision for Tanin is taken (earliest 2027).

As a fall-back, there is space and allowance in the current Karish FPSO design which would enable a MEG based configuration to be retrofitted onto the FPSO.

7.6.7.2 Recommended Line Size

The recommended line size for the Tanin infield pipelines is as follows:

- Dual 12" NB LWSCR from the Tanin manifold to the FPSO. The sizing has been performed such that each flowline can produce 200 mmscf/day from 1 well. The flowline sizing has accounted for a produced water rate of 5 bbl/mmscf and uses a minimum FPSO arrival pressure of 200 barg and a reservoir pressure of 550 bar. The sizing has incorporated a required minimum turndown flowrate for each of the dual flowlines to 100 mmscf/day.

7.6.7.3 Slug Volumes

Slug volume management will be a key area to address when Tanin is developed to ensure that slug volumes are kept to reasonable limits. This will require a specific operating strategy to be prepared that would specify, for example, that only one pipeline can be ramped up at a time and not both simultaneously.

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7.7 Drilling and completion

7.7.1 Karish Well design

7.7.1.1 Summary

Neither of the two exploration wells drilled to date in the Karish and Tanin Leases will be re-used; Karish due to its sub-optimal location and Tanin-1 because of the expected delay in developing the Tanin discovery.

The initial drilling phase is planned to include up to 3 development wells on the Karish Main Field. The option of drilling a well to the nearby Karish North appraisal target immediately following the development wells is currently under consideration. Tanin drilling will follow later in the field life following a similar drilling strategy as Karish. The timing of the Tanin phase is dependent on the level of gas sales, the Karish Main reservoir performance and the possible earlier development of Karish North.

The development wells do not have full reservoir characterisation as they are offset from the discovery wells therefore require directional pilot holes for complete evaluation of the entire Karish objective interval. These pilot holes will be evaluated with MWD/LWD, Electric Line Logging, and conventional cores. These wellbores will then be plugged back, and a side-track performed to optimally set the production casing into the target completion sand.

It is anticipated that all development wells will be completed subsea with single-zone Open Hole Gravel Pack (OHGP) lower completions, consistent with industry standard design for reliable, ultra-high-rate gas production wells.

The wells will be drilled with a Water Based Drilling Mud (WBM) below the surface casing and through to the TD of the well immediately above the reservoir section to be produced. During completion operations, the reservoir section will be drilled using a water-base Reservoir Drill-In Fluid (RDIF). An OHGP will be installed as the sand-face lower completion, and 7-inch tubing will be installed for the upper completion.

A Mobile Offshore Drilling Unit (MODU), as described in Section 7.7.3, will be used to drill and complete the wells. The actual rig and drilling schedule will be determined in accordance with the project schedule to timely deliver First Gas. It is anticipated drilling will commence Q3 2018.

The Karish Main wells will be drilled from a central subsea cluster resulting in the requirement for deviated wells. The final trajectories will be dependent on the individual well PDDPs but will be low to medium angle with a maximum inclination of approximately 42° to reach the drilling targets. No requirement for complex 3D well paths is foreseen at this stage. The well inclination will be kept low (25°) in the 17-1/2" hole section and reach maximum inclination in the 12.1/4" hole section. A side view of the preliminary well paths is given in the below figure.

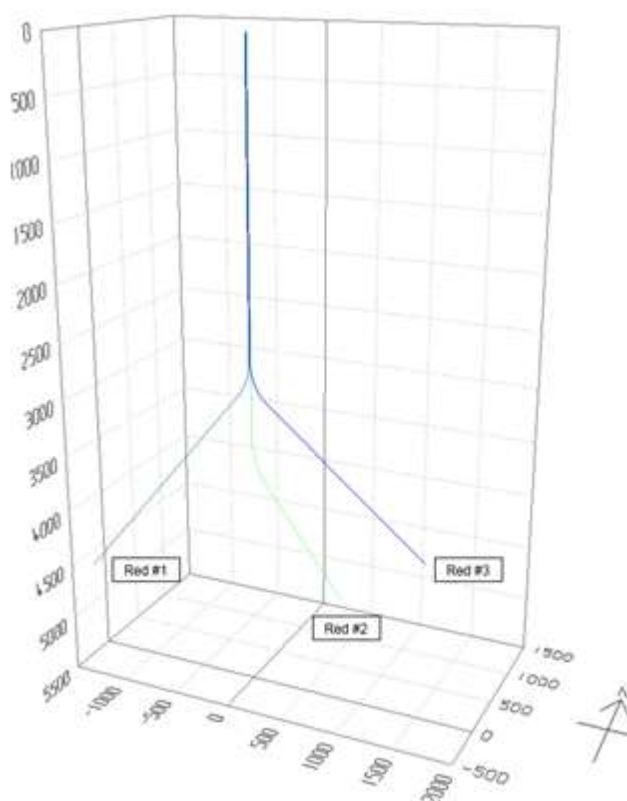


Figure 7-67 Preliminary well trajectories

It is anticipated that KM-1 will be the first well drilled. The well is currently proposed as targeting the structural high in the central fault block in the Karish field. While the well will be completed as a C sand producer it will involve drilling a pilot hole to the D sand to provide information around reservoir quality, continuity and possible contacts within the D sands.

The drilling objectives and key performance indicators are displayed in the table below:

Table 7-31: Karish drilling objectives

Description
NO HARM to people, the environment, or property.
Drill and evaluate for biogenic gas in the Miocene sands
Deliver wells within budget
Deliver Safe and highly reliable well design capable of production requirement of ~200 / mmscf/day per well as the reservoir plateau ends
Achieve Completion Readiness for targeted First gas date

7.7.1.2 Wellhead and Xmas Tree

It is planned to use FMC EHXT (Enhanced Horizontal Xmas Tree) in conjunction with FMC UWD-15 rigid lock-down wellheads. The EHXT is an Enhanced Horizontal Xmas Tree for deep-water applications. EHXT systems are qualified for ultra-deep water (<10,000 feet), extended temperatures (<=300F) and up to 15,000 psi working pressure. They are suited for funnel down guideline-less (GLL) installation on close cluster or satellite wells as per the Karish and Tanin field layout. The tree will have an Insert Retrievable Choke (IRC) and a flow meter with replaceable electronics. The tubing hanger (TH) is designed to land and lock in its composite valve block of the Tree with the BOP (Blow out Preventer) attached to the top of the EHXT.

The UWD-15 wellhead can accommodate 3 casing strings with 1 million lbs capacity in each string. The rigid lock down system locks the High Pressure Wellhead Housing (HPWHH) in place inside the Low Pressure Wellhead Housing (LPWHH) and transfers the major loads to the conductor.

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7.7.1.3 Casing Scheme

All depths are MD unless otherwise stated. Subsea depths are relative to MSL unless otherwise stated.

7.7.1.3.1 36" Conductor

The 36" conductor will be jetted into position at 1,834m TVD. The depth is based on successful operations on offset wells, to be confirmed with conductor fatigue analysis during the detailed design phase. The conductor string will isolate unconsolidated shallow formations and provide structural support for the wellhead and BOP.

7.7.1.3.2 20" Surface Casing

The 26" section is to be drilled to ~2,605m MD prior to setting 20" surface casing at 2,602m MD. The string shall consist of a 18-3/4" high pressure wellhead housing, 21" extension joint before crossing over below to 20" casing. Once ran to depth the string will be cemented to seabed with 12.5 ppg Class G lead and a 150 m 16 ppg Class G tail to:

- Isolate potential weak zone at the top of the evaporite.
- Allow BOP and riser to be installed.
- Provide sufficient shoe strength to reach required 13-5/8" casing setting depth.

7.7.1.3.3 13-5/8" Intermediate Casing

The 17-1/2" section is to be drilled to 3,143 m TVDSS prior to setting 13-5/8" surface casing at 3,140 m TVDSS. Once at depth the string will be cemented to 2,250 m with 12.5 ppg Class G lead and 150 m 16 ppg Class G tail to:

- Provide sufficient shoe strength to allow drilling to 12-1/4" section TD safely.
- Set casing above the pressure ramp expected below the base of the salt.

7.7.1.3.4 10-3/4" x 9-5/8" Production Casing

The 12-1/4" section is to be drilled to 4,605 m MD prior to setting 10-3/4" x 9-5/8" production casing at 4,600 m MD with crossover at 2,580 m. The section of 9-5/8" casing below the production packer will be 13% Chrome due to the expected CO₂ levels. The casing will be cemented to 3,040 m with 12.5 ppg Class G lead and 150 m 16 ppg Class G tail:

- Set casing at near or top reservoir - to be defined during detailed well design
- Provide sufficient shoe strength to allow drilling into reservoir safely
- Provide sufficient shoe strength for minimum 50 bbl kick tolerance in 8-1/2" reservoir section
- Provide a ranging target for relief well drilling if required

Note: The requirement for 9-7/8" casing for additional strength over 9-5/8" will be assessed on an individual well basis during the detailed planning phase.

Figure 7-68 Casing Schematic

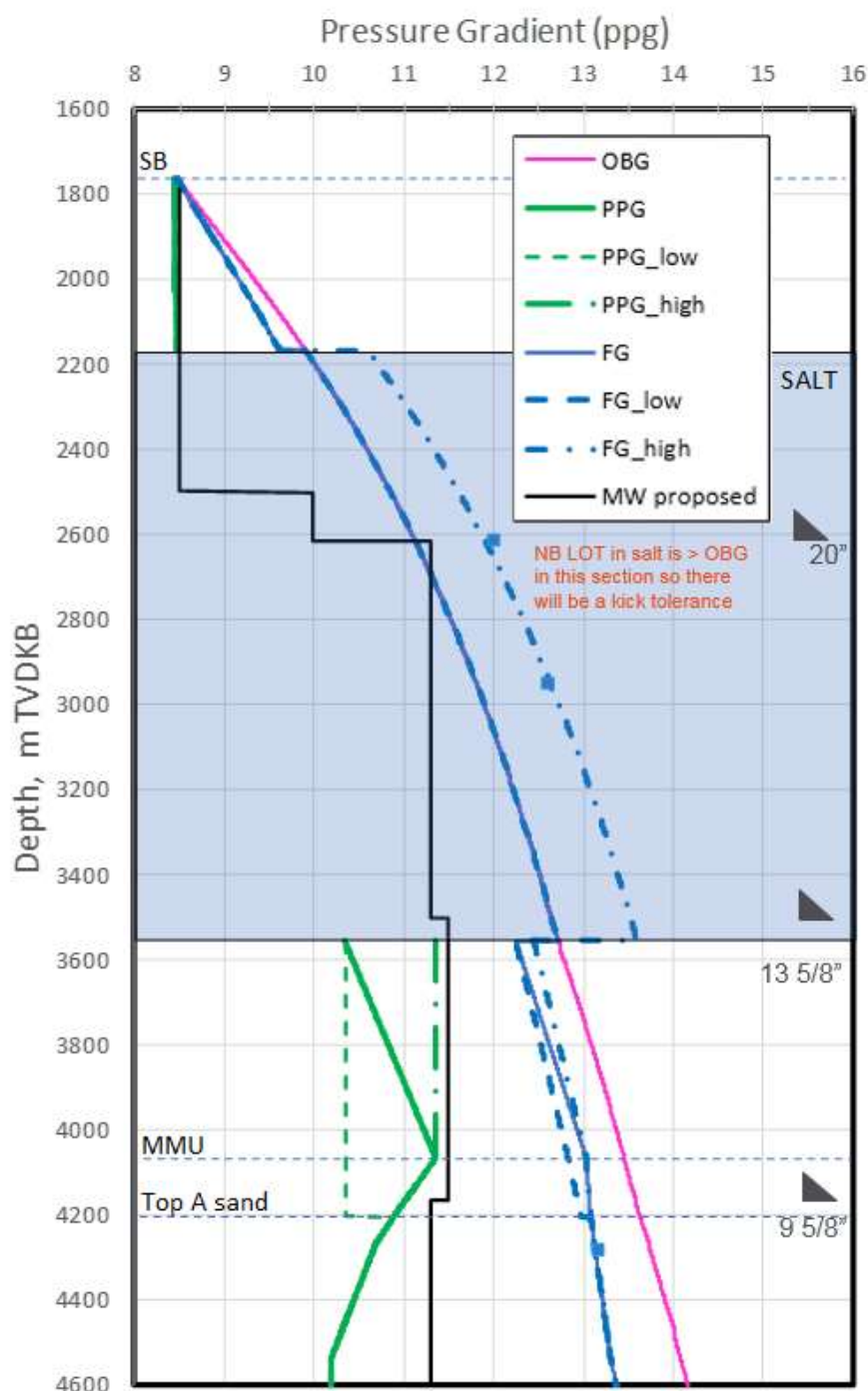


Figure 7-69 Pore Pressure/Fracture Gradient chart

7.7.1.4 Pore Pressure & Fracture Gradient

The above graph shows the predicted range of pore pressures and fracture gradients along with preliminary mud weight selection and overburden. Of note is the large salt section where no pore pressure prediction is given due to the lack of permeability in the formation. The selected mud weights through this section are based on offset well data. On the offset wells leak-off test values achieved have been found to be higher than the overburden gradient, again due to the nature of the salt formation. Below the salt zone, a pore pressure ramp is expected making the placement of the intermediate casing shoe critical. Sufficient window exists between the high-side pore pressure estimate and fracture gradient through the reservoir to accommodate the expected drilling ECD and provide the required kick tolerance.

7.7.1.5 Fluid System

A review of the offset Karish and Tanin wells indicates there is no requirement to use Oil Based Muds (OBM) to successfully drill the wells. Additionally, the use of Water Based Mud (WBM) provides a number of operational benefits;

- Increased compatibility between Reservoir Drill-In Fluid (RDIF) and Gravel Pack fluids,
- Reduced potential environmental impacts from a non-hydrocarbon based drilling fluid,
- No requirement to capture drill cuttings and ship to shore for treatment or disposal,
- Increased logistical flexibility compared to OBM.

The RDIF formulation and design will be tailored to the reservoir characteristics through fluids design which will then be verified with lab work.

7.7.1.6 Cementing Design

The Karish development shall use the same standard cement slurry designs as were used on the Karish -1 exploration well. This was successfully demonstrated to be suitable for the expected well conditions.

Table 7-32: Cement Design

Casing String	Slurry (Lead/ Tail)	Top of Cement (TOC)	Method of verification
Conductor	N/A	N/A	Conductor will be jetted
20"	Class G (12.5 ppg / 16.0 ppg)	Seabed	Pump pressures / ROV Observations
13.5/8"	Class G (12.5 ppg / 16.0 ppg)	350 m above 20" shoe	Pump pressures
10.3/4" x 9.5/8"	Class G (12.5 ppg / 16.0 ppg)	100 m above 13.5/8" shoe	Pump pressures

7.7.1.7 Data Acquisition

The placement of the OHGP Completion at the base of the lowest B unit-shale is a critical part of the drilling programme on all of the Karish Main development wells and necessitates the predrilling of a pilot hole over the reservoir section. Core and log data will be acquired in this pilot section. It will then be abandoned and the well side-tracked precisely to the top of the C reservoir for installation of the OHGP.

7.7.1.7.1 Core Acquisition

A core will be acquired over the B sands in the first well. It is possible that a second core will also be acquired over the C sand, although this has yet to be confirmed. Provisional planning anticipates up to 18 m of core being acquired. SCAL and routine core analysis will be undertaken to confirm logging exponents to be applied in the B sand (and potentially also the C sand) and for calibration of the log data. Studies will be undertaken to establish whether doping of the mud system would allow for a direct determination of the Sw in the preserved core to corroborate measurements estimated by log.

In the event that coring is not undertaken over either of these intervals, then side wall cores would be programmed following the logging programme.

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7.7.1.7.2 Logging Programme

Logging of the reservoir section in the development wells will be carried out within the pilot boreholes. This pilot well bore will be drilled to a depth sufficiently below the currently estimated GWC (4512m) to provide for a logging rat hole.

The proposed logging suite run in WBM will comprise:

- Run 1: Resistivity - Sonic dipole - Density - Porosity – Spectral Gamma Ray
- Run 2: Formation Electrical Micro-Imaging
- Run 3: Magnetic Resonance + Formation Pressures
- Run 4: Formation Fluid Sampling
- Run 5: Vertical Seismic Profiling

Alternatively and depending on the final hole size, it would be possible to complete Runs 1 to 3 with LWD prior to running wireline to collect samples, reservoir pressures and the vertical seismic profile.

7.7.1.7.3 Well Test Programme

Each of the wells will be cleaned-up and suspended with a benign completion fluid placed across the reservoir and OHGP. It is anticipated that the well clean-up process will be batched to allow for the testing of the three development wells to be carried out, one after the other, and the wells suspended. Testing of the wells will comprise:

Unloading and Clean-Up Period – (12-24 hours)

This period will see the well flowed and the fluids captured and the gas flared with the objective of removing as much of the drilling fluids and detritus and OHGP placement fluids from the well as is practical.

Test Period - (18 hrs)

This period will see the well flowed through a surface test spread and the gas flared with the objective of ensuring a minimal completion skin and an assessment of the wells Kh, PI and Initial gas rate potential, ahead of the suspension of the well. Details of the exact programme to be implemented will be worked on with the testing and drilling contractors.

7.7.1.8 Lower Completion Design: Initial C/D Development

7.7.1.8.1 Design Summary

Due to the nature of the reservoirs and the expected production rates all of the lower completions will require sand control. The wells will be single zone completions which are designed as Open Hole Gravel Packs (OHGP) to provide maximum gas deliverability and minimize drawdown pressure and sand production. The Karish well completions are currently planned to be single-zone, conventional water packed, OHGP completions with the C Sand as the primary target. The B Sand will be targeted later and the wells re-completed with a single zone Cased Hole Gravel Pack (CHGP). The D Sand package(s) will be logged and evaluated for further assessment. It is envisaged that the D sand volumes will be produced whilst producing the C volumes due to the presence of many faults that are not expected to seal. The OHGP design is a continuation of the highly engineered and successful Tamar design, which was implemented offshore Israel in 2012.

7.7.1.8.2 Lower Completion – Concept Selection

The Karish and Tanin sand face strategy is based on regional core and side-wall core from the discovery wells, which indicates that the reservoir is weakly consolidated and prone to sand production, thus will require downhole sand control.

Various methods are employed by the industry when sand control is required and have been considered for the lower completion. The initial selection is summarised in the table below:

Table 7-33: Sand Control Methods

Sand Control Method	Comment on Suitability
Stand Alone Screens	- Not suitable in a poorly sorted, high fines content environment - Plugging and severe erosion potential
Expandable Sand Screens (ESS) – Cased Hole and Open Hole Variants (OHESS & CHESS)	- No proven track record in high rate gas environment - Any reservoir compaction could cause screen collapse of OH ESS - High risk option in subsea high rate gas environment with +20 year life expectancy
Frac and Pack	- Production capability sufficient - Difficult to control frac geometry in deviated open hole 5 ½" screens largest size in 9-5/8" cased option - Operational logistics challenges (frac boat)
Alternative Path / Shunt Tube Gravel Pack	- More applicable in shale environment and for unstable wellbore conditions or long heterogeneous horizontals - Drop in base pipe size to accommodate shunts (5 ½" largest)
Open Hole Gravel Pack	- Proven track record in high rate gas wells - Broad retention capability - Risk of incomplete pack mitigated through low angle wells - Plugging mitigated through fines tolerant design
Cased Hole Gravel Pack	- Broad retention capability - Plugging mitigated through fines tolerant design - Provides annular isolation for multi-zone completions

The initial selection concluded that a gravel pack solution – either open-hole, OHGP or cased-hole, CHGP – was the preferred method of sand control and warranted further consideration. The OHGP design was evaluated against a cased-hole version. The potential benefits of the OHGP being lower skin, cost savings of avoiding cemented and perforated liner costs and increased gas rate production potential. The main issues are to ensure a good pack in an open hole and ensure no major issues with reactive shales, unstable wellbore conditions or long heterogeneous deviated intervals. Alternative path / shunt tubes options can ensure a good pack and by-pass annular obstructions if such conditions are present or to by-pass open-hole packers in multizone wells. However, the drop in base pipe diameter needed to accommodate shunts needs to be evaluated for the productivity trade-off. Zonal isolation options for water shut-off in open hole also require to be evaluated to ensure an adequate solution is selected.

Initial design work was initiated on the basis that the D Sand would not be in communication with the C Sand. Fault seal studies were performed in parallel. It was however contemplated that a multi-zone completion over the C and D zones could suffer from early water production into deeper - D Sand - interval, via the completion / sand face annulus. A cased and cemented hole is normally better to facilitate zonal (annular) isolation than open hole. The CHGP was considered an effective multi-zone completion method to be able to target and

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produce the D sand until water production levels mean that isolation is required for water shut-off before subsequent production from the C sand above.

However, to achieve the required production rates a 9-5/8" casing/liner based CHGP through the reservoir is required. This would mean drilling the reservoir interval in 12-1/4" hole size. As a result, the well architecture would have to be significantly changed to accommodate a 9-5/8" casing at well TD. These changes would include:

- Non-standard wellhead & casing strings to be run,
- Increased cost over standard system,
- Required casing specification not identified and may require custom build,
- The requirement to under-ream hole sections and allow larger casing strings to be run,
- Increased time & cost to drill,
- Increased risk of BHA failure resulting in BHA trip or fish in hole,
- The larger casing strings would result in tighter tolerances,
- Increased risk of hold up when RIH,
- Increased risk of surge/ swab,
- Increased difficulty to achieve successful cement jobs,
- Flush casing connections may be required – potentially insufficient strength to meet well loads,
- Drilling hydraulics and hole cleaning may prove difficult leading to increased time to drill sections,
- Additional circulation times to clean the wellbore.

It should be noted that there is no local offset of this type of casing architecture, primarily as the offset wells have targeted a single sand unit for production.

Following completion of fault seal analysis it was conclude that there was a very high chance of communication between the C and D reservoirs. Mapped faults juxtapose in many areas and these faults are not predicted to be sealed. It was decided therefore to drop the CHGP multi-zone completion and use a single zone OHGP solution to target and produce the C zone.

Additionally, with a single zone and low angle trajectory a conventional water pack OHGP can be performed negating the requirement for alternative path / shunt tube gravel pack systems to by-pass problematic shale sections, unstable hole conditions, or packers in multi-zone completions.

In conclusion, Open Hole Gravel Pack was the preferred solution for the application as:

- They have a proven track record in high rate gas wells,
- They provide broad grain size retention capability,
- The risk of an incomplete pack is mitigated through low angle wells,
- The risk of plugging is mitigated through a fines tolerant design,
- They allow use of proven wellhead and casing architecture,
- For ultra-high gas rates (>150 mmscf/day) the OHGP has been the technical preference in the industry worldwide and has an excellent track record of efficient completions (low drawdown, low skin), as well as, high reserve recovery (+300 Bcf/well).

7.7.1.8.3 Lower Completion Design

The lower completion strategy for Karish is to utilise a single-sand, conventional water packed, OHGP as the primary completion method with the primary target being the C sand. The lower completion will have a gravel pack string including a gravel pack packer, fluid loss control device, sand screens and gravel pack wash down shoe. Initial Particle Size Distribution (PSD) analysis from sidewall core from the Karish-1 and Tanin-1 wells suggest a 150-175 micron premium mesh screen with 40/60 gravel should be used. The base case design assumes 6-5/8" screens in 12-1/4" hole (under-reamed from 8-1/2").

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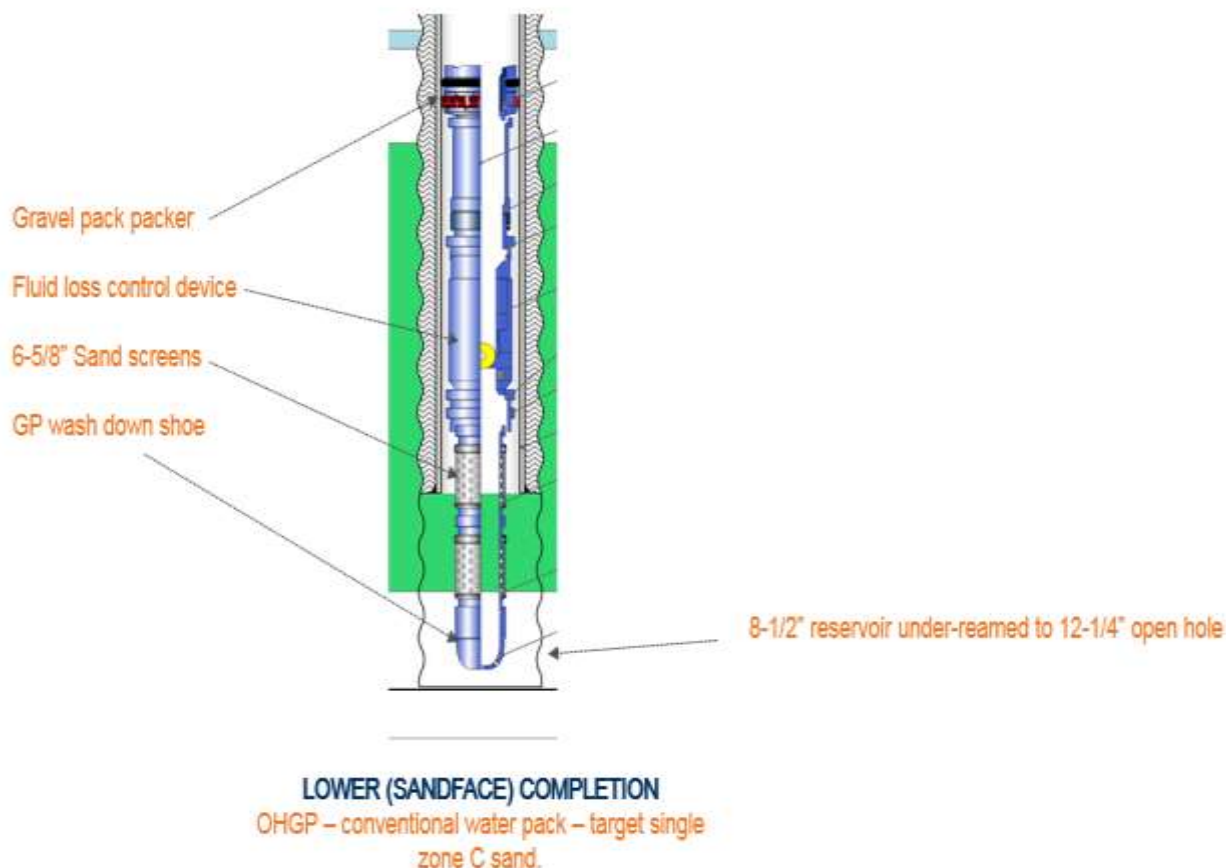


Figure 7-70 Lower sand face completion

7.7.1.9 Upper Completion Design: Initial C/D Development

7.7.1.9.1 Upper Completion Design Summary

The wells will be completed with 7" tubing to enable high-rate gas production. The intended production capability for the production wells is 200 - 300 mmscf/day per well; this will allow production targets to still be met if one of the three wells is shut-in or fails to produce for any reason.

Each well will be equipped with a surface controlled subsurface safety valve (SCSSV) below the mudline to prevent an uncontrolled release of hydrocarbons. The 9-5/8 x 10-3/4" crossover is set approximately 800 m below the mud line, deep enough to allow for installation of a 5-1/2" Surface-Controlled Subsurface Safety Valve (SCSSV) at a depth and temperature that provides adequate hydrate inhibition.

In addition, each well will be equipped with a dual Downhole Pressure Temperature (DHPT) gauge for real-time downhole surveillance and with Chemical Injection Mandrels (CIMs) for mitigation against the potential risk of scale or hydrates.

7.7.1.9.2 Tubing Sizing

Four tubing sizes were considered and evaluated for the Karish field development viz: 5", 5-1/2", 7" and 7-5/8". However, the 5" and 7-5/8" tubing sizes were discounted early on. The 5" tubing size was discounted primarily because flow velocities within the tubing are likely to exceed erosional velocity limits under the projected tubing head pressure (THP) and flow rate operating envelope. The 7-5/8" was discounted as there was a significantly higher liquid loading risk relative to the 7" tubing, with no significant benefit in terms of reduced back pressure at the expected rates.

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More detailed modelling was undertaken to compare the performance of the 5-1/2" tubing with that of the 7" tubing size. To facilitate the tubing selection, a produced gas rate / water gas ratio (WGR) sensitivity analysis was conducted on the 5-1/2" and 7" tubing sizes over the expected range of tubing head pressure (THP) and reservoir pressure values to investigate the impact of potential water influx on well performance across field life. A full field network case was also run to attempt to quantify the impact of potential liquid loading. The conclusion from the simulation work was that the 7" tubing was the preferred tubing size for the Karish field development wells.

The 5-1/2" tubing presents no significant advantage in terms of water production over the planned field life, based on the planned development strategy especially since water breakthrough into any of the Karish wells is not predicted until sometime middle to late life. This, coupled with the fact that a top-hole workover could be undertaken to replace the 7" production string with a smaller (effective) diameter string should liquid loading / water production become an issue negates the advantage of the 5-1/2" tubing. Overall, the 7" tubing is selected to allow the wells perform adequately within the expected initial flowrate range, and to continue to do so until water production levels are such that a smaller diameter string is required.

7.7.1.9.3 Tubing Design

The conceptual tubing design is based on the preferred 7" tubing. However, this will be crossed over to a 5-1/2" tubing to accommodate a 5-1/2" downhole pressure-temperature gauge mandrel within the 9-5/8" production casing.

0.076 mole % (6 psia initial partial pressure) CO₂ concentration and a negligible H₂S concentration implies that the minimum acceptable metallurgy for the Karish tubing is 13Cr. This is consistent with tubing metallurgy deployed by Noble in their Tamar wells. Should H₂S concentration be as high as 10 ppm then the minimum acceptable metallurgy will be SM13CRS or equivalent.

Tubing stress analysis (TSA) suggests that a 7" 35.0# SM13CRM-110 VAM Top HC x 5.5" 23.0# SM13CRM-110 VAM Top HC or equivalent tubing string is suitable / acceptable for the expected tubing loads provided that the loads applied to the production packer are within its operating envelope. VAM Top HC or equivalent premium connection is preferred because of their excellent gas sealing properties and 100% pipe body material strength performance.

7.7.1.9.4 Upper Completion – Main Components

The upper completion design requires 7" tubing to deliver the desired gas rate. The top segment of the upper completion will be equipped with a 5-1/2" SCSSV and a chemical injection mandrel (CIM). The lower segment of the upper completion will be equipped with a downhole permanent pressure and temperature (DHPT) gauge for real-time downhole surveillance and CIM immediately above a permanent production packer. The top CIM is for injecting methanol above the SCSSV to mitigate hydrate formation. The lower CIM is a contingency should chemical injection be required for scale inhibition or other flow assurance issues.

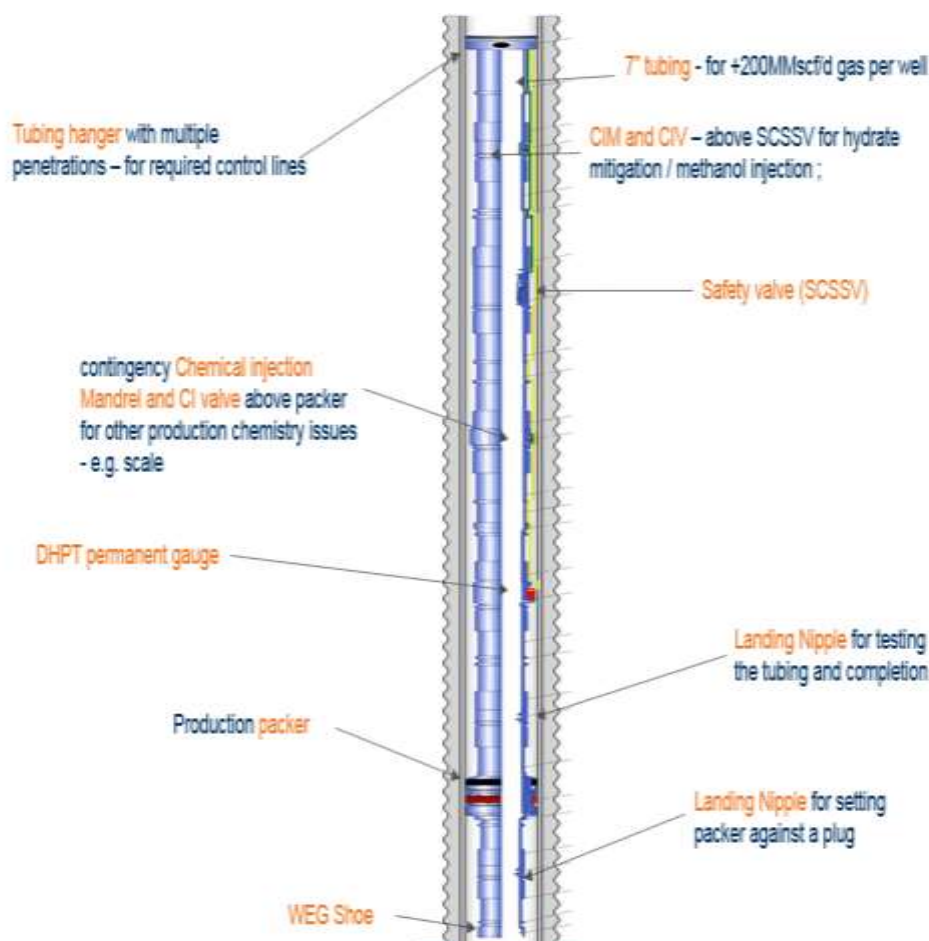


Figure 7-71 Upper completion design

7.7.1.10 Well Clean-up Flow

Well Clean-up will be via an initial flow through the rig rather than waiting until the FPSO and subsea facilities are installed and commissioned. This was preferred to a clean-up to the FPSO because of the following risks:

- Considerable infrastructure implications and cost to the FPSO to handle wellbore fluids, filter cake, sand and other solids,
- If bringing on wells with FPSO was not successful, the cost of a rig or intervention vessel could be significant - potentially delaying first gas and risking production levels at the start of field life,
- There is an increased risk of damage to the completion via production operators who may not have the specialist knowledge to bring on the well in a controlled manner.

Performing an initial clean up flow through the rig has significant technical advantages:

- It is prudent to gain an understanding of well performance (production rate, skins, etc.) without waiting to hook up and commission the subsea system and FPSO,
- If remedial treatments or intervention are required, the rig and equipment are in place to act,
- If there is sand production from the start, the well test spread and landing string are temporary equipment which can be replaced whereas the FPSO and subsea production infrastructure are permanent and very costly to replace,
- In summary, the main benefit is having everything in place to flow the well back and perform any corrective actions without having to re-mobilise a rig.

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7.7.1.11 Workovers and re-completions: Later B Development

Subsurface work has indicated that there may be more volume of gas in the B Sands than originally thought. Some part of this volume (as discussed in Section 6) will be produced via wells completed on the C sand. However most gas in place will be left behind. Options to install a multi-zone completion over the B and C zones have been studied but disregarded for similar reasons as the rejection of a C/D multi-zone approach. Furthermore the exact potential of the B sands will not be understood until high resolution logs and cores are gathered in the initial development campaign.

It is therefore planned currently that the potential of the B sands will be developed from the original 3 wells once the C/D sands have watered out. Water saturations in the B sands may also be higher than in the C sands and formation water may break through differently due to the increased heterogeneities resulting from the thin laminated sand sections. A workover and re-completion will be performed in later field life to target the B sand after the C sand has been produced. An allowance for this work is included in the projected forward budget.

The original upper 7" completion will be recovered, then a bridge plug set above the C sand. The 9-5/8" cemented casing will be perforated over the B sand target before a CHGP with 5 1/2" sand screens are run internally. The upper completion will then be re-completed with a smaller tubing size, 5-1/2" (or other appropriately sized tubing), to allow production from the B zone while handling any water production.

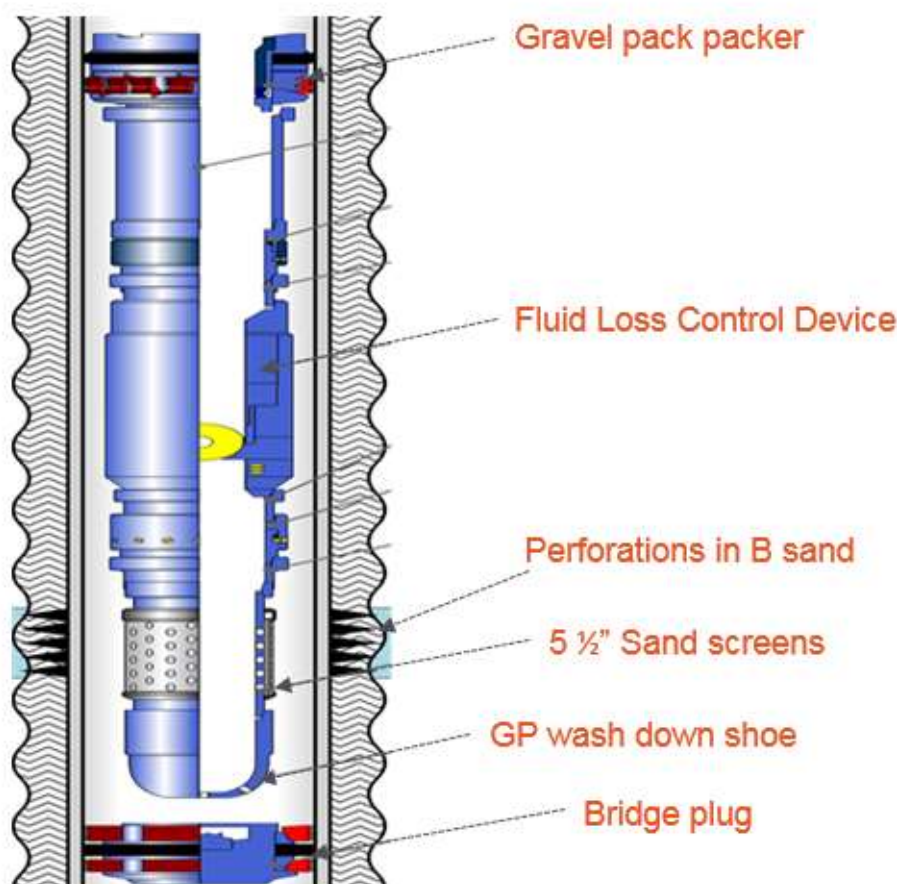


Figure 7-72 Lower completion Recompletion on B sands

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7.7.2 Tanin Well Development

The Tanin field will be developed after completion of the Karish Main field and possibly also after development of Karish North. The base plan is for the Tanin wells to be very similar to those drilled on Karish i.e. a cluster development of deviated/ directional wells on Block A, with a remote well (or wells) on Block C and much later on Block B. The Block C well(s) would be drilled with a horizontal OHGP in the crest(s) of this relatively flat structure. During operations on the Karish field “lessons-learned” will be captured and applied to the later future Tanin field development wells.

7.7.3 Drilling Rig Requirements

The drilling and completion rig(s) will have the following minimum general specifications:

Drillship or semisubmersible MODU.

- Minimum drilling depth capability in excess of 8,000 m.
- Minimum working water depth in excess of 1,800 m.
- Well control equipment rated at 10,000 psi capacity.
- 18-3/4", 10,000 psi BOP system with five ram-type preventers.
- Hook load of 1,500 kips and 60.5"-inch rotary table.
- Top drive to deliver 50,000 ft.-lbs of torque at continuous drilling RPM of 130.
- Three mud pumps rated at 7,500 psi.
- Bulk storage for 10,000 sacks of cement and 6,000 sacks of barite.
- Fluid storage of 17,000 bbls for active and reserve pits, and additional storage for 6,000 bbls of brine.
- Rig will have zero discharge capability with respect to muds and drill cuttings.
- Pipe and tubular handling for all drill pipe, casing, and tubing required for the project.
- Completion and well testing capabilities.
- Personnel capacity of approx. 180.

7.7.4 Drilling Services Provision

The final service providers for the development are still to be determined. The number of service providers will be minimised to reduce interface complexity and help ensure a high standard of service. A key factor in selecting the vendors will be their experience in relevant offset developments. The competency and quality assurance procedures of the main vendors will be assessed prior to operations commencing. Contracting Strategy for the drilling phase is discussed further in section 9.1.1.1.

7.7.5 Logistics

Prior to operations starting an assessment of the required logistics infrastructure will be made. This will be developed into a detailed logistics support plan including the following aspects:

- Marine Support
- Aviation and Crew Change
- Materials Management
- Logistics Operations Management
- Customs requirements

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8 Project Schedule and Costs

8.1 Project Schedule and key milestone

8.1.1 Project schedule & Critical Path

The main schedule milestones for the Karish FPSO and Subsea Development project are as follows:

- Subsea Pre-FID Engineering Design contract award: end May 2017
- Selection of hull fabrication yard: July 2017
- Selection of topsides and integration yard: July 2017
- Geotechnical, geophysical and Environmental Base Line Survey: July 2017
- Approval of FDP by Israeli government: August 2017
- Selection of rig and drilling services contractors: August 2017
- Award of EPCmIC contract: October 2017
- Completion of full project EIA (ESIA): October 2017
- ITT's issued for identified Long Lead items
- Project sanction: end 2017
- Award main project contracts: January 2018
- Commence hull fabrication: Q1 2018
- Commence drilling operations: Q3 2018
- Commence FPSO hull topsides integration and commissioning: Q2 2019
- Complete drilling operations: Q2 2019
- Commence pipeline installation: Q2 2019
- Undertake SURF pipeline installation: Q3 2019
- Mobilise FPSO from Asia to Europe: Q4 2019
- Hook-up FPSO to SURF and pipeline: Q1 2020
- Final commissioning and start-up: Q1 2020
- First gas sales: April 2020
- First oil sales: June 2020

Detailed schedules for the FPSO fabrication scope and the offshore construction and installation scope are included as attachments to the FDP. A full integrated schedule including drilling etc. will be prepared and risked in the next phase. The project will involve the timely evaluation and award of major contracts and purchase orders.

Critical Path activities have been identified as:

- FPSO Hull
- FPSO Topside Modules
- Subsea Manifold
- Subsea Xmas Trees

To be able to meet the First Gas dates the procurement of long lead items (detailed in subsequent section) will need to be procured in a timely manner.

8.1.2 Long lead items

8.1.2.1 SURF and FPSO Long Lead items

A Long Lead Item (LLI) register for major equipment has been developed in order to de-risk the schedule as project progresses. LLI's are defined as equipment or materials with a lead time of 12 months or more. This allows the project management team to identify lead times for major equipment and build it into the engineering, procurement and construction (EPC) schedule and activity sequencing, thus mitigating schedule risk as much

as possible. Major equipment lead times are shown below and will be categorized according to their lead time and criticality.

Table 8-1: Facilities and SURF long lead items

Equipment	Delivery time ex works (months)	LLI	Source of estimate*
Process Equipment and Systems			
Separation Vessels (incl. coalescer)	10-13	Y	Experience based
LP Gas Compressor (Electric motor)	12	Y	Supplier input
Export Gas Compressor (Electric Motor)	12-14	Y	Supplier input
Export Gas Compressor (Gas Turbine)	12-14	Y	Supplier input
Choke valves	12	Y	Experience based
Electrical Systems			
Emergency Generator (diesel)	12-14	Y	Experience based
VSDs	12	Y	Procurement Database
Gas Turbine Generators	12-14	Y	Supplier input
Marine (utility) Systems and Hull			
Hydraulic Power Unit	12	Y	Procurement Database
Main cranes	14	Y	Supplier input
Cargo, seawater, ballast and firewater pumps	12	Y	Supplier input
Free fall lifeboats	10-12	Y	Supplier input
Offloading system	12	Y	Supplier input
Riser pull-in system	12-14	Y	Supplier input
Mooring pull-in winch and chain stoppers	12-14	Y	Supplier input
Mooring lines	12-14	Y	Supplier input

8.1.2.2 Drilling Long Lead items

The table below summarizes the long lead well construction equipment. The longest lead item is the EHXT (Enhanced Horizontal Christmas Tree) from TechnipFMC with a 17-month lead-time. This gives an estimated ready date for all equipment of 1st January 2019. It may be possible to commence operations sooner than this date, particularly if the wells are to be batch drilled down to the setting of the production casing.

Table 8-2: Drilling long-lead items analysis

Item	Description	Source of Information	Lead Time
Wellhead	TechnipFMC	TechnipFMC	8 months
Xmas Tree	EHXT	TechnipFMC	17 months
Conductor			6 months
20" Casing	147# / K-55	Tenaris	9.5 months
13-5/8" Casing	88.2 # / Q-125	Tenaris	7 months
10-3/4" casing	65.7 # / Q-125	Tenaris	7 months
9-5/8" Casing	53.5 # / Q-125	Tenaris	7 months
9-5/8" Casing	53.5 # / TN 125Cr13S	Tenaris	12 months
Float equipment		Weatherford	10 – 15 weeks
OHGP (Single Zone)	OHGP Equipment	Schlumberger	6 months ex. works
7" & 5-1/2" production Tubing		Vallourec	9 months ex. works
Permanent Packer	Production Packer	Schlumberger / Baker Hughes	6 months ex. works
Upper Completion Equipment		Schlumberger / Baker Hughes	6 months ex. works

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SSTT		Expro	13 months

8.1.3 Schedule Risk Assessment

A schedule risk assessment shall form part of the project risk register, which shall be developed during the next design phase of the project.

8.2 Cost Estimate at the end of Concept Engineering

8.2.1 Well construction

8.2.1.1 Introduction

A budgetary estimate has been prepared based on the following assumptions:

- A dual-derrick, DP, 6th generation drillship will be employed,
- Wells will be drilled from a central location north of the production management. Angle will be built from within the salt section,
- A 12.1/4" pilot-hole interval drilled from the 13.5/8" shoe to the base D Sands to optimise the 9.5/8" shoe placement,
- The first well will be cored over the B sands,
- All wells will be fully logged in the pilot hole section,
- Each well will be drilled and completed with a single-zone Open Hole Gravel Pack (OHGP) over the top 30m of the C sand interval,
- The wells will be flowed back and cleaned up but no extended well test will be undertaken,
- An Horizontal Xmas Tree will be utilized,
- Individual cost categories have an accuracy of +/- 25%.

It is assumed that the three wells will be batch drilled. The benefits of batch drilling will be fully quantified in the detailed design phase when the Integrated Services Contractor has been selected. Currently the only advantage included is the removal of BOP handling operations in the 2nd and 3rd wells.

P90 – P50 – P10 well timings have been calculated and are outlined in section 9.1.7 below.

8.2.1.2 Rig day rate

Energean Israel has investigated the rig market in parallel with preparing this FDP. A formal Request for Information (RFI) related to drilling rig availability and costs has recently been launched. Returns are however expected after FDP submission. Based upon available market intelligence, as well as discussions with selected rig owners, a range of prices between \$110,000/day to \$235,000/day would appear appropriate. These rates are for 6th generation Drill ships equipped with DP and dual derricks. It is possible that lower specification rigs may be available at lower prices. These rates included an allowance for mobilisation and were based on a 3-well campaign.

A base rig rate of US\$200,000/day has been assumed to calculate the end-Concept drilling cost estimate.

8.2.1.3 Spread rate

Energean Israel has developed an estimate for the projected services day rate based on data obtained via its Concept Design contractor (LR). This data reflects the results of competitive tenders undertaken for two deep water wells drilled in 2016 in Europe and Asia. A day rate has been developed assuming all services will be required for the calculated well duration. Batch drilling should help lower this cost by reducing the duration individual services are required.

A base services cost of US\$201,000/day has been assumed to calculate the end-Concept drilling cost estimate. The build-up of this day rate is outlined in the table below. This cost is estimated to be accurate to +/- 25%.

Table 8-3: Build-up of assumed Drilling Services cost

Service Type	Cost (US\$/day)
Directional Drilling/MWD (Engineer and Equipment)	26,200
Wireline (Engineer and equipment)	5,000
Mud logging (Engineer and equipment)	2,550
Mud Engineering (Engineer and equipment)	2,000
Cement Engineering (Engineer and equipment)	3,370
ROV operations (Engineer and equipment)	4,931
Casing running services (Engineer and equipment)	4,875
Fishing tools	550
Landing string	1,500
H2S Contingency equipment	390
Rig Communications	1,375
Rope, soap and dope	1,250
Misc. Drilling tools	3,125
Reporting Services	280
Helicopters and aviation support	45,625
DSV and NDSV	2,500
Well examination	440
Cement Head and Operator	1,440
Real time data Services	225
Wellsite geologist (x2)	2,500
Production Supply Vessels - PSV (x2)	31,250
PSV fuel	9,100
Stand-by vessel	12,500
Waste services and disposal	1,000
Shaker screens	500

Drill bits and hole openers	8,500
Rig Fuel	22,500
Additional crew (dual activity)	2,000
Additional catering	3,500
Total	200,976

8.2.1.4 Drilling Tangibles

Based upon the conceptual well design discussed in section 7.7 above, budget level cost estimates have been sourced from the market. The following table provides an overview of the drilling related tangible costs. Where costs are defined per unit length the longest well has been used to calculate the per-well cost.

A base drilling tangible cost/well of US\$ 6.62 mln has been employed to calculate the end-Concept drilling CAPEX cost estimate. This estimate is considered to be accurate to +/- 25%.

Table 8-4: Drilling tangibles cost estimate

Item	Source	Cost (US\$)
Wellhead	TechnipFMC quotation 7/4/17	362,500
Conductor	LR data based on planned 2017 well	320,000
20" Casing	Tenaris quotation 31/3/17	722.56/m
13-5/8" Casing	Tenaris quotation 31/3/17	342.76/m
9-5/8" Casing	Tenaris quotation 31/3/17	204.80/m
9-5/8" 13 Cr Casing	Tenaris quotation 31/3/17	956.00/m
Float equipment, etc. (full set)	LR data based on planned 2017 well	366,000
Total		6,617,464.00

8.2.1.5 Completion tangible costs

Based upon the conceptual completion design discussed above, budget level cost estimates have been sourced from the market. The following table provides an overview of the completion related tangible costs.

A base completion tangible cost/well of US\$ 9.35 mln has been employed to calculate the end-Concept drilling CAPEX cost estimate. This estimate is considered to be accurate to +/- 25%.

Table 8-5: Completion tangibles cost estimate

Item	Source	Cost (US\$)
Well test equipment	LR data based on planned 2017 well	1,015,000

SSTT	Expro quotation 10/4/17	750,000
OHGP	LR data based on planned 2017 well	925,000
Upper completion	LR data based on planned 2017 well	625,000
Xmas Tree	TechnipFMC quotation 7/4/17	4,738,682
FMC Installation costs	TechnipFMC quotation 7/4/17	1,300,000
Total		9,353,682

8.2.1.6 Drilling Class II Cost Estimate

The following drilling CAPEX costs have been calculated based upon the above data.

Table 8-6: Total calculated drilling costs – 3 Karish Main development wells

Certainty level	Total days	Total Services Spread rate (US\$ mln)	Total Rig rate (US\$ mln)	Drilling tangibles (US\$ mln)	Completion tangibles (US\$ mln)	Total Drillex (US\$ mln)
P90	379	95.22	94.75	24.82	35.07	248.86
P50	277	55.68	55.40	19.86	28.06	159.00
P10	241	36.33	36.15	14.89	21.04	108.41

Based upon the above analysis the cost of an individual well is calculated as ranging from US\$ 36.1 mln (P10) to \$US 82.9 mln. The P50 cost is \$US 53.0 mln.

8.2.2 Karish SURF

The cost estimate for the three well tieback has been generated by TechnipFMC based upon the study work completed during the Concept Engineering phase. TechnipFMC advises a cost accuracy range of +30% / - 20%. No contingency is included in the cost estimate due to the detailed nature of the work performed and the fact that the entire scope is largely under the control of TechnipFMC (Procurement through to Installation).

The Karish SURF budget is US \$206.8 mln.

Included within the budget submission are the following:

- Project Management and Engineering Design: US\$17.3 mln
- Procurement of Equipment and materials: US\$104.4 mln
- Fabrication and Manufacturing of equipment: included in the above
- Installation: US\$85.1
 - 4-slot manifold and suction pile c/w pigging loop
 - 2-off 10"NB Risers c/w associated ancillaries and riser base
 - 1-off dynamic umbilical
 - Subsea controls
 - Rigid spool and umbilical tie-in systems
 - Tow of FPSO from local port to Field

The following are the main cost elements of the Subsea and Umbilical basis of estimate: -

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Umbilical Procurement

An RFQ has been prepared and issued to Technip Umbilical Systems. The subsequent quotation has been reviewed and clarified as applicable in order to achieve a compliant technical and commercial proposal.

Line pipe Procurement (and associated ancillaries)

An MTO has been prepared in the engineering phase, and RFQ's have been issued to approved suppliers/vendors. The subsequent quotations shall be reviewed and clarified as applicable in order to achieve a commercially optimised, technically compliant proposal.

Miscellaneous Procurement / Fabrication

Where appropriate, RFQ's have been prepared and issued to approved suppliers/vendors. The subsequent quotations have been reviewed and clarified as applicable in order to achieve a commercially optimised, technically compliant proposal.

For lower value procurement items, recent historical pricing has been used, and assessed and adjusted accordingly, dependant on the scope of work.

Installation Vessel(s)

The installation vessel(s) cost estimate has been built up using the following methodology:

Spread List: a comprehensive equipment list has been prepared in order to build up an accurate spread required for any particular vessel operation. The equipment pricing used is a combination of internal catalogue and external third party equipment day rates.

Personnel on Board (Marine/Construction/Project Specific Crew): Engineering, in conjunction with our vessel management group (TMOS), has prepared a list of personnel required in order to build up an accurate Personnel On Board (POB) for any particular vessel operation. The pricing used is based on internal catalogue rates or recent project third party pricing.

Offshore Schedule: Planning personnel have prepared an offshore installation schedule using norms built up from previous projects with similar scopes. This offshore schedule has been applied to the spread/personnel rates in order to build up an installation cost estimate.

Installation Ancillaries: Installation ancillary requirements and previous project pricing has been used to build up the cost estimate.

The cost estimate will be further developed as the level of definition and cost accuracy increases during the pre-FID engineering phase.

8.2.3 FPSO development

Based on the work undertaken by Genesis during the Concept Engineering phase and Kanfa/Inocean during the FEED phase, TechnipFMC has generated a cost estimate for the hull, topside and integration work scopes. TechnipFMC advises a cost accuracy range of +30% / -20% including a contingency of 15% to cover items not yet included formally in the analysis. The cost estimate for the hull reflects initial unit rates received from construction yards in China, Korea and Singapore. The cost estimate used in the FDP assumes construction of the entire FDP in China.

The FPSO topsides cost estimate is US\$ 303.6 mln. The FPSO hull cost estimate is US\$ 205.6 mln. The FPSO mooring system cost estimate is US\$ 57.9 mln. The cost of transporting the FPSO from China to Israel is included under the hull cost. The cost of installing mooring supports is part of the SURF cost estimate.

Included within the budget submission are the following:

- Procurement of Equipment and Materials
- Fabrication and Manufacturing of topside equipment

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- Construction of FPSO Hull
- Hull and Torside integration
- Sail from yard to local port

The detailed build-up of the FPSO cost estimate is included as an attachment. An alternate cost estimate assuming topside fabrication and integration in Singapore is also included.

The cost estimate will be further developed as the level of definition and cost accuracy increases during the engineering phase.

8.2.4 Dry-gas export line

TechnipFMC has prepared a cost estimate for the 24"/30" dry gas pipeline from the FPSO to the tie in point to the INGL transmission system at Dor including necessary block valves and metering system. This has been broken into section representing the offshore section to the Dor beach, the beach crossing and the onshore section from Dor Beach to the Dor Valve Station. The current estimate does not include the "interface facility" at the 10km location as discussed above.

8.2.4.1 FPSO to beach crossing

The budget estimate for the offshore pipeline is US\$ 167.1 mln. The accuracy range is advised as +30%/-20% with no contingency added.

Included within the budget submission are the following:

- Procurement of Equipment and materials: US\$ 16.9 mln
- Fabrication and Manufacturing of equipment: US\$ 73.6 mln
- Installation: US\$ 76.5 mln
 - Shallow water lay barge
 - Trenching and backfilling – shallow water section
 - Rock Dumping
 - Deep water S-lay vessel
 - S-lay vessel support barges and tugs
 - Line pipe storage, handling and logistics
 - Shore based precommissioning operations

The cost of the 24"/30" line from the FPSO to the 10km interface point with INGL is estimated by TechnipFMC at 70% of the overall cost (US\$ 117 mln). Hence the cost of the shore approach is 30% of US\$ 50mln. The shore approach is more costly/km than the deep-water section due to the need for trenching and burial activities.

The cost estimate will be further developed as the level of definition and cost accuracy increases during the engineering phase.

8.2.4.2 Beach crossing

The cost of the HDD installation of the 30" pipeline under Dor beach is currently estimated by TechnipFMC to be US\$ 42.4 mln. This estimate is less mature than the other elements and will be further worked in the next phase.

8.2.4.3 Onshore pipeline and facilities

TechnipFMC has only undertaken initial design work associated with the onshore pipeline. This section of the project is less mature as full definition requires further integration with INGL and the Noble's Leviathan development. Currently the Feasibility level cost estimate generated by Granherne is therefore retained. The cost estimate of this element is US\$ 3.5 mln with an accuracy of +40%/-25%.

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8.2.4.4 3rd party access to the 24"/30" dry-gas pipeline

As discussed in Section 7, the Israeli government has indicated that the State will fund the Karish dry-gas export line from the 10km point to the tie in with the existing INGL pipeline system. This section of the line will be operated by Energean but owned by INGL and 3rd parties will have access. Based on the above the currently estimated cost of this final 10km of the offshore section, plus the onshore elements is US\$95.9 mln.

It should be again noted that within the economics presented in this FDP these costs are conservatively attributed to Energean. They will be removed and the economics updated once firm plans for INGL's ownership of this section has been agreed.

8.2.5 Tanin development

TechnipFMC has prepared a high level cost estimate for the Tanin sub-sea production system as defined in section 7. This includes a remote manifold with clustered wells, two 12" NB pipelines with tie-in points located in Block 12 and two risers that tie into pre-install hang offs on the Karish FPSO.

This equipment is estimated to cost (installed) US\$ 282 mln. The accuracy of this estimate is +30/-20% with no included contingency given the level of definition achieved to date.

In addition to the SPS cost an allowance of US\$ 140 mln has been included to cover the provision of the DEH system including a 4th FPSO power generator. This estimate is based on early data from vendors.

It is currently assumed that 3 wells will be required to develop Tanin Block A, Wells will later be added for the C and B Block developments. As these wells are slightly deeper than those required for Karish Main and the C Block well will require a horizontal OHGP, US\$ 60 mln has been allowed in the budget. This is 15% greater than the Karish Main wells. Tie-back costs of \$20 mln per mini-cluster (C Block) or per standalone well (B Block) are also included.

Although the Tanin development covered by this FDP is based on Blocks A, B and C, it is clear that both Blocks E and F (undrilled at present, but offering very low exploration risk) offer more cost effective development targets. It is probable that these structures will be drilled prior to the Tanin development being sanctioned. These structures would require just one development well each. The exploration wells would be employed as development tie-backs.

8.2.6 Other costs

Work over costs to convert the three Karish Main C/D producers into B reservoir producers of US\$ 54 mln (US\$ 18 mln/well) have been included.

Costs for developing the Karish North prospect post development have been prepared but are not fundamental to the analysis included in this FDP.

8.2.7 Cost Risk Assessment

A full cost risk assessment with the objective of developing a probabilistic forecast will be undertaken at the end FEED. Currently deterministic scenarios are employed to investigate impact of CAPEX on economics.

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9 Project Execution Planning

Energean will develop a full Project Execution Plan (PEP), in collaboration with its main contractors, which shall describe the project structure, processes, controls, and relative priorities, which Energean will adopt to manage all phases of the Development Project. This shall include the development from the Design phase, through the Execution Phase, and into the Produce Phase, which encompasses engineering, procurement, construction, start-up and commissioning, first gas production and project close out. Key elements of the PEP are outlined in the following sub-section for each project element.

The PEP will be designed to perform the following functions:

- To ensure that contractual responsibilities and authorities have been planned for, are clearly identified, have adequate resources, and are understood by personnel responsible for their performance,
- To demonstrate how the project will be executed safely, with minimum risk to people and minimal environmental impact,
- To define the project scope, objectives, drivers, and criteria against which the project will be measured,
- To describe the approved budget and schedule,
- To describe the contract management strategy,
- To describe the key project risks and mitigation strategy,
- To describe the project governance, Project Management Team (PMT) organisation (demonstrating adequate resource), PMT roles and responsibilities, and identify contracts and interfaces that will be managed by the PMT Members,
- To describe the management of Quality and HSE with reference to separate specific plans for further detail,
- To outline mechanical completion, commissioning and Duty Holder Handover / commissioning plan,
- To describe the project systems and procedures including schedule and cost management,
- The PEP should be carried out in accordance with the PMO Management System, Policies, Standards and Procedures,
- The PEP should align and interface with all key contractors and sub-contractor's execution plans which have been provided as part of the contract submission.

This section of the Karish and Tanin FDP provides an initial version of the PEP. It will be further enhanced and refined as project detail increases in the months leading up to FID.

9.1.1 Contracting Strategy

The Karish and Tanin Contract Strategy has been developed with the aim of minimising the interfaces to be managed during project execution. Failure to manage interfaces is one of the main reasons why projects are delayed or run over budget. Traditionally projects are broken down into small packages suitable for execution by specialist vendors. These packages are then tendered with the lowest cost technically acceptable company being awarded the work. Whilst this approach leads normally to the lowest price it tends to maximise the number of contracts and hence the interfaces. To win tenders contractors tend to "under-bid", i.e. limiting their guaranteed profit margin. This means that they are incentivised to seek variation orders to increase their scope and maximise profits. The best way to obtain variations is when interfaces with other contractors are sub-optimally managed.

Energean Israel is a relatively small company. A large Operator often has an internal resource pool of project staff to call upon. These staff are available to manage project interfaces that are generated by a traditional approach to contracting. The contracting strategy for Karish takes cognisance of Energean's limited internal resources as well as its desire to prioritise "value" above cost. Value is maximised by reducing technical risk and accelerating schedule rather than simply by attempting to reduce contract awards to the lowest possible level.

This approach of minimising interfaces was applied to each element of the project, namely:

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- Drilling of the 3 development wells,
- Design, construction and installation of a subsea gathering system,
- Development of a new FPSO,
- Provision of a pipeline to shore,
- Operations of the Integrated Production System and
- Management of HSE risks.

The Contracting Strategy applied to each of these project elements is described below. An overall Work Breakdown Structure for the venture is illustrated in the attached figure.

9.1.1.1 Drilling Contract Strategy

If possible Energean will award a single contract to cover the hire of a Drilling rig, Provision of Integrated Drilling Services and supply of necessary logistics support (vessels and shore base). There are a limited number of entities that supply this type of overall integrated drilling solution.

As the number of entities able to satisfy this approach is limited Energean will also seek offers based upon a more traditional approach, i.e. award of separate contracts for a Drilling Rig, Integrated Drilling Services and Logistics (probably split into marine, air and land activities). Tendering for the former two elements has commenced whilst proposals have already been sought for logistics support.

Energean does not plan to break Drilling Services into discrete services or define a number of bundled packages. Its intent is to select either Schlumberger, Baker Hughes or Halliburton via a competitive tender followed by negotiation. Award will be to the company that identifies the best overall method of managing the batch drilling of the three wells.

9.1.1.2 Engineering Contracts: SURF, FPSO delivery, Offshore Pipeline

As a result of the conclusions drawn at the conclusion of the Feasibility-stage and following a subsequent competitive tendering exercise, Energean selected TechnipFMC as its preferred engineering partner for the non-well elements of the project. The main advantage of using TechnipFMC is that it actually owns many of the companies that must work seamlessly together to execute the envisaged EPCmIC contract. The alternatives considered were Alliances of individual entities, some of which remained relatively untested.

A contract with TechnipFMC has so far been agreed for Concept Engineering and FEED. The full EPCmIC contract will be negotiated during the execution of FEED using open book procedures.

- **E:** TechnipFMC would be responsible for Detailed Engineering
- **P:** Procurement (including provision of equipment fabricated by Technip companies, e.g. FMC and Coflexip)
- **C:** Construction of the SURF and pipeline components that can be supplied via Technip companies
- **m:** Management and supervision of the FPSO fabrication contract within the selected fabrication contractor's yard(s)
- **I:** Installation using Technip vessels
- **C:** Commissioning of the integrated system

FMC will supply all wellheads, X-mas trees, manifolds, separators etc. Technip will fabricate all risers, umbilicals and suction piles and provide installation vessels for the SURF and Deep water pipeline scopes.

9.1.1.3 FPSO Fabrication

TechnipFMC will design the new-build FPSO using specialist entities within their organization. The hull will be designed by Inoceen in Oslo to a design that has been employed previously and which has been classified by DNV-GL. Topsides will be designed by Kanfa in Oslo. Kanfa specializes in the design of simple FPSO's for marginal fields and has worked extensively with Inoceen in the past.

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TechnipFMC will be responsible for selecting the construction yard or yards to fabricate the FPSO based on a short list agreed with Energean. These yards are based in China, Korea and Singapore.

FEED work commenced prior to the completion of the concept phase to enable early engagement with available yards. Work scopes have been released to the short listed yards in May 2017 and it is expected that a yard or yards will be chosen in July 2017 so a firm price for the FPSO can be incorporated into the TechnipFMC EPCmIC contract to be agreed in October prior to FID.

It is probable that the hull will be built in any of the three countries selected with the topsides being built in Singapore and their integration with the hull being at the same location.

9.1.1.4 Onshore pipeline and beach crossing

TechnipFMC will manage the design of these elements but will subcontract their execution to avoid the need for building an organization in Israel. The onshore pipeline and the two valve stations will be built by a local Israeli engineering company. The beach crossing will be drilled by a company that specializes in this type of technique.

It is possible that the shallow water pipeline section (to the 10km position and the INGL interface manifold) may be installed by the TechnipFMC G-1200 vessel or a shallow water barge mobilised from the region.

9.1.1.5 Operations Management

Energean will select early in the next phase an internationally recognized company with whom it will partner to build the Operations and Maintenance organisation for the venture.

9.1.1.6 HSE management

Energean has selected ERM to provide support services with regards Health, Safety and Environmental Management. This will include development of an ESIA as well as a "Safety Case" for the development as per the European Offshore Safety Directive.

Table 9-1: Work Breakdown Structure

Project	Karish - Tanin Phase 1 Development
Doc Title	Work Break Down Structure - Simplified
Status	Approved for use
Date of Issue	22 May 2017
Author	Energiean

			Phase A			Phase B						Phase C		Phase D			
Assets	Sub assets	Project Mngt	Feasibility	Concept Select	FEED	Detailed Design	Procurement Long Lead (if Applicable)	Procurement	Fabrication/ Construction	Construction Mngt	Integration/ Pre-Comms	Tow	Installation	Commissioning	Start Up	Certification	Note
Wells											N.a						
SPS	Well Head & Trees										N.a						
	Manifolds										N.a						
	Control Data Management										N.a						
SURF	Sub Sea Umbilical										N.a						
	Risers																
	Flowlines/Spools																
FPSO	Topsides																
	Accomodation & Evac																
	Mooring																
	Hull																
Export Pipeline Deep + Continental Shelf	Pipeline																
	Offshore INGL subsea manifold																See note 1
Export Pipeline Shallow+Shore	Shallow water + Beach Crossing																
	Onshore+Metering Station																See note 2

Contract Holder	Technip / Technip subcontractors
	Energiean-Israeli JV & subcontractors

Note	
1	The INGL subsea manifold (ISM) is currently uncertain and will depend of the final agreements between Energiean and INGL
2	The onshore pipeline section(~2km) and metering station at DVS is potentially going to be under INGL responsibility

9.1.2 FEED and Detailed Design

Within the contracting strategy for the Karish and Tanin development the FEED/Design phase is crucial in developing the FPSO, SPS and SURF design, execution strategy and lump sum cost that will be used as the basis for the final investment decision and the subsequent EPCmIC and O&M contracts. It therefore inherently represents the stage of the project where Energean have most influence and shall be steered accordingly by the project team.

To ensure success of this phase, it is paramount the interfacing elements of the FPSO, SPS, SURF and Installation contractors work in parallel to facilitate the ease of interface management. Energean's contract strategy helps to minimize interfaces and risks, through contracting a single entity that is responsible for all scopes of work, in addition to making early selection decisions for subcontractors and major equipment suppliers, in order to integrate them into design and execute phase. This strategy shall help ensure optimization of cost and schedule.

FEED phase shall be used to give enough definition for the contractors to commit to a lump sum cost, thus allowing Energean to sanction the EPCmIC phase of the project development. In addition to this, accelerated FEED has been carried out to give more accurate estimated costs and schedules for the EPCmIC phase, including key Long Lead Items and yard rates.

To ensure stakeholder alignment throughout, Steering Committee meetings will be held on a monthly basis.

During FEED the following key Regulatory and Compliance activities shall be carried out to demonstrate confidence of achieving compliance: -

- Appoint and engage with IVB,
- Engagement with Classification Society,
- Submission of Design Notification,
- Class Approval in Principle,
- ESIA.

9.1.2.1 Cost Estimating

The FPSO FEED will be carried out using an Open Book Estimating (OBE) principle to enable Energean to maintain oversight to the development of the design and associated cost estimates based on firm offers from key suppliers and subcontractors through to the fully built up costs for the full EPCmIC, of which the main contractor will convert to a lump sum price, as input to the project sanction decision.

The contractor shall be responsible for managing this process with close involvement of Energean through an agreed process with the aim of approaching the cost in a stepwise approach with no surprises in the final formal offer.

9.1.2.2 Base Case

The FEED will develop the design, building on the Pre-FEED and accelerated FEED work carried out by TechnipFMC to define the final configuration including all the SPS, SURF and FPSO, i.e., accommodation, moorings, anchors, topsides, marine and off-loading facilities. The FPSO will be based on an existing design by Inoceen (TechnipFMC subsidiary), spread moored, with 2 riser balconies, with around 11,000T of topside modules.

Key areas are identified against each area below:

9.1.2.2.1 Technical Safety

- Technical Safety & Environmental Studies
- HAZID
- ENVID

9.1.2.2.2 Hull & Marine

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- New build hull design development
- Yard Selection
- Major equipment supplier selection

9.1.2.2.3 Topsides

- Process Philosophies
- Material Selection Studies
- RAM Analysis
- Yard Selection
- Major equipment supplier selection

9.1.2.2.4 Risers and Mooring

- LWSCR Riser fatigue analysis
- Interfaces with the SURF, SPS and Installation scopes
- Flow Assurance interfaces
- Mooring line calculations
- Riser balcony location

9.1.2.2.5 Execution Planning

- Constructability studies
- Design for installation

9.1.2.2.6 Operations & Maintenance

- Develop the O&M Management systems
- Develop O&M plans to support robust OPEX budget covering operation and maintenance costs.

9.1.2.3 FEED Execution Strategy

The FPSO FEED shall be centered at the contractor's, or their design contractor's, primary site. During FEED, Energean will work in a collaborative manner with the Contractor in common offices.

The Contractor shall perform the work in accordance with the jointly developed FEED scope, to the extent set out in and subject to the approved CTRs.

Where technical changes are identified by the Contractor, Company or others (e.g. IVB) a suitable change management process shall be implemented to action and track the change, to ensure the change is propagated through the development design (together with its interfaces) and to update deliverables (in line with agreed project milestones). This process should allow the closure of changes by the conclusion of FEED to the agreement of the Company and Contractor.

It is envisaged that key Energean personnel shall either relocate, or have regular visits to the Contractor's FEED Execution location. During this time Energean will gain a better understanding of how effective the dynamic of working together is, and will plan the PMT for the Project Execution Phase accordingly.

Rigorous Interface management is key to the successful delivery of the EPCmIC and subsequent operation and maintenance of the Karish and Tanin Development. Energean's major contractors shall be responsible for interface management, and within and at the boundaries of Contractor's own scope and identification, planning and resolution of its interface data requirements. A Project Interface Management Procedure shall be developed during FEED, and shall be used to document all significant interface issues such as requests for documentation / information, resolution to queries, technical queries and deviation requests, with the following key interfaces: -

- Drilling and Subsea.
- Subsea and FPSO

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Within each of these areas there are highly detailed and specific interfaces that if not correctly managed will present significant non-performance effects impacting Cost, Schedule and Value, in addition to Safety and Operability.

An interface register shall be developed during early FEED, and will be maintained throughout the project, consisting of a series of worksheets prepared for each interface company.

9.1.3 Permitting and approvals

The Karish and Tanin Project will apply for all relevant permits as required under Israeli Regulations, which will include, but not be restricted to:

- Operations Permit,
- Poisons Permit,
- Discharge Permits (drilling cuttings, pipeline dewatering, produced water etc.),
- Marine Operations Permit,
- Air Operations Permit (including security clearance, dangerous goods and medevac),
- Onshore permits,
- Pipeline Crossing,
- Business Permit,
- Building Permit.

Energean will be responsible for the management of permits and approvals directly, and has already hired an experienced Israeli engineer to manage this critical element of the project.

9.1.4 Karish SURF development

9.1.4.1 Project Organisation

Following project award, the management of the Karish portion of the EPCmIC contract will be performed by a fully dedicated Project Management team lead by a Project Manager who will be responsible for the preparation, organisation and management of all project activities.

The Project Manager will be assisted by a Project Team that will finalise the remaining detailed engineering, as well as the construction, organisation and execution aspects of the work. This team will have the overall responsibility of preparing plans and procedures that will control all phases of the work, based on an approved Project Construction Schedule.

Within the Project Team, the Project Engineers will be responsible for the execution of a portion of the overall scope of work as decided by the Project Manager.

9.1.4.2 Project Controls

The Project schedule will be further developed to detail the sequence of operations throughout the project (Engineering, Procurement, Construction, Construction management, Installation and Pre-commissioning/Commissioning). All activities will be monitored by the Project Controller who, together with the Project Manager and Project Engineers will ensure adherence to the Project Schedule.

A system of progress reports will be applied throughout the project lifecycle. Reports will be issued by the Project Manager on a Weekly basis. These reports shall contain schedules, progress updates, QHSE updates, etc. together with other descriptive highlights including concerns and any specific information previously agreed between TechnipFMC and Energean Israel.

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9.1.4.3 QHSE Management

The development will be executed in compliance with the agreed Contract and in accordance with the TechnipFMC ISO 9001 Quality System.

TechnipFMC will develop HSSE (Health, Safety, Security and Environment) procedures for the execution of the Project in consideration of the work to be performed in or adjacent to operating facilities. All the personnel mobilised will attend a safety and environmental awareness briefing/induction, before commencing any work.

An experienced QH&S (Quality, Health and Safety) Co-ordinator will co-ordinate all quality, health and safety matters and procedures applicable to the project. Also involved will be an experienced Environmental Co-ordinator who will co-ordinate all environmental matters and will assess compliance with the Environmental Impact Assessment recommendations and monitoring requirements. The respective plans relating to Health and Safety, Quality and Environmental Controls will be prepared for approval by Energean.

TechnipFMC, along with any subcontractors, will accomplish all engineering, procurement and construction activities. TechnipFMC intends to engage key subcontractors for the following activities:

- Line pipe procurement and Coating,
- Coated Line pipe Transportation,
- Spool Fabrication,
- Pre-Commissioning,
- Commissioning.

TechnipFMC will be responsible for the co-ordination and supervision of its subcontractors.

9.1.4.4 Engineering and Engineering Locations

Any remaining engineering required to be performed post Pre-FID engineering (detailed design and construction engineering) will be carried out by TechnipFMC using in-house regional centres of expertise for the various deliverables, including vessel delivery teams for the offshore scopes of work and product delivery groups for the individual work packages.

9.1.4.5 Procurement and Procurement Locations

In the case of an EPCmIC Project, the Project Team is typically assisted by a Procurement Co-ordinator in managing the interfaces between the Engineering, Procurement and Transport departments and the Suppliers themselves to ensure that the procurement of Project materials is in accordance with the project schedule. In particular, the Procurement Co-ordinator:

- Ensures that Engineering produces the documentation necessary for issue of the Purchase Requests (P.R.) at the planned deadlines,
- Prepares a Procurement Plan to track all procurement activities for the project,
- Participates with the Project Team and Supply chain management team in the selection of vendors and subcontractors,
- Receives the expediting and inspection reports, promotes actions with Suppliers should non-conformities be noted in delivery times and the quality of goods being supplied,
- Maintains contacts with the site to verify receipt of materials and to receive possible notifications regarding non-conformities.

The Contractor's procurement activities include the issue of enquiries to selected vendors, from the approved vendor list, receipt of quotations, preparation of the commercial bid evaluations and order placement.

It is expected that the following major equipment will be procured from the following locations:

Table 9-2: Major Equipment Process Summary

Equipment	Description	Provider	Location
Manifold	4-slot comingling manifold	TechnipFMC	Kongsberg, Norway
Risers (Line Pipe)	2-off 10" NB Risers	TBC	Europe
Risers (Coating)	55mm Solid PU	TBC	Europe
Umbilical	Multi-core Power, Communications and Chemical Injection	TechnipFMC	Newcastle, UK
Driverless Connectors	U-CON type connector	TechnipFMC	Kongsberg, Norway
Controls	Manifold and Tree controls	TechnipFMC	Kongsberg, Norway
Trees and Wellheads	Horizontal Tree	TechnipFMC	Dunfermline, UK
Tie-in Spools	Single bore rigid spools	TBC	TBC

Note: TBC items will be further defined as pre-FID engineering finalises the scope of supply

9.1.4.6 Offshore Construction and Installation

Each vessel Offshore Construction Manager will be responsible for the coordination and management of the offshore installation activities with the assistance of coordinators and supervisors for specific tasks. The installation vessels that TechnipFMC intend to mobilise for the execution of the Karish infield installation activities are shown below.

Table 9-3: Installation vessels to be utilised for Karish infield scope

Vessel	Scope
Skandi Arctic	Umbilical installation, Manifold Installation
Deep Blue	Production Steel Lazy Wave Risers
North Sea Atlantic	Spool Installation, Tie-ins, Pre-commissioning

Note: Vessels specified above are indicative and may change during the pre-FID engineering or project execution phase, depending on specific project requirements and in order to optimise installation schedule and cost.

More information is provided in section 11 attachments specific to the installation sequence.

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9.1.4.7 Survey

A pre-engineering geophysical and geotechnical survey will be carried out to cover the Karish infield development. This activity will include, as a minimum, a detailed bathymetry survey (echo sounder, sonar), a sub-bottom profiler, PCPTs and Box Core samples. Energean shall nominate a contractor to perform a marine investigation, survey and study to support TechnipFMC's installation engineering. The minimum objectives of the Pre-Engineering Survey shall be as follows:

- Verify the oceanographic, meteorological and sea bottom information needed to perform installation engineering, and to construct the Karish SURF and SPS system. The data gathered shall include continuous bathymetric soundings, seabed, imagery, sub-bottom profiling and geotechnical information,
- Identify any subsea feature or oceanographic factor that could affect the structural integrity or stability of the SURF and SPS system,
- Identify any areas that will exceed the allowable and provide data to allow TechnipFMC to reroute or re-position, so that pre-lay intervention is not required,
- All potential obstacles and uneven areas shall be identified in order to allow for further engineering verification.

A dedicated survey vessel(s) will be subcontracted for this activity.

During the installation phase of the project, a pre-installation survey will be performed to identify if any new hazards have arisen prior to installing the SURF equipment.

An As-installed survey will also be performed after installation to monitor the positioning of the equipment installed and capture final positions for the as-built survey. All positions will be plotted on the appropriate survey charts upon completion of the project.

Survey activities will be performed by the dedicated installation vessel for the particular installation activity.

9.1.4.8 Riser Installation

The Deep Blue will mobilise the Steel Lazy Wave Risers from one of TechnipFMC's spoolbases (currently planned to be Mobile, USA, or Evanton, UK) along with the PLETs, Buoyancy Modules and Strakes. Upon arrival onsite, the Deep Blue will perform straightening trials to measure out of straightness, measured at the mid-point between a 6m section of pipe. The Riser will be wet stored until the FPSO is onsite at a later date, so concrete mattresses are pre-installed to protect the Flex joint. A suction pile is initiated for each line installed. The first end PLET will be upended and welded to the pipe on the reel. The 1st end PLET will then be over

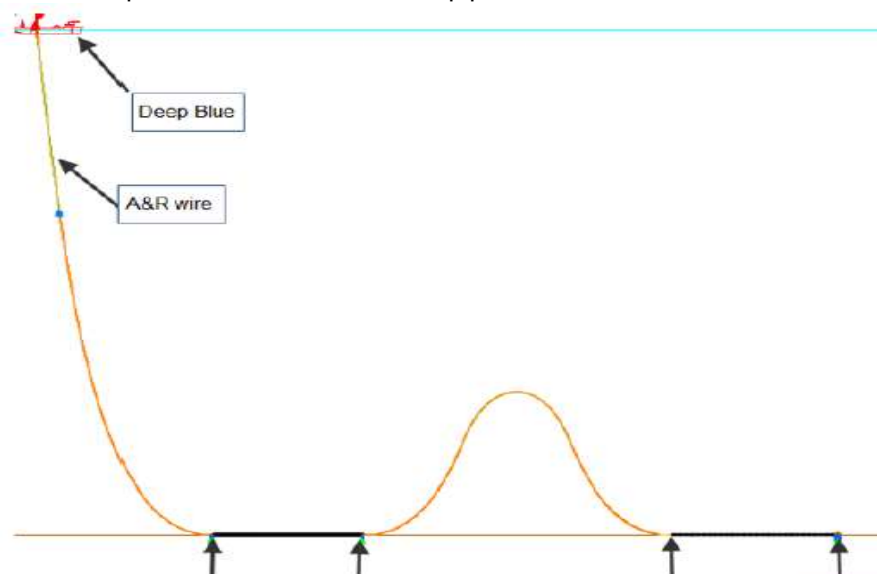


Figure 9-1 Riser installation

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boarded and initiated via the suction pile. The Deep Blue will then move forward paying out pipe as it moves. During this phase Strakes and Buoyancy Modules will be installed. At the end of the pipe the Flex Joint will upended and welded to the pipe. The A&R winch will connect to the Flex joint for over boarding and the Flex joint abandoned on the pre-installed concrete mattresses.

Once the FPSO has been hooked up, the Skandi Arctic will recover the abandoned Flex Joint and cross haul to the FPSO for final hook up. The concrete mattresses will then be recovered.

9.1.4.9 Umbilical Installation

Each umbilical will be installed from a carousel located on the Skandi Arctic. The umbilical will be passed over the Tilttable Lay System and held using a series of tensioners. These tensioners will pay out the umbilical as the vessel manoeuvres forward. The infield umbilicals will be connected to a UTA at each end. The UTA will be installed using the Skandi Arctic crane.

9.1.4.10 Manifold Installation

The manifold will be installed by the Skandi Africa, using a single point lift as follows:

- One lift for the manifold foundation;
- One lift for the manifold module.

The suction pile will be supplied with lifting hooks which will be fitted with WROV operable latches. The pile will be over boarded in a horizontal position and lowered to a depth of approximately 15m where it will be upended, ready for installation. A WROV will then close the pile vent hatches and engage the hot stab to commence pumping. A second ROV will monitor penetration into the seabed while the pile is beds into position.

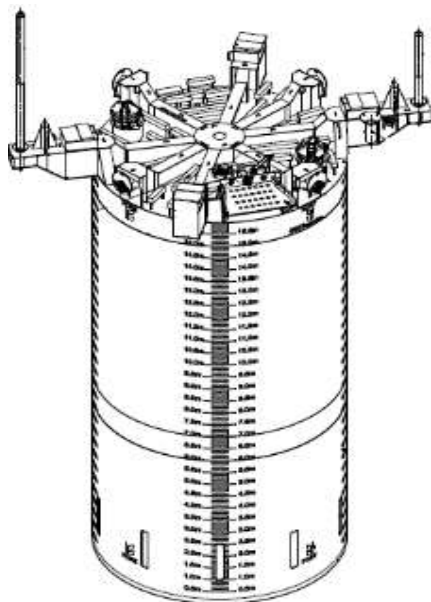


Figure 9-2 Typical suction pile

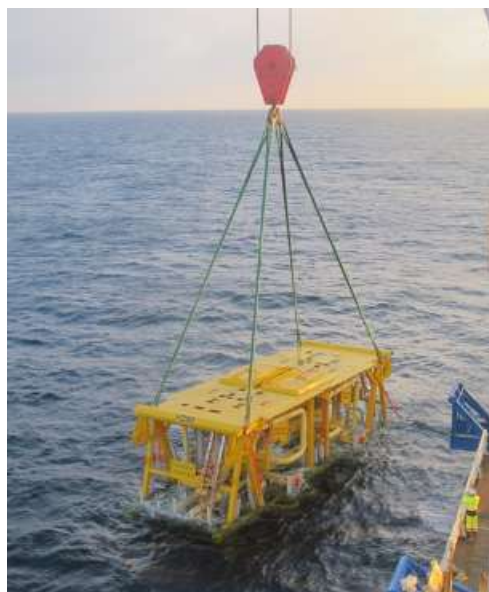


Figure 9-3 Manifold being lifted to location

The manifold will be supplied with lifting hooks in the corners of the structure which will be fitted with ROV operable latches. The manifold will be over boarded 50m clear of all subsea assets, to a depth of 40-50m, where the WROV will hook up onto the rotation rigging. Simultaneously a clump weight will be over boarded to the opposite side of the vessel. The structure and clump weight will be lowered to a depth 15m above the seabed where the vessel will step in to position over the pre-installed suction pile.

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The structure will be lowered into position confirming the location and heading before landing. The slings shall be released from the manifold module's lifting hooks by ROV and returned to the vessel along with the clump weight.

9.1.4.11 Pre-Commissioning

The Pre-installed risers will be flooded, cleaned and gauged, once hook up and tie-in is complete a full Karish system test will be performed from the FPSO. Upon successful completion of this the system will be dewatered.

9.1.5 FPSO development

9.1.5.1 Project management principles

9.1.5.1.1 Project Charter

An FPSO sub-Project team will be established within the larger Karish Development project. This sub-team will develop a Project Charter that act as consolidated commitment from all stakeholders, both internal and external, to execute the project with high emphasis to HSE, whilst delivering quality products on time, and within budget.

9.1.5.1.2 Execution Strategy

The execution strategy will harness synergistic opportunities to work with our contractors in a collaborative and integrated manner. A small core project management team shall be located in engineering office during engineering phase, and shall continue through to start-up, supplemented by additional support during construction and commissioning phases, and on to Israel for start-up and onshore support.

9.1.5.1.3 Execution Geography

The project shall be executed with minimal geographical constraints, which will improve communications amongst all stakeholders and team members. Contractors are to explore all scenarios with regards to execution locations to help maximise opportunities for success.

9.1.5.1.4 Engineering & Procurement

The engineering and procurement for the hull and topsides shall be executed from the same location. The engineering activities shall be worked in conjunction with an agreed schedule, and shall submit documentation well in advance of the commencement of construction activities. This will allow the yards to perform the construction activities in an efficient manner and with a constant base load on the workforce, and will support early procurement of equipment and materials. A local procurement office will be set up at the construction site, in order to act as liaison between package management and construction site, coordination, and perform local expediting and inspection. The local office shall have the ability to procure low value items and top-up materials from local suppliers where necessary.

9.1.5.1.5 Fabrication

Contractor will only utilise sub-contractors that have been approved by Energean, and have a track record of delivering similar projects on time and on budget. Preference will be given to the ability to execute the project within a geographic hub, for hull, topsides, integration and commissioning. The selection process for the fabrication yards is already underway, and shall be finalized during the FEED phase of the project

9.1.5.1.6 Completions

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Mechanical Completion will be carried out in the module fabrication yards, and will achieve a minimum completion progress of above 98% prior to load out for integration yard.

9.1.5.1.7 Commissioning

The pre-commissioning, commissioning and offshore commissioning shall be carried out by the contractor, with assistance from their sub-contractors and vendors. A Zero Carry-Over Work philosophy shall apply. In addition to 100% inshore commissioning completion, all efforts shall be made to minimise offshore commissioning scope, and transferring it to inshore commissioning, i.e. compressor string testing on gas.

9.1.5.1.8 Integrated Team Philosophy

Decision making criteria in selection of contractors shall consider the integrated team approach, and how well the contractor(s) will work with Energean. An integrated team approach will help cement key relationships through the execution of the project.

9.1.5.2 Construction

The contractor shall develop a Construction Management Plan during FEED, and at least 6 months in advance of striking steel, for the following components: -

9.1.5.2.1 Sub-Contractors

Contractor will use pre-approved sub-contractors that have extensive experience in their fields. Preference will be given to utilising major sub-contractors within the same geographical hub.

Any major-subcontractors that are utilised for fabrication works will be approved in collaboration with Energean. Contractor shall develop an individual selection and audit plan for all sub-contractors with contract value above (\$500,000), which shall include, but not be limited to: -

- HSE,
- Quality,
- Performance Record,
- Capacities & Capabilities,
- Regulatory Compliance.

Special attention shall be given to Safety Critical Elements (SCE), ATEX, PED and exotic works.

9.1.5.2.2 Site Supervision Teams

Contractor shall appoint dedicated site supervision teams at each site, headed by a Site Construction Manager. Resource plans will be prepared for each site, which shall be populated by experienced and qualified personnel, and be approved by Energean. These sites shall include: -

- Topsides Fabrication Yard,
- Hull Fabrication Yard
- Topsides Integration Yard,
- SPS/SURF Yard.

It is expected that the contractor shall relocate their PMT to the region of the execution phase, i.e. Engineering & Procurement, and Construction phases, which shall include the following functions: -

- Project Management,
- Administration,
- Document control,
- Project Controls,

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- Procurement.

Energean will mobilise a small oversight management team that shall be co-located with contractor personnel.

9.1.5.2.3 Module Load Outs

Contractor shall develop a procedure for module load outs and transportation to integration yard for bogie transporters, skidding and / or heavy lifting, along with the appropriate civil engineering reports. The procedure shall be approved by contractor's MWS, and verified by Energean's IVB.

9.1.5.2.4 Heavy Lifts

Contractor shall develop a heavy lift procedure for all lifts in excess of 200 Tonne, which shall include module weighing through a load cell arrangement, prior to any lift. Again all procedures will be approved by contractor's MWS and verified by PMO's IVB.

9.1.5.2.5 Integration

Contractor shall develop an integration management plan, which shall include the processes and procedures for Hull assembly blocks, topsides modules (including partial modules, and turret module integration works.

9.1.5.3 Commissioning

Commissioning is the planning and execution of inspection activities required to verify the mechanical completion, pre-commissioning, and commissioning activities, through to system handover and start-up. The contractor shall perform these activities under the responsibility of a designated commissioning manager.

9.1.5.3.1 Commissioning Management Plan

The contractor is responsible for preparing the Commissioning Management Plan. The Commissioning Management Plan will detail the organization of the commissioning, the management of the interfaces with engineering, procurement, construction, planning and offshore production, and the management and progress measurement of the commissioning activities.

The Commissioning Management Plan shall be prepared in close cooperation with the Construction Manager, Engineering Manager and project controls, with details of the constraints and interdependencies on the system commissioning sequence. The plan shall be kept up to date, accommodating any changing priorities as agreed.

9.1.5.3.2 Completions / Commissioning Scope

The completions and commissioning scopes shall be broken into 3 categories, namely: -

- **'A' Scope – Mechanical Completion.** These are the inspection and checks carried out to demonstrate that the FPSO or parts thereof have been fabricated and equipment has been installed as per engineering drawings and specifications. This scope of work shall be defined by the contractor and carried out by the hull and topsides fabrication yards as part of the base construction scope of work. Results of checks and inspections will be recorded on Inspection & Test Records (ITRs), as ITR A's,
- **'B' Scope – Pre-Commissioning.** These are energized or pressurized checks and tests carried out on individual equipment to prove their functionality. This scope of work shall be defined by the contractor. Results of the tests will be recorded on ITRs, as ITR B's,
- **'C' Scope – Commissioning.** These are test running of systems or equipment to demonstrate that completed systems or sub-systems are safe and operable. 'C' scope is not performance

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testing. This scope of work shall be defined and executed by the contractor, with assistance from sub-contractors and vendors where required. Results of the tests will be recorded in Operational Test Procedures (OTP's) or commissioning dossiers.

9.1.5.3.3 Commissioning Dossiers

Contractor shall compile Commissioning Dossiers for each system, to demonstrate that system functions are in accordance with the design requirements, SCE performance standards, and have been accepted by the relevant parties. The contents of the Commissioning Dossiers shall be agreed during the FEED phase.

The Operations Team should accept each system as it is commissioned and should sign off the commissioning dossier accordingly.

9.1.5.3.4 Completions / Commissioning Database

The contractor will use a proven Completions / Commissioning Database, to provide real-time progress tracking, control and management of individual systems, sub-systems and components from the start of completion until system handover, including identification and close-out of punch list items.

The database will be populated with tag numbers for individual components such as mechanical equipment, electrical equipment, valves, instruments and cables, including those within equipment skids following which these tag numbers are linked to sub-systems and systems. The database will also define the inspection and testing requirements for all systems, sub-systems and components.

The Database shall be populated by a Database Administrator in cooperation with the commissioning manager, and completions and commissioning teams. The database shall be updated on a daily basis by the Database Administrator.

9.1.5.3.5 Preservation

Energean's project execution strategy will require the FPSO to be completed and commissioned in the yard, well before the FPSO will be put into service. The strategy will further include an extensive module integration and commissioning period. In order to avoid degradation of the equipment and materials, the contractor shall prepare a preservation plan, under the responsibility of the Commissioning Manager. The preservation plan shall incorporate the specific recommendations from equipment suppliers which will be submitted as part of the Contractor Data Requirements.

The responsibility for active preservation and maintenance of passive preservation falls under the contractor Commissioning Manager up to the moment of system handover, when the contractor operations teams will take over the preservation responsibility.

9.1.5.3.6 Offshore HUC

Contractor's Offshore HUC procedures shall be developed on a system by system and sub-system basis, to demonstrate system functionality against specified design requirements, with the identification of the offshore testing requirements for Safety Critical Elements (SCEs) against Performance Standards, and detail the scope, duration and resources required to complete commissioning offshore. Any potential constraints/clashes with scheduled work shall also be detailed on the Commissioning Plan. These procedures shall be reviewed and accepted by the operations and technical safety teams, in addition to any 3rd party verification required.

All onshore and inshore testing and commissioning shall be optimised, to ensure minimal offshore HUC, and schedule impacts. Special consideration shall be given to onshore gas string testing of compressors.

9.1.5.3.7 System Conditioning

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On completion of commissioning, and prior to the introduction of hydrocarbons, consideration shall be given to the condition of the pipeline and process system, with particular regard to the following:

- Potential for hydrate formation
- Potential for plant upsets during start-up
- Ability to discharge chemicals added to the system
- Cleanliness
- Permits and consents for additives

The as-left condition of the pipelines, valves and process system should be clearly described in handover documentation, as per the flange management process.

9.1.5.3.8 Punch List Management

Items requiring remedial work which have been identified during mechanical completion pre-commissioning and commissioning shall be recorded on punch lists. Category 'A' Punch List items must be resolved before sub-system item can be mechanically completed with signed off ITR A. Category 'B' Punch List Items shall be closed out prior to sign off of operational test pack, and system acceptance. All punch list items shall be identified and closed-out through the completion database.

9.1.5.3.9 Valve Status Matrix

A Valve Status Matrix shall be developed to identify the as-left status of all subsea valves. A video survey shall also be conducted to verify completion of the work scope prior to departure of construction vessels from the field. This is critical for manually actuated valves. The As-Left valve status should be clearly described in handover documentation.

9.1.5.3.10 Integrated Process & Flange Management

Contractor is to develop an integrated process & flange management philosophy during FEED, and agreed by Energean, in order to achieve 100% system integrity. Flange Management Philosophy shall be developed in conjunction with piping design in order to minimise integration spools, flanged connection, field fit welds, and maximise the ease of testing and commissioning.

9.1.5.3.11 Interface with POB and Logistics Plan

The project POB Plan must be integrated with the overall facility POB Plan, coordinated by the Operations Team. The importance of the project POB versus ongoing production operations POB requirements is an issue that needs to be understood and acknowledged by all parties with priorities defined at a senior management level.

The project logistics requirements must also be integrated with the host facility logistics plan to make effective use of supply vessel sailings and helicopter flights.

9.1.5.4 Offshore Hook-up & Commissioning

Prior to sail away, provisional acceptance of the FPSO shall be confirmed on a system-by-system basis, until the agreed 'Ready for Sail-away' condition and their handover is accepted by Energean, Operator and Regulatory authority.

Once Provisional Acceptance has been achieved, then the following shall occur: -

- Issuance of the provisional acceptance certificate.
- Defect Correction Period shall commence.
- The Operator shall become responsible for the day-to-day operation and upkeep of the systems through their offshore HUC work, Start-up and operational phases.

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Offshore hook-up scopes and commissioning procedures will be developed by our major contractor during the early stages of the EPC, including but not limited to the following: -

- Regulatory sign off shall be achieved prior to sail away from designated yard, allowing the FPSO to go straight to field location.
- List of Hook-Up Scope as part of Project proposal strategy and demonstrate throughout Project execution that offshore Scope of WORK has been reduced as much as possible. Onshore/Inshore scope shall be maximised (including dynamic commissioning) to facilitate a timely HUC period.
- All offshore hook-up scopes and offshore commissioning procedures updated to incorporate the onshore completion status.
- Any Prefabricated items for the offshore hook-up.
- Consumables that form part of the permanent work.
- Preservation materials.
- All resources including specialist subcontractors, vendor representatives, EPC Contractor personnel etc. that are agreed to continue to the offshore phase.
- All lubricants (including 1st fills required at yard).
- All data and documents associated with materials and engineered items of equipment procured for hook-up and commissioning.
- All software and software licences.
- All hook-up materials/equipment and commissioning spares.
- Coating materials for final touch-up of coating during installation and hook-up.
- Any temporary lifting and mechanical handling equipment.
- POB increase dispensation.
- Additional life rafts installed on FPSO for increased manpower.

9.1.5.5 Start-Up

Following handover of the systems onshore we shall proceed with the installation, hook-up and commissioning and other preparations in readiness to start the facility. The following Start-up documentation shall be provided:

- Start-up support package detailing all preparation work necessary to prepare all systems ready for start-up (RFSU) offshore.
- Start-up Philosophy updated from the end of FEED version to incorporate the final design and issued for further development into the detailed Start-up Procedure(s).
- List of all materials and consumables required for the start-up.

9.1.5.6 Offshore Acceptance (Final Acceptance)

The Final Acceptance of the work on achievement of the following will be confirmed: -

- The successful completion of the 72-hour performance test.
- All defects relating to contractor works have been corrected.
- The Defect Correction Period has ended.

9.1.6 Pipeline development

9.1.6.1 Engineering and Engineering Locations

Any remaining engineering required to be performed post Pre-FID engineering (detailed design and construction engineering) will be carried out by TechnipFMC using in-house regional centres of expertise for the various deliverables, including vessel delivery teams for the offshore scopes of work and product delivery groups for the individual work packages.

9.1.6.2 Procurement and Procurement Locations

In the case of an EPCmIC contract, the Project Team is assisted by the Procurement Co-ordinator in managing the interfaces between the Engineering, Procurement and Transport departments and the Suppliers themselves to ensure that the procurement of Project materials is in accordance with the project schedule.

In particular, the Procurement Co-ordinator:

- Prepare a Procurement Plan to track all procurement activities of the project;
- Participates
- with the Project Team and Supply chain management team in the selection of vendors and subcontractors;
- Receives the expediting and inspection reports, promotes actions with Suppliers should non-conformities be noted in delivery times and the quality of goods being supplied;
- Maintains contacts with the site to verify receipt of materials and to receive possible notifications regarding non-conformities.

The Contractor's procurement activities include the issue of enquiries to selected vendors, from the approved vendor list, receipt of quotations, preparation of the commercial bid evaluations and order placement.

It is expected that the following major equipment will be procured from the following locations:

Table 9-4: Major equipment procurement locations

Equipment	Description	Provider	Location
SSIV		TechnipFMC	Kongsberg, Norway
Line Pipe	1-off 24"/30" NB Pipeline	TBC	Europe
Line Pipe Coating	3LPP	TBC	Europe
Umbilical	Controls Umbilical for SSIV	TechnipFMC	Newcastle, UK
Driverless Connectors	U-CON type connector	TechnipFMC	Kongsberg, Norway
Controls	SSIV controls	TechnipFMC	Kongsberg, Norway
Tie-in Spools	Single bore rigid spools	TBC	TBC

Table Note: TBC items will be further defined as pre-FID engineering finalises the scope of supply

9.1.6.3 Offshore Construction and Installation

Each vessel Offshore Construction Manager will be responsible for the coordination and management of the offshore installation activities with the assistance of coordinators and supervisors for specific tasks. The installation vessels that TechnipFMC intend to mobilise for the execution of the export pipeline installation activities are shown below.

Table 9-5: Installation vessels to be utilised for the export project scope

Vessel	Scope
Skandi Arctic	Umbilical installation SSIV Installation
Deep Blue	Gas Export Steel Lazy Wave Risers
G-1200	Deepwater Pipelay (WD 120m-FPSO)
G-1200 (TBC)	Shallow water Pipelay

9.1.6.4 Survey

A pre-engineering geophysical and geotechnical survey will be carried out to cover the export pipeline development. This activity will include, as a minimum, a detailed bathymetry survey (echo sounder, sonar), a sub-bottom profiler, PCPTs and Box Core samples. Energean shall nominate a contractor to perform a marine investigation, survey and study to support TechnipFMC's installation engineering. The minimum objectives of the Pre-Engineering Survey shall be as follows:

- Verify the oceanographic, meteorological and sea bottom information needed to perform installation engineering, and to construct the Karish SURF and SPS system. The data gathered shall include continuous bathymetric soundings, seabed, imagery, sub-bottom profiling and geotechnical information;
- Identify any subsea feature or oceanographic factor that could affect the structural integrity or stability of the SURF and SPS system;
- Identify any areas that will exceed the allowable and provide data to allow TechnipFMC to reroute or re-position, so that pre-lay intervention is not required;

All potential obstacles and uneven areas shall be identified in order to allow for further engineering verification.

Dedicated survey vessels will be subcontracted for the nearshore and offshore aspects of this activity, as required.

Prior to pipe-lay, a pre-lay survey will be performed to identify if any new hazards have arisen prior to installing the pipeline.

Touch down monitoring will be provided from the G-1200 when required and in particular at start up and over any cable crossing. The ROV will monitor the position of the pipe during lay.

Upon completion of the pipelay, the G-1200 will perform a stand-alone as-laid survey of the pipeline. This activity will include, as a minimum, the survey of the actual as-laid position of the pipeline on the sea bottom, the identification and measurement of all free spans greater than the allowable free span lengths, condition and free-spans of cable crossings, and a video survey of the pipeline.

In the nearshore the above pre-lay, touch down monitoring and as-laid survey will be performed by a shallow water vessel.

In addition to the offshore portion of the survey, an onshore pre-survey will include as a minimum the identification and marking of Right of Way along with the road crossing and obstacles in general, and the survey of the area to identify pre-construction state. Also, the area where the Horizontal Directional Drilling equipment will be set shall be surveyed. A geotechnical survey shall be performed to verify the soil data provided in the Contract documentation. An approved subcontractor will carry out soil testing in a minimum of three boreholes approximately 30m below ground along the onshore portion of the HDD alignment and also to verify the soil samples along the dredging zone.

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9.1.6.5 Shore Approach Works

All activities herein described will be organised under the responsibility of the Shore Approach Project Engineer from the engineering to the final operation phase. Detailed description of all shore approach construction phases will be developed by the HDD and dredging sub-contractors.

Prior to start of operation activities, the Shore Approach Project Engineer, with the assistance of the Shore Approach Site Representative, will organise the site in order to execute the work according to the approved procedures.

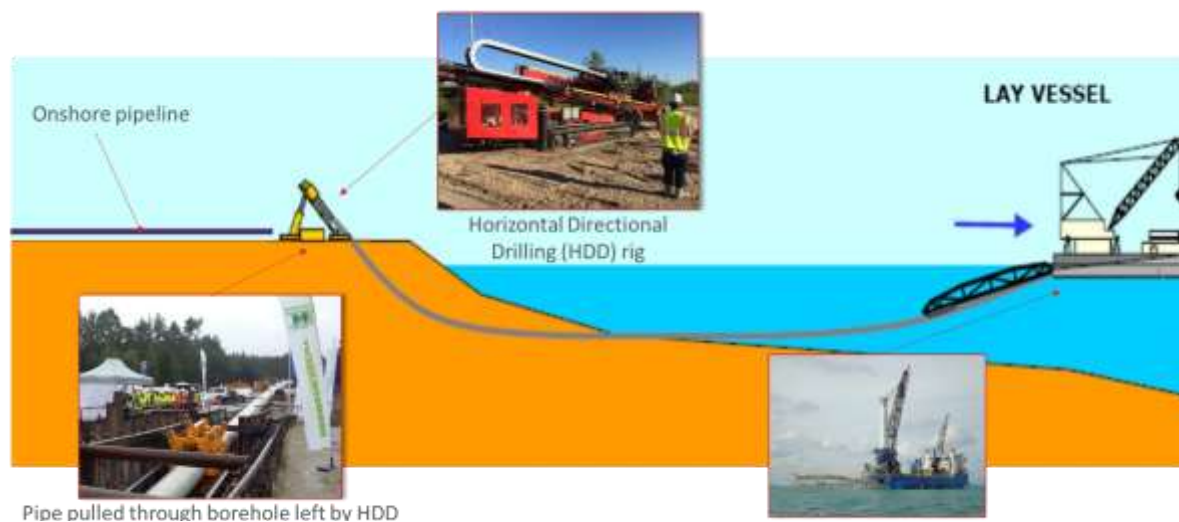


Figure 9-4 Near shore pipelay installation work

During the shore approach construction, the quality, health and safety of the work will be supervised by the QHS Co-ordinator. The environmental impacts will be supervised by the Environmental Co-ordinator. They will clarify with the Shore Approach Project Engineer any corrective actions necessary and report to the Project Manager. Similarly, the safety aspects related to the execution of the operations will be constantly monitored and all safety procedures will be implemented under the responsibility of the Safety Inspector.

In order to avoid any activity in the tidal zone, the shore approach of the pipeline will be carried out using a Horizontal Directional Drilling (HDD) technique. Confirmation of the feasibility of HDD and final details of the HDD will be subject to results of the geotechnical investigation to be carried out in the early phase of the engineering.

The entry point will be as close as possible to the landing point. Final entry point shall be as indicated on the drilling procedure and HDD alignment sheet. Fencing will be set up around the drilling construction site in order to delineate the site and prevent unintentional entry onto the site by the public.



Figure 9-5 Pull-in winch operation



Figure 9-6 Trenching

The HDD shore crossing will be carried out in a single drilled section measuring approximately 1175m in length from the entry point located onshore to the exit point located offshore. The entire drill string length will be approximately 1395m including a 220m long tail string coated with 2" THK concrete which will be over pulled and laid on the seabed after completion of pullback to enable lay barge to recover the pipeline, tie-in and lay offshore.

9.1.6.6 Trenching and Rock dumping

In the nearshore, to water depths of 60m, trenching is required to a depth of cover of 1.2m. A plough will be mobilised after the pipelay has been completed. The plough will be over-boarded and lowered to a depth of approximately 10m from seabed. The plough will be positioned over the pipeline at start of the trench transition. Once the pipeline is engaged the TSV will tow the plough along the pipeline route allowing for a transition of 50m at each end of the trench. The trenching plough will unload the pipeline and recover it to deck.

A separate backfill plough will be over-boarded and positioned over the pipeline at the start of the transition. Once the pipeline is engaged, the TSV will tow the plough along the pipeline route, backfilling the trench. At the end of the trench the plough will unload the pipe and be recovered to deck.

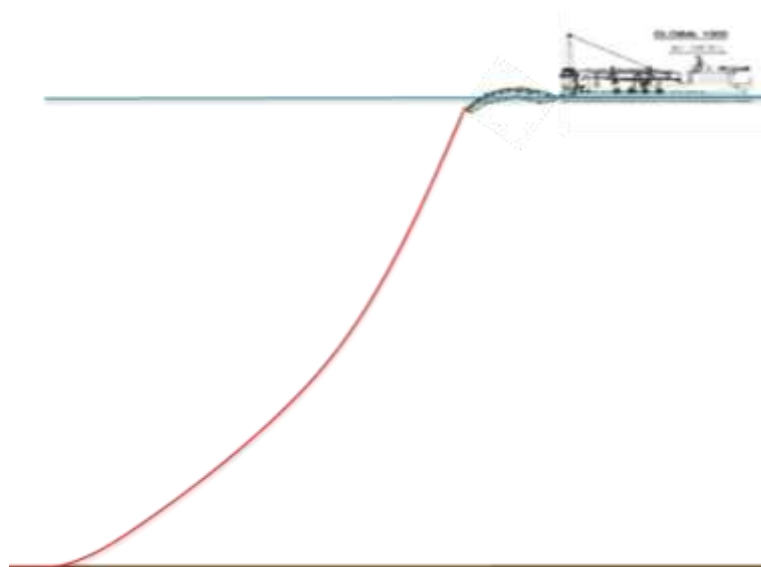


Figure 9-7 S-lay arrangement

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There will be an area of approximately 50m where the pipeline exits the HDD tunnel and starts the trench transition where the pipe will be exposed. This section of approximately 100m will require rock dumping. A dedicated rock dumping vessel will be mobilised, using a side chute the rock will be carefully placed over the pipe to form a berm.

9.1.6.7 Pipelay

Upon completion of the drilling activity, i.e. after the final reaming, the drill string will be used to pull the pipeline inside the drilled hole up to the exit point.

The pulling head welded to the leading end of the product pipe string will be attached to the drill string via a pullback assembly. The pipe string will then be pulled through the hole. Approximately 220m of concrete coated pipe (tail string) will remain on the seabed.

The shallow water vessel will recover the product pipe string and start laying away from the beach. The offshore section of pipe will be laid away from the beach. Pipe lay will be monitored by the barge based ROV. The ROV shall be available for touchdown monitoring at all times.

It is expected that there will be cables to cross in the nearshore, therefore prior to the arrival of the pipelay vessel at the crossing locations a separate vessel will have been mobilised to install the support mattresses at the cable crossing locations. This operation will be performed at a suitable time in advance of the pipelay vessel. The pipelay vessel will lay the pipe over the cable crossing mattresses. This operation will be monitored by the ROV.

The shallow water pipelay vessel will lay to a water depth of 120m where the G-1200 will recover the abandoned pipe and continue laying towards the FPSO location. At the termination point the PLET will be installed with the use of buoyancy tanks to support the capacity of the A&R winch.

On board the G-1200, TechnipFMC intends to provide the following subcontracted services:

- Field Joint coating and Infill Service;
- Survey and positioning Service;
- ROV Service;
- Welding services;
- NDT (Automatic Ultrasonic Testing).

A suitable spread of anchor handling tugs and supply vessels will be chartered for the required assistance to the G-1200 and shallow water pipelay vessel.

9.1.6.8 Riser Installation

The Deep Blue will mobilise the Steel Lazy Wave Risers from one of TechnipFMC's spoolbases (currently planned to be Mobile, USA, or Evanton, UK) along with the PLETs, Buoyancy Modules and Strakes. Upon arrival onsite, the Deep Blue will perform straightening trials to measure out of straightness, measured at the mid-point between a 6m section of pipe. The Riser will be wet stored until the FPSO is onsite at a later date, so concrete mattresses are pre-installed to protect the Flex joint. A suction pile is initiated for each line installed. The first end PLET will be upended and welded to the pipe on the reel. The 1st end PLET will then be over-boarded and initiated onto the suction pile. The Deep Blue will then move forward paying out pipe as it moves. During this phase Strakes and Buoyancy Modules will be installed. At the end of the pipe the Flex Joint will upended and welded to the pipe. The A&R winch will connect to the Flex joint for over-boarding and the Flex joint abandoned on the pre-installed concrete mattresses.

Once FPSO has been hooked up, the Skandi Arctic will recover the abandoned Flex Joint and cross haul to the FPSO for final hook up. The concrete mattresses will then be recovered.

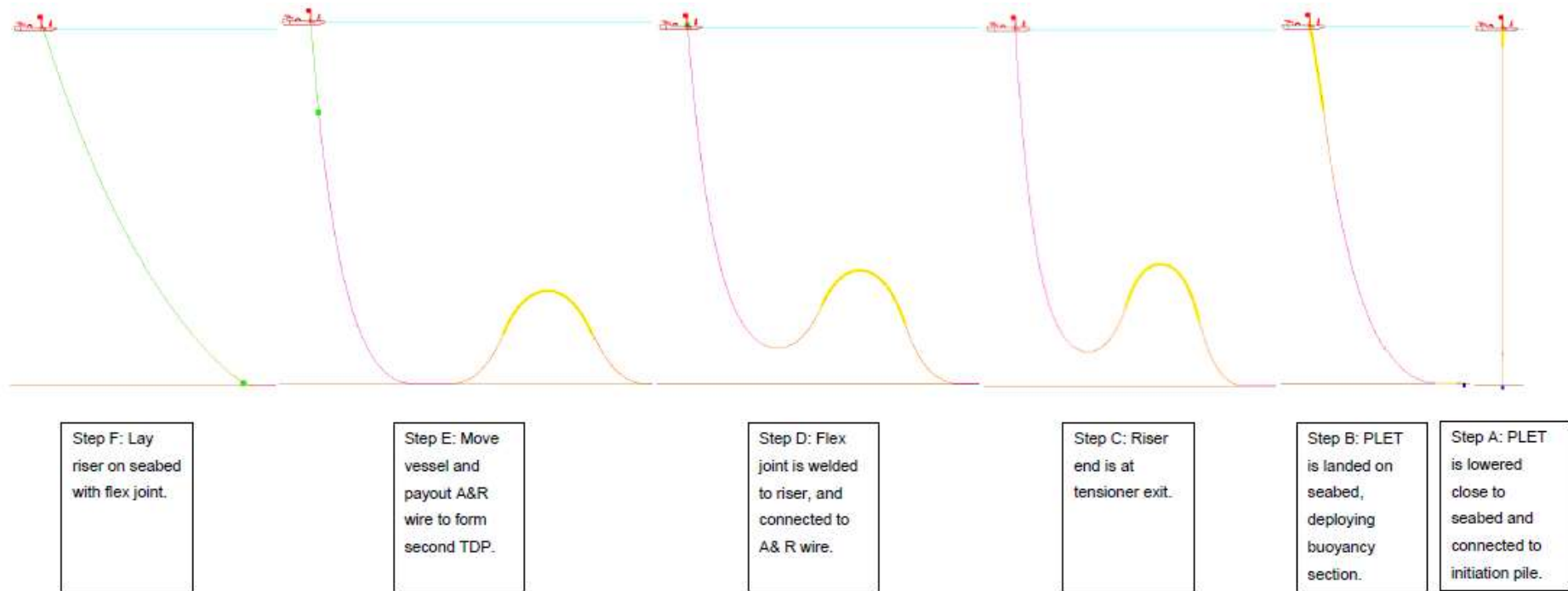


Figure 9-8 Riser pre-lay installation

9.1.6.9 Umbilical Installation

Each umbilical will be installed from a carousel located on the Skandi Arctic. The umbilical will be passed over the Tilttable Lay System and held using a series of tensioners. These tensioners will pay out the umbilical as the vessel manoeuvres forward. The controls umbilicals will be connected to a UTA at each end. The UTA will be installed using the Skandi Arctic crane.

9.1.6.10 SSIV manifold Installation

The SSIV manifold will be installed by the Skandi Africa, using a single point lift as follows:

- One lift for the manifold foundation;
- One lift for the manifold module.

The suction pile will be supplied with lifting hooks which will be fitted with WROV operable latches. The pile will be over boarded in a horizontal position and lowered to a depth of approximately 15m where it will be upended, ready for installation. A WROV will then close the pile vent hatches and engage the hot stab to commence pumping. A second ROV will monitor penetration into the seabed while the pile is beds into position.

The SSIV manifold will be supplied with lifting hooks in the corners of the structure which will be fitted with ROV operable latches. The manifold will be over boarded 50m clear of all subsea assets, to a depth of 40-50m, where the WROV will hook up onto the rotation rigging. Simultaneously a clump-weight will be over-boarded to the opposite side of the vessel. The SSIV Manifold and clump-weight will be lowered to a depth 15m above the seabed where the vessel will step in to position over the pre-installed suction pile. The SSIV Manifold will be lowered into position confirming the location and heading before landing. The slings shall be released from the SSIV manifold module's lifting hooks by ROV and returned to the vessel along with the clump-weight.

9.1.6.11 Pre-Commissioning

Pre-commissioning of the Gas Export System will be completed in two section;

- Gas Export Riser System;
- Export Pipeline System.

The Pre-installed risers will be flooded, cleaned and gauged, once hook up and tie-in is complete a system test will be performed from the FPSO. Upon successful completion of this the system will be dewatered.

The Gas Export Pipeline system will be flooded, cleaned and gauged upon lay on the seabed. Once the system has been tied in a systems test will be carried out from the onshore facility. The Gas Export Pipeline will then be dewatered and dried using a nitrogen purge from the onshore location.

9.1.7 Drilling operations and Well clean-up

9.1.7.1 Introduction

Energean Israel will tender for a suitable drilling rig, drilling services and logistics support facilities in Q2 2017. The intent is to have main contracts identified and negotiated approximately 12 months prior to the commencement of drilling. Earliest spud date for the first of the three planned Karish development wells is planned for August 2018. Energean Israel intends to continue to use Lloyds Register (LR) to provide staff, systems and procedures to support the development of well engineering designs and execution programmes. LR has completed all feasibility and concept select work to date. It is envisaged that the same team of staff will support technical evaluation of the main contracts and then commence the detailed design and procurement for the three deviated development wells.

Although Energean has yet to select a rig it has undertaken a preliminary market evaluation and due to the low level of deep water drilling currently prevailing it is confident that it should be able to access a state-of-the-art sixth generation drill ship with DP and twin derricks for the planned campaign. However the planned tender will also look at availability and price of 5th generation rigs plus 6th generation semis, both moored and with DP to confirm that a 6th generation DP drill ship represents the most cost effective option available. If possible an

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operational rig will be used. Energean intends to avoid new-build units and rigs that have been cold stacked. These would likely lead to increased NPT. The risk associated with each rig will be quantified as part of the technical qualification process.

The description below outlines the steps required to drill, complete and clean up each individual well. During the concept design phase the attractiveness of drilling the wells in batch mode was identified but was not fully quantified. At a minimum batch drilling would save around 7 days on the second and third wells due to reductions in BOP handling operations. In reality services costs would also be reduced by removing repeat mobilisations. Currently such savings have not been accommodated in the assumed daily rate for services. This will be reviewed and the base plan updated during the detailed design phase.

The times identified below are based upon use of a rig equipped with a single derrick. Recent surveys have indicated that it could be expected that actual times would be reduced by approximately 15% should a dual derrick unit be employed. Cost estimates included in the FDP assume that a dual derrick unit can be acquired for the assumed rig day rate.

9.1.7.2 General Operational Steps

The following provides a high level overview of the operational steps involved in drilling, completing and then cleaning up the Karish wells. As mentioned this sequence will be refined during detailed design to reflect batch operations.

- Move rig on to location and position over well.
- Jet 36" conductor to ~70 m of penetration, spacing out for correct LPWHH (Low Pressure Wellhead Housing) stick-up above the seabed.
- Allow conductor to soak.
- Release drill ahead tool and drill 26" hole section with seawater and sweeps to ~450 m into the salt section.
- Displace the open hole to salt saturated water based mud.
- Run & cement 20" casing with HPWHH (High Pressure Wellhead Housing).
- Install and test BOPs and riser onto HPWHH.
- Drill 17-1/2" hole with salt saturated water based mud to ~3,400 m MD. Build angle to ~25° inclination.
- Run and cement 13-5/8" casing.
- Drill 12-1/4" pilot hole section with salt saturated water based mud to the bottom of the D reservoir (to be defined in each well's Pre-Drilling Data Package (PDDP). Build angle to ~40° inclination on directional wells.
- In the first well core will be cut over the B sands to allow the upside pay in this unit to be better quantified
- High resolution logs will be acquired over the full reservoir sequence
- Plug back the 12-1/4" pilot hole
- Drill 12-1/4" hole with salt saturated reservoir mud to the top of the C reservoir
- Run and cement 10-3/4" x 9-5/8" casing.
- Drill 8-1/2" hole section through reservoir to well TD with water based Reservoir Drill In Fluid (RDIF). (Under-ream to 12-1/4").
- Spot solids free RDIF in open hole.
- Install expandable casing over shale below 9-5/8" shoe.
- Install Open Hole Gravel Packer Lower Completion and perform OHGP.
- Perform wellbore clean-up and displace well to completion / packer fluid.
- Set 2 x suspension bridge plugs inside 10-3/4" x 9-5/8" casing.
- Recover BOPs and riser.
- Install Enhanced Horizontal Christmas Tree (EHXT).
- Install BOPs and riser onto EHXT. Pressure test BOPs.
- Recover 2 x suspension bridge plugs.
- Install upper completion on Subsea Test Tree (SSTT) and landing string.

- Flow well to clean-up reservoir sand face.
- Bullhead tubing down to Subsea Safety Valve to brine/ MEG.
- Install and pressure test lower and upper EHXT crown plugs to secure well.
- Move rig to next location.

9.1.7.3 Projected “trouble-free” drilling times without batch drilling – single derrick rig

The following trouble free time estimations have been made for each interval/ phase of a generic Karish development well;

Table 9-6: Projected “trouble-free” drilling times

Prepare to Spud	7 days
Drill 36” x 30” Hole	0.5 days
Run 30” Conductor	0.5 days
Drill 26” Hole	2.5 days
Run & Cement 20” Casing	3.5 days
Run Riser & BOP	7 days
Drill 17.1/2” Hole	2.5 days
Run & Cement 13.5/8” Casing	4.5 days
Drill 12.1/4” Pilot Hole, Wireline, Coring, P&A	23 days
Drill 12.1/4” Hole	4 days
Run & Cement 9.5/8” Casing	7.5 days
Pull BOP, Run X-Tree, Re-run BOP	8.5 days
Drill 8.1/2” Hole (Inc. RDIF Disp.)	8 days
Run & Install Lower Completion	7 days
Run & Install Upper completion	5 days
Well Test / Flow Well & Suspend	4.5 days
Estimated Total Days	99.5 days

9.1.7.4 Drilling uncertainty due to NPT and weather

To this trouble-free estimate P10, P50 and P90 estimates were calculated with Non-Productive Time (NPT) and Wait on Weather (WOW) applied. These were applied at the following rates;

Table 9-7: Range of estimated well timings with NPT and WOW included

Trouble Free	99.5 days
P10 -5% NPT & 0% WOW	104.5 days
P50 - 15% NPT & 5% WOW	119.4 days
P90 – 40% NPT & 20% WOW	159.2 days

9.1.7.5 Total drilling time used to determine FDP well CAPEX

As indicated above these times assume use of a single derrick rig. A dual derrick rig should increase efficiency by approximately 15%. Therefore the P90 – P50 – P10 range with a dual derrick rig would be 135 – 101 – 89 days. The assumed drilling day rate is based upon market intelligence for such dual derrick units.

As explained above this timing includes provision for an initial pilot hole into the reservoir. This is used to collect a core over the B sands and a comprehensive log suite. The pilot hole would be drilled using water based mud and would be abandoned subsequently. A pilot hole allows the top of the C Reservoir to be determined accurately allowing 9-5/8" production liner to be positioned at the bottom of the B/C shale. In the second and third wells it is not planned to collect core, hence the duration of the pilot hole section will reduce from the 23 days outlined above to 17 days. The duration of these later wells will therefore be 129 – 95 – 83.

Initial work undertaken during the concept phase has demonstrated the potential attractiveness of batch drilling the three development wells. The wells will be clustered with a well-well separation of 25m. This makes batch drilling feasible even if a moored rig were employed. At a minimum batch drilling would avoid BOP handling operations associated with the second two wells. The duration of these two wells would therefore reduce by a further 7 days. It is possible other time savings may also be identified during the detailed design phase. Taking this single improvement opportunity into account the timing of the two latter wells would reduce to 122 – 88 – 76.

Based upon the above analysis the projected length of the Karish drilling campaign will be:

- P90 duration: Well 1 = 135 days, Well 2 = 122 days, Well 3 = 122 days; **Total = 379 days**
- P50 duration: Well 1 = 101 days, Well 2 = 88 days, Well 3 = 88 days; **Total = 277 days**
- P10 duration: Well 1 = 89 days, Well 2 = 76 days, Well 3 = 76 days; **Total = 241 days**

9.1.8 Third party verification, well examination and classification

Energean has appointed DNV GL as the Independent Verification Body and Classification Society for the Karish Tanin FPSO and all associated subsea facilities. DNV GL will verify the Safety and Environmental Critical Elements Performance Standards developed for the design and construction of the FPSO Topsides, Subsea Infrastructure, Gas Export Pipeline and Onshore Facilities in accordance with an approved Written Scheme of Verification. DNV GL will also undertake classification of the design and construction of the FPSO Hull, Marine Systems and Mooring in accordance with appropriate DNV GL Rules.

DNV GL in conjunction with NRG will undertake examination and verification of Karish Tanin well design and construction.

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9.1.9 Quality Assurance and Quality Control

9.1.9.1 General Requirements

Quality assurance and quality control shall be put under the responsibility of our major contractors, during the EPC, Installation, HUC, and operational phases for the FPSO, SPS, SURF and T&I scopes of work. Energean shall have access to all associated paperwork and audit trails, in addition to employing an Independent Verification Body.

Contractor's senior management shall actively create an environment where personnel are fully involved in the quality management process and in which the QMS can operate effectively.

All contractors shall operate a formal quality management system (QMS). The system shall incorporate an effective quality assurance (QA) and quality control (QC) programme throughout all stages of design, procurement, fabrication, installation, commissioning, operation of the Services to ensure that all aspects of design, procurement of materials, handling, storage, fabrication and manufacturing, application, installation, commissioning, start up, operation, surveying, inspection and testing fully meet the requirements of the Services Agreement and MBC. Contractors shall ensure that its direct subcontractors, comply with the Contractor's quality plan. Quality plans will identify the key project processes and the quality controls that will be implemented (that are within the Contractor's established management system) to secure the processes (the "Quality Plan").

- The Contractor shall appoint a quality assurance manager (QA Manager) with overall responsibility for QA and QC for the duration of this Agreement. QA/QC engineers/inspectors engaged by the Contractor shall report to the QA Manager.
- The Contractor shall employ only qualified and experienced quality control personnel to conduct inspections throughout the duration of this Agreement.
- Where third party inspection agencies are used (e.g. procurement activities) the agencies must operate a QMS in accordance with the current version of ISO 9001 and have the competence, resources and integrity commensurate with the task.

9.1.9.2 Compliance

The effectiveness of the Contractor's QMS and compliance will be subject to a QA audit process. An audit schedule detailing the QA audit sequence of activities throughout the duration of this Agreement shall be submitted for review and approval, including the Contractor and their direct subcontractors. The following criteria shall be met: -

- Familiar with and agrees to comply with all applicable statutory regulations relating to the Services to be undertaken. All engineering, procurement, construction, fabrication, installation, commissioning and operational work undertaken by the Contractor shall comply with all applicable statutory regulations. Where there is conflict between any statutory regulations and applicable international codes and standards Energean will assist Contractors in obtaining a resolution.
- Any code or standard referred to means the latest edition of that code or standard, including agenda, supplements or revisions applicable. The Contractor shall keep up to date with revisions to these standards as referenced in the Agreement and in this appendix.
- The use of standards which are not publicly recognised as equivalents to those specified by the appropriate international standards organisations, shall be submitted as exceptions to the Agreement for evaluation, approval or otherwise.
- QMS shall be amended as necessary to comply with revised standards within six (6) months of any revision issue date.

9.1.9.3 Material Control

Contractors shall ensure that all materials and equipment to be used during the duration of this Agreement for the Services are in good condition, and meet the design life and performance criteria, and where required shall be equipped with working and calibrated regulators and gauges. An effective material control procedure shall

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be established and implemented providing full assurance that all materials purchased for the Services are new or “as new”, conforming to specification, meet the design life and performance, and are of the specified quality.

A record and documentation system suitable for identifying and tracing all materials requiring traceability shall be established, included in the Quality Plan and implemented by the Contractor and all Subcontractors in accordance with requirements for Identification, Traceability and Certification during the design, manufacture, fabrication, testing, inspection and supply of equipment applicable to all equipment, components, packages and materials.

9.1.9.4 System Requirements

The Contractor shall operate a formal QMS in accordance with the requirements of the current version of ISO 9001 Quality Management Systems, and the following: -

- The principles stated in the current version of ISO 9004 Quality Management Systems – Guidelines for Performance Improvement and BS 7000, Design Management Systems, should also apply.
- Where software is used in the execution of the Services, BS ISO/IEC 90003, - "Guidelines for the application of ISO 9001: to computer software" shall apply.
- The Contractor, as part of its QMS, shall ensure that each of its direct subcontractors establishes and maintains a satisfactory quality assurance and quality control programme specific to the work being performed, and shall submit to Energean for review: -
- Quality Plans for all its direct subcontractors
- Inspection and Test Plans (ITPs) for all direct subcontractors and further direct subcontractors of Key Subcontractors.
- All certification and documentation data must be compiled and maintained on an ongoing basis by the Contractor and must be made accessible and available when requested.

9.1.9.5 Business Processes

The project quality plan (PQP) shall contain a description of the key processes that support service or product delivery, in the following terms: -

- mission and objectives;
- ownership and responsibilities;
- definition covering boundaries, interfaces, inputs and outputs and the natural flow of the process;
- controls surrounding critical activities; and
- performance criteria, on which the process is assessed, including audit and management review.
- The PQP shall contain a description of the mechanisms whereby the requirements of the Agreement and the Contractor's general policies, standards, conditions etc. are communicated to all who participate in the execution of the Services. This description shall also indicate the measures to be established for review of the effectiveness of communication.
- The Contractor shall specify contingency measures for a significant business interruption through some unforeseen event. Emergency procedures to be defined to ensure minimum disruption to the project schedule.

9.1.9.6 Performance Improvement

The Contractor shall have in place structured formalised mechanisms in order to effect continual improvement in overall performance, efficiency and effectiveness of the QMS typically thorough audits, analysis of data and performance on previous contracts (lessons learned) etc. (Reference ISO 9004 Guidelines for Performance Improvement).

Quality Management of Subcontractors

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The Contractor shall ensure, through the application of procedures, that each of its direct subcontractors operates an effective QMS in accordance with the current version of ISO 9001. The Contractor shall maintain records that demonstrate this objective is achieved. The existence of these systems shall not relieve the Contractor of the responsibility for the quality of the Services.

The Contractor's direct subcontracts, and control procedures shall address: -

- The criteria to be used for specifying all quality management standards for a particular part of the work under such Subcontract;
- The criteria to be used for requesting and evaluating subcontractor Quality Plans and quality control plans;
- Provisions for monitoring the compliance of Subcontractors with these contract requirements. Such provisions shall take account of past performance, the consequence of non-compliance of the product or service on the successful performance of the Agreement, the impact on safety and/or the impact on performance for the end user; and
- Provisions for increased supervision where a defective subcontractor's QMS or defective performance has been identified.
- The Contractor shall use reasonable endeavours to ensure that it's direct Subcontract(s) impose an obligation on its direct subcontractor(s) to include in further Subcontracts which may be awarded by the direct subcontractor(s).

9.1.9.7 Audit

The Contractor's QMS shall include planning and executing a programme of internal quality audits, and quality audits in respect of direct subcontractors, and any other Subcontractors where required by the Quality Plan, by formally implementing the principles of: -

- "Guidelines for auditing quality systems" (ISO 10011-1);
- "Qualification criteria for quality systems auditors" (ISO 10011-2); and
- "Management of audit programmes" (ISO 10011-3).

The Contractor shall submit the following after contract award: -

- A proposed project audit schedule to include Contractor audits, direct subcontractors' audits, and audits of any other Subcontractor(s) where required by the Contractor's Quality Plan, for Energean's review and approval (such approval not to be unreasonably withheld or delayed)
- Copies of the last two management review meetings
- Internal audit non-conformance reports (NCR)/corrective action requests (CAR) register for last twelve (12) months.

In addition to the audit requirements for the main contractors and that of their subcontractors, the following facilitation shall be made available: -

- Assessment of the effectiveness of the Contractor's QMS by either:
- Performing quality surveillance, reviews of documentation and/or performing its own quality audits of any part of the Services
- Participating in Contractor quality audits conducted in accordance with agreed project audit schedule. The Contractor will ensure that adequate notification is given to allow participation. (Minimum five (5) Business Days).
- Energean and/or its authorised representatives, shall have access at all reasonable times on prior notice to the facilities, equipment, materials, personnel and records of the Contractor and any Subcontractor(s), strictly for the purpose of auditing their respective QMS(s).
- The Contractor shall cooperate fully with representatives performing such audits and shall ensure that any required corrective actions in respect of non-conformances identified by any quality audit are implemented without delay.
- The results of any audit or surveillance, which has been performed by regulatory bodies having statutory rights of access for the purposes of verifying aspects of the Services, shall be notified within seven (7) Days of receipt by the Contractor.

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- Upon completion of works and services, the Contractor shall carry out a post-implementation audit, supplying a report highlighting those areas where improvements in business performance may be mutually realised in future similar contracts

9.1.9.8 Quality Records

The Contractor shall maintain, and make available, as required during the execution of the Services, records that provide objective evidence that:

- Its QMS and the QMS of its direct subcontractors involved in the Services have been and are effective
- The product and or service complies with the specified requirements.

These records shall include but not be limited to quality records, design calculations, material certificates, supplier data sheets and records, inspection documents required for pre-commissioning and commissioning, non-destructive examination (NDE) reports, site queries, NCR / CAR, as built drawings, manufacturing record books & data etc.

9.1.9.9 Deviations, Waivers and Concessions

- All deviations, waivers and concessions shall be agreed and governed by contract documentation.
- Registers shall be maintained by the Contractor to show the concessions, deviations and waivers granted and implemented.
- The Contractor shall exercise such controls (if any) as specified for Subcontractors in the Contractor's Quality Plan.

9.1.9.10 QA/QC Meetings

Regular meetings shall be held between Energean and the Contractor QA/QC representatives to address and record QA/QC issues as they arise. The frequency and agenda for meetings shall be mutually agreed during the FEED phase, and detailed in the communication management plan.

9.1.9.11 Inspection and Testing

Energean's right of inspection shall apply at any of the Contractor's and Subcontractors' sites. The Contractor shall use reasonable endeavours to ensure that arrangements with Subcontractors make appropriate provision for access on prior notice by Energean authorised personnel or agents.

The Contractor shall use only qualified inspectors to perform factory acceptance tests (FAT) and site acceptance tests (SAT). FATs and SATs on major, critical and essential items of equipment shall be witnessed by specialist personnel of the appropriate discipline holding accountability and full authorisation for acceptance. At least one person attending the testing regime shall fulfil this requirement. At no point shall important milestone tests be performed without this person(s) in attendance.

To supplement the Quality Plan, the Contractor shall prepare and submit an ITP to Energean for review before commencement of each of the construction, installation and commissioning phases of the Services (as appropriate). The ITPs must describe all of the inspections and tests to be performed by the Contractor for the full scope of the Services (as appropriate). The ITPs shall, as a minimum, include activities, acceptance criteria, governing codes, reference procedures together with the Contractor, Energean and Independent Verification Body inspection requirements (i.e. witness/hold points). A pre-production meeting shall be convened at the suppliers premises for all critical components or supplies and the ITPs shall be agreed and approved by all parties during this meeting.

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9.1.9.12 Non-Conformance Report (NCR)

Energean may issue a NCR on any occasion that it becomes aware of the Contractor's failure to comply with the requirements of the Agreement or any aspect of the Contractor's Quality Plan. On receipt of a NCR from Energean, the Contractor must immediately respond by proposing corrective action, and Energean will respond by acknowledging whether the proposed corrective action is acceptable. On satisfactory completion of remedial action, the Contractor and Energean representatives will sign the NCR to confirm that the NCR is no longer in effect.

9.1.9.13 Class, Flag State and Safety Case

The Contractor is responsible for obtaining and maintaining all class and Flag State certification and shall also engage the services of an Independent Verification Body (IVB) to ensure that the requirements of the EU Offshore Safety Directive are addressed and written schemes of examination are produced to confirm that performance standards are implemented for all safety critical elements.

9.1.10 Owners organization

Energean will maintain a small Owner's Organisation throughout the project execution phases. This team is located in a project office in London. The majority of engineering work and most procurement will be executed in northern Europe and the UK represents a convenient central location with good logistic connections to Israel and the Far East. The Energean team is multi-disciplinary managed by an experienced oil-field professional. It has a flat organisation ensuring everyone remains well connected.

As the FPSO moves into fabrication part of the team will re-locate to Asia to control the work managed by TechnipFMC. The team will relocate to Israel in the lead up to installation and start-up works.

A small team can be employed due to the selected contracting strategy as outlined above. With minimal interfaces to manage and strong partnership-relationships developed with key contractors on a win-win foundation a large shadow team is redundant. Large teams by default lead to complex internal relationships and often silo mentalities. The Energean project team avoids this by ensuring staff remain engaged across all elements of the work scope.

The organisation will grow as Operations staff are recruited post FID. At this point the Operations and HSE functions will move to Israel to ensure required management systems are implemented before drilling operations commence. Energean has already acquired office space in Tel Aviv for this purpose.

Detailed organisation charts per phase are attached to the FDP.

9.1.11 Tanin expansion project

The timing of the Tanin development will be driven by a number of factors:

- Evolution of the domestic gas market in Israel and the market share that Energean is capable of capturing,
- Exploration success within the Karish and Tanin Leases and surrounding area.

The current Energean Reference-case requires the existing Tanin discoveries to be on stream 2 years before the Karish Main wells cut water. The Karish Main plateau is estimated to be around 14.5 years long. Hence the Tanin development project will likely commence 2030 with the required infrastructure being complete by end 2033. With this in mind Energean has confidently selected a technology for hydrate inhibition that is not currently fully proven at these water depths, with the view that it will mature within the time scale available.

The scope of the Tanin project is almost entirely associated with the design and installation of new sub-sea infrastructure, including the DEH system, and is therefore different than the Karish phase that is dominated by the development of the FPSO and the dry-gas pipeline. The modifications to the FPSO will be relatively minor,

particularly if the 4th power generator is not needed. 3 wells will likely be drilled to develop Tanin Block A with the development of Tanin Block C and B following later.

The FPSO will be configured to accommodate higher electrical demand and in principal an increase in gas flow rate. This would require the installation of a 4th GTG, whose slot and all necessary equipment provisions have been incorporated into the design of the FPSO. It will be lifted from portside with minimal disruption to ongoing production. This campaign although unusual (brownfield power generation capacity increase), is not unique and is not foreseen to be problematic, provided:

- the design philosophy is rigorously adhered to during the initial phase of the development,
- sufficient time is allowed to properly plan and then schedule the activities.

The installation of the second gas train, driven by an expanding sales market and the identification of additional resources, may coincide with the Tanin development. It will be located on deck M03, close to the production manifold on starboard (see picture below). Energean is currently investigating the benefit of having a crane at this level, to support the specific needs of a phased installation campaign than day-to-day operations. There is extensive empty deck space in modules M04, M09 and M10, sufficient to potentially locate a heavy duty self-installing crane capable of lifting up to 500T making the installation campaigns of future trains much cheaper and flexible than having to mobilise large Heavy Duty Lifting barge.

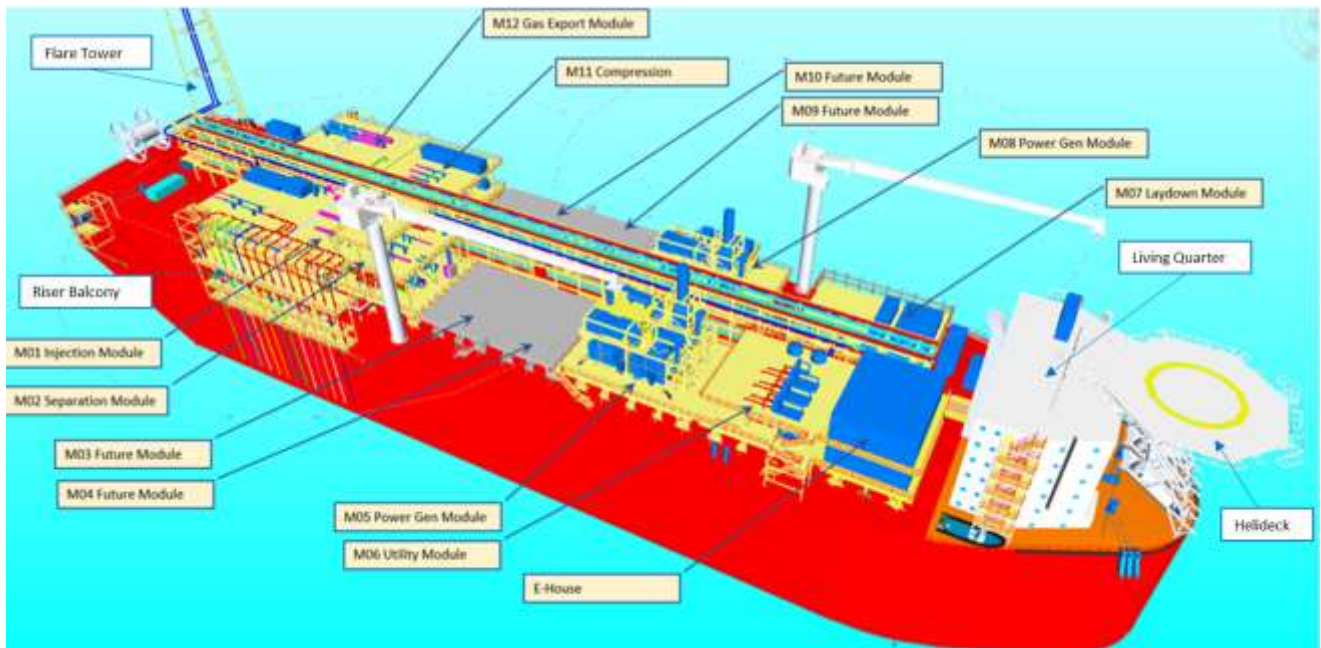


Figure 9-9 FPSO 3D view

9.1.12 Set-up of Energean Israel Operating Company

In parallel with developing the Karish Integrated Production System and laying the groundwork for the later development of Tanin and the exploration of the identified exploration upside, Energean Israel will build an appropriate in-country Operating organisation. Where possible staff that will fill critical roles in this organisation will be recruited during the project execution phase. To this end the future HSE Manager for the Operating Company is already on seat and is acting as HSE Engineer in the early design phases. Similarly the future Operations Manager has also been recruited and is currently working as the project's Operations Engineer. Both these staff are based currently in Energean's London project office.

Attached to the FDP is a detailed document that outlines how the organisation will be developed and matured through each project stage and into Operations.

In Israel a Permits and Approvals Engineer has joined Energean and it is envisaged that post start-up he will move into the companies Engineering Manager position responsible for the future build out of the assets.

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A detailed organisation structure has been prepared for each phase of the development and this will be used by HR staff to make sure the right people are hired at the right time and located in the correct locations. This spans the entire project duration including the Operations phase.

Energean's in-country Operating Company will be based upon a structured management system embracing Good International Oil Practices. The companies HSE and Operations management systems are currently being developed building on Energean's operating experience in Greece where it operate complex, sour pre-salt oil developments.

9.1.13 Field Abandonment Planning

9.1.13.1 Well Abandonment

As part of the field abandonment plan, details will be provided later in field life regarding the final abandonment of the wells. However, during the detailed well design phase consideration will be given to ensuring the final well abandonments can be as simple and cost effective as possible. The figure below shows a conceptual well abandonment design. It is anticipated that wells would take approximately 30 days to abandon at a day rate of US\$ 340,000 hence an abandonment cost per well of US\$ 10.2 mln.

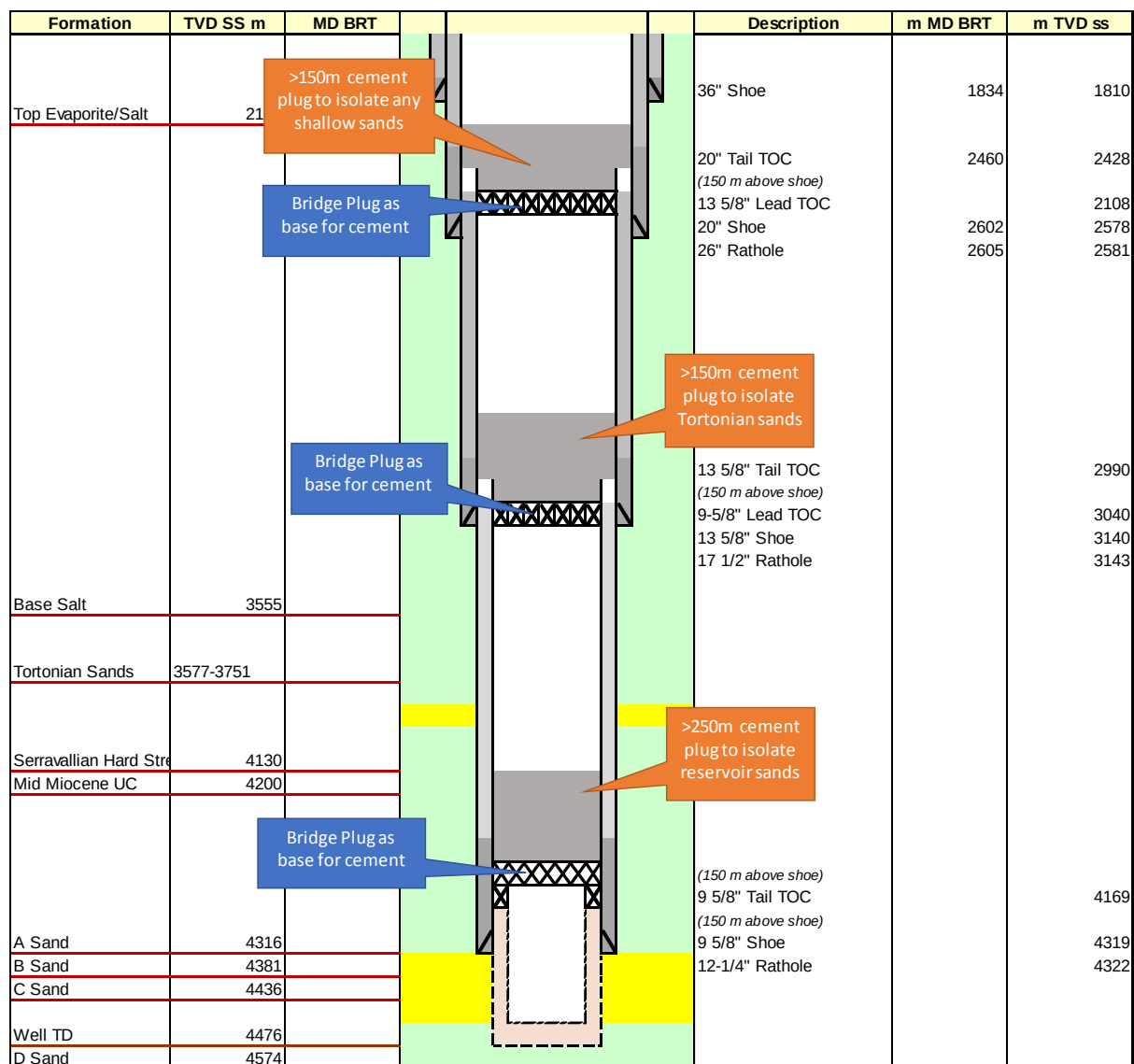


Figure 9-10 Well abandonment scheme

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9.1.13.2 FPSO abandonment

The boat will be remobilised or scrapped. Nothing will remain in Israel. The mooring lines will be retrieved and the suction cans (14) will be left in-situ.

9.1.13.3 SPS/SURF

All systems will be purged of HC's, cleaned from any debris related to production and flooded with sea water.

- Karish manifold and short spools will be removed.
- Only the manifold suction can (1) will be kept in place
- All risers & RBS & PLET's & SSIV structures will be removed including the mud mats if easily retrieved.
- All long flowlines (KN01 line), export pipeline are proposed to be kept in situ flooded. They represent no harm to the environment and would be a prohibitive cost to retrieve such an asset.

The umbilicals and any auxiliaries will be removed.

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10 Operations and Maintenance

10.1 Operations Philosophy

Energean aims to be the premier operator in the Eastern Mediterranean region developing a highly competent proactive workforce, maximizing uptime, being the most cost efficient operator that will meet or exceed the Israel government's expectations without jeopardizing our values or integrity.

To achieve the above, Energean is committed to:

- Maintaining cost effective operations
- Maximizing reliability & availability, exceeding industry benchmarks with safety and integrity.
- Ensuring the integrity of all aspects of our processes and systems.
- Safety and environmental protection will be the core value of our business.
- Actively developing empowered people to achieve business goals.
- Deploy a robust Operating Management System, (OMS), to manage quality management of the business through Continuous improvement.

10.2 Operations organization

The Operations organization to support the start-up and ongoing operations of the Karish and Tanin development will follow a traditional offshore floating installation Operations & Maintenance, (O & M), set up. An experienced Operations Manager will lead the overall O & M team in all aspects of activities regarding the day to day and longer term operations and maintenance of the development.

The offshore team will be an integrated team specifically focused on production and maintenance operations. Led by an experienced Offshore Installation manager, there will be a production team lead and a maintenance team lead who will exercise the day to day safe production and maintenance activities of the FPSO, subsea systems, wells and export pipeline.

The Marine operations will be sub contracted to a suitable and competent Marine operations company who has experience of operating in the Eastern Mediterranean and will come under the direct ownership of the Energean Operations manager.

All Logistics for the development will be contracted out to a suitable experienced Israeli 3rd party company who has the necessary experience and capability to operate safely within the region to international standards. Energean will set up and manage the overall logistics activities through an experienced staff Logistics manager who will report directly to the Operations manager and be onshore based.

10.2.1 Development phase, including drilling

Throughout the development phase of the project the O & M team will be assembled through a steady and consistent recruitment campaign matched to the increasing demands for O & M input into the execution activities of the project. The initial recruitment will focus on the leadership roles required to set up and establish a suitable O & M team for a new country set up. Key roles will include; Logistics manager, Offshore Installation Manager, (OIM), Maintenance manager. All key roles will be direct reports of the Operations manager for the project.

Through the Logistics manager role an early Logistics organization will be established to support drilling operations. This will also include early contracting with a local logistics company to support drilling operations and building the necessary plans to ultimately support the FPSO, wells, subsea infrastructure & pipelines.

The OIM position will be responsible for developing the offshore O & M organisation in accordance with the manpower plan forecast to support factory acceptance testing of new equipment and topside integration of the FPSO Hull and process systems. The offshore O & M team will also set about developing the processes, systems and procedures necessary for the operational phase of the project. The offshore O & M team will be

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co-located in the shipyard when the topside integration activities take place. This will give the newly formed team invaluable experience and intimate working knowledge of systems and equipment during the integration and sail away phase of the project. It will also be well placed to support the EPC contractor during early commissioning activities.

The maintenance manager role during the development phase will be responsible for the overall maintenance build for the facilities. This will include working closely with the EPC contractor to ensure that all systems and equipment are registered within a Computerised Maintenance Management System, (CMMS), Maintenance procedures and schedules are developed for all facility equipment and that a full spares inventory is established through the EPC contractor prior to production commissioning and start up. This role will also be responsible for the recruitment and training of the Maintenance team.

During the development phase there will be considerable effort placed on recruiting and training where possible, local Israeli nationals to take on core O & M roles both onshore and offshore; however, it is anticipated that a significant part of the team will be recruited internationally to ensure the O & M team has sufficient skills and competency to take over operations after the initial commissioning phase from the EPC contractor.

10.2.2 Operational phase

The O & M team will have been fully recruited during the development phase and will have gone through a rigorous training and competency program ahead of commissioning and start-up of the facilities.

During the operational phase the O & M team will continue to be actively managed to ensure competency across all core roles is maintained. Over time the O & M team will transition to be manned largely by Israeli nationals. The speed of this transition will be competency based to ensure that the facilities maintain a competent workforce both onshore and offshore at all times and comply with safe and compliant operations.

10.2.3 Competence Assessment and Assurance

Throughout the development phase recruitment of O&M staff will be ongoing to achieve the correct manning requirements ahead of start-up of operations. All positions within the O&M team will have a job description and competency profile assigned.

Various methods of international assessment practise will be employed to initially select suitable staff during the recruitment phase and then to ensure competency levels are in place prior to start up and ongoing production operations. Internationally recognised standards for oil & gas competency will be utilised e.g. OPITO, (Offshore Petroleum Industry Training Organization). Experienced staff will be trained to become qualified Assessors and Verifiers of competency for staff within their technical discipline.

With the support of the HR function the Energean O & M team will deploy and manage the competency of all O & M staff through a competency framework tool kit. Competency & Training records of all staff will be maintained within a managed database which will be audited on a regular basis by the Operations manager to ensure quality and assurance that the facilities at all levels are staffed by competent staff.

10.2.4 Control room dynamic simulator

During the execute phase of the project a contract will be placed with the vendor supplying the integrated control system for the facilities to deliver alongside the main control systems a fully functioning dynamic control room simulator. This simulator will be utilized during the final stages of the execute phase to training control room operators on the facilities specific operations of the Karish and Tanin development. This will lead to a formal assessment of competence ahead of start-up of the facilities.

This approach will add assurance that the facilities will be started up and operated by competent control room personnel. A secondary function of the simulator will be to enable the process engineering staff to simulate plant conditions for the purposes of modifying or enhancing production operations systems ahead of deploying

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them on the live facilities, therefore reducing risks and managing any changes to the original engineering design.

10.3 Manning levels

As per section 10.2, O & M manning levels will be developed during the development phase for both onshore and offshore teams. Recruitment of all core team roles will take place through the execute phase of the project. The project is currently looking to have approximately 70 personnel offshore and 25 support personnel located onshore during normal operations. The actual numbers of staff will be refined further during the project FEED phase. These numbers do not include staff supporting operations within 3rd party Marine and Logistics contracts.

It is anticipated that the offshore team will work an equal time rotation and therefore the numbers of staff per position will be double the core team to take in to account the personal leave cycle required.

10.4 Production Monitoring and Reporting Plan

Production monitoring and reporting plans will be drawn up during the project execute phase in accordance with company, customer, regulatory and fiscal requirements.

10.5 Facility Maintenance and Inspection Strategy

Maintenance and inspection will be carried out in accordance with the latest industry practices regarding Reliability Centred Maintenance, (RCM), linked to a Computerized Maintenance Management System, (CMMS). Risk Based Inspection, (RBI), programs will be utilized to monitor and manage integrity of vessels and pipework across the full facilities, inclusive of subsea, pipelines and topside.

10.5.1 Sub-sea systems including X-mas trees

Subsea systems and X-mas tree maintenance and inspection programs will be set up in accordance with industry guidelines and manufacturer recommendations. Once final selection of this equipment and supplier are confirmed then the maintenance and inspections schedules will be up loaded into the Computer Maintenance Management System, (CMMS).

10.5.2 FPSO

A full maintenance and inspection program will be set up in accordance with industry guidelines and manufacturer recommendations. Once final selection of equipment and suppliers are confirmed. The maintenance and inspections schedules will be up and loaded into the Computer Maintenance Management System, (CMMS).

10.5.3 Pipelines

Pipeline maintenance and inspection programs will be set up in accordance with industry guidelines and manufacturer recommendations. Once final selection of this equipment and suppliers are confirmed then the maintenance and inspections schedules will be up loaded into the Computer Maintenance Management System, (CMMS).

10.5.4 Onshore systems

Onshore systems maintenance and inspection programs will be set up in accordance with industry guidelines and manufacturer recommendations. Once final selection of this equipment and suppliers are confirmed then the maintenance and inspections schedules will be up loaded into the Computer Maintenance Management System, (CMMS).

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10.5.5 Maintenance Turnarounds

Maintenance Turnarounds will be scheduled based on industry and regulatory recommendations as well as manufacturer guidelines for equipment which cannot be maintained and inspected during normal hydrocarbon processing activities. It is anticipated that Risk Based Inspections and the output from its analysis will drive the final decisions on when major Turnarounds are planned and scheduled.

10.6 Logistic Operations

At this early stage of the project it is anticipated that the O & M team will own the Logistics function for the project from initial set up during the execute phase through into normal production operations. This will also include drilling operations which are expected to commence ahead of major logistical support for production operations.

The port city of Haifa would be a likely location for the Logistics base to be set up, however further evaluation of options and support service companies with take place during FEED and early execute phases of the project to clarify and confirm this position.

10.6.1 Land

A suitable Logistics land base will be set up along with freight forwarding and supply chain support requirements. This may be in Haifa once further evaluation has taken place.

10.6.2 Marine

A suitable Marine logistics base and set up will be put in place during project execution to fully support the needs offshore. This may be in Haifa once further evaluation has taken place.

10.6.3 Air

A suitable air base and air support company will be sourced that offers all needs to maintain supply and support of offshore operations. Energean is aware of options in and around the location of Haifa, more work will be completed to evaluate options during the FEED and execute phase of the project to ensure a suitable contract can be placed that will support ongoing operations and all emergency requirements.

10.7 Well work-overs and recompletions

It is expected that after ten to fifteen years of production the Karish C/D production wells will be re-entered and the upper completion recovered through the horizontal Xmas trees. This activity will take place when all three Karish wells have reached a water rate above 10 bbls/mmscf or the total water production rate exceeds 3,000 bwpd. The wells will be converted to B Sand producers as described in section 7. It is expected that this will take ~ 40 days per well at \$450,000 / day (inclusive of rig rate and spread rate) resulting in \$18,000,000 per well workover cost.

11 Health, Safety, Environment and Security

11.1 Energean Israel HSES Management System development

Energean Israel intends to apply its Corporate HSES Management System which will be enhanced to cover operations in deep water offshore Israel. The Energean Israel HSES Management System will be defined in the HSES System Management Manual and associated documentation that will be developed and issued Q3 2017. The HSES Management System shall comply with the Israeli (Labour Inspection (Organization) Regulations (Safety Management Plan), 5772-2012 and will be in accordance with OHSAS 18001.

11.1.1 Hazard and Effects Management

The design and operation of the Energean Karish and Tanin facilities will be carried out using the Hazards and Effects Management Process (HEMP). HEMP provides a structured approach to managing the hazards and potential effects of Energean's activities and is summarised in the flowchart below:



Figure 11-1 Principles of HEMP

There are numerous techniques that support the HEMP process, such as Hazard Identification (HAZID), Hazards Analysis (HAZAN), Hazards & Operability Study (HAZOP), Task Risk Assessment (TRA), Quantitative Risk Assessment (QRA), Job Safety Plan (JSP), etc. Further details of such processes are provided in Section 10.2.1. The outcome of the HEMP process is generally recorded on Bowtie diagrams, which provide an extremely powerful tool for depicting the complex relationship between hazards, threats, consequences, control barriers and recovery measures identified as being relevant for a specific Major Accident Hazard.

11.1.2 European Offshore Safety Directive

As a European Company, Energean intends to comply with the requirements of the European Directive on Safety of Offshore Oil & Gas Operations (2013/30/EU), which sets out the requirements for the management of Major Hazards.

11.1.3 Report on Major Hazards (HSE Case) development

Energean will develop a Report on Major Hazards (Operations Safety Case), which will comply with the requirement of the European Safety Directive. In summary, the Report on Major Hazards will contain the following sections:

- Description of the Installation, including all key production, utilities and safeguarding systems
- Summary of the HSES Management System for the Installation, including Emergency Response arrangements
- Description of Major Accident Hazards and the Hazard Register
- Details of Safety and Environmental Critical Elements, Performance Standards and arrangements for Independent Verification

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- Demonstration that risks have been reduced to As Low As Reasonably Practicable (ALARP)
- Details of any Remedial Action Plan

The Report on Major Hazards will be produced for the Offshore Facilities, Gas Export Pipeline and Onshore Facilities and will provide a systematic, documented review of all Major Accident Events and associated prevention, control, mitigation, escape and rescue and recovery measures.

11.2 Safety Plans

The Karish Tanin Development Project have issued an HSE Plan which details specific HSE related activities, responsible parties and proposed timing of all planned HSE related activities required to comply with Israeli requirements and Energean HSES MS. The HSE Plan will be reviewed and updated annually.

Energean also intend to develop the following plans:

- Environmental Management Plan both on and offshore
- Environmental Monitoring Plan both on and offshore
- Waste Management Plan
- Oil Spill Contingency Plan
- Emergency Response Plan

11.2.1 Safety in Design

The Karish Tanin FPSO and associated subsea and Landfall Facilities shall be designed in accordance with appropriate International Codes and Standards and safety in design will be enhanced through the application of the following HEMP techniques.

11.2.1.1 HAZID and HAZOP

The design of the Karish Tanin facilities will be subject to Hazard Identification (HAZID) Study and Hazard and Operability (HAZOP) Study. HAZID Study normally applies when trying to identify the range of hazards i.e. fires, explosions, dropped objects, collisions and impacts etc. associated with the design and layout of facilities. HAZOP Study is a systematic methodology that has been developed specifically for the identification of process hazards and involves assessment and review of the Piping and Instrumentation Diagrams (P&ID's).

11.2.1.2 Safety and Environmental Critical Elements

A full set of Safety and Environmental Critical Elements (SECE's) shall be developed covering the systems and facilities involved with the prevention, detection, control, mitigation and escape/recovery from the Major Accident Events (MAE) identified at the HAZID.

A comprehensive set of SECE Performance Standard (PS) will be developed, which are further explained in the section below.

11.2.1.3 Performance Standards

For each identified SECE in Section 10.1.2.1 above, a comprehensive set of performance standards shall be developed. Performance Standards will include the following requirements:

- Functionality - discrete and verifiable functional requirements
- Availability - required availability or probability of failure on demand
- Survivability - any requirement to survive credible blast loads or jet fire loads

The agreed SECE performance standards will form the basis on the Facilities Written Scheme of Verification.

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11.2.1.4 Quantified Risk Assessment (QRA)

During Front End Engineering Design (FEED) Quantified Risk Assessment shall be undertaken to demonstrate that project target risk levels are achieved in terms of Individual Risk Per Annum (IRPA), to identify the risk reduction potential associated with identified risk reduction options and to assist with demonstration that risks have been reduced to As Low As Reasonably Practicable (ALARP).

11.2.1.5 ALARP Demonstration

An important aspect regarding the design of manned production facilities is demonstration that the risks posed to personnel, the environment and the asset have been reduced to ALARP and that the costs associated with implementation any further risk reduction measures are disproportionately high when compared with the level of risk reduction achieved. As a general principle Energean shall apply International and Industry Standards and will implement low cost risk reduction measures. Energean will use QRA and Cost Benefit Analysis (CBA) to assess the cost of implementation and the extent of risk reduction benefit possible with implementation of a specific risk reduction measure. This process will contribute to the ALARP Demonstration Report.

11.2.1.6 Well Delivery Process

The Lloyds Register (LR) Well Delivery Process (WDP) will be followed for the planning and execution of the wells. The LR WDP forms part of the LR Integrated Management System (LRIMS) which contains a comprehensive set of standards and procedures for the execution of well construction projects.

The purpose of the WDP is to ensure that the following high level steps are implemented:

- Structured risk and hazard identification processes.
- Internal review and sign-off of design documentation (all process steps).
- Review and sign-off of design documentation by the Project Manager and/or Superintendent (conceptual, functional, detailed design steps).
- Peer review of well design and programs.
- Independent verification of well design & planning documentation.
- Quality Assurance and Quality Control of critical well equipment
- Rig intake procedure to ensure both the drilling contractor's quality systems and the safety & environmentally critical equipment is fit for purpose.
- Robust management of change procedures.

11.2.1.7 Drilling & Completion Standards

The wells will be planned and constructed in accordance with LR standards which are designed to meet or exceed relevant ISO and API standards. As part of the WDP, once the MODU is identified a review of LR standards against those held by the rig contractor will be conducted. Any differences will be resolved with the conclusions documented in a project bridging document. Also, the project will be audited to confirm:

- Adherence to LR Integrated Management System (LRIMS)
- Adherence to ISO standards
- Adherence to project internal procedures
- Regulatory compliance
- Compliance to contractual or client requirements
- Adequacy of arrangements in place to control work

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11.3 Operational Safety

Energean operational activities shall be covered by Safe Operating Procedures. Standing Instructions, will be used as a minimum for temporary or non-routine operations. The risk associated with all operational activities shall be assessed and documented. An Integrated Safe System Of Work (ISSOW) shall be employed for all non-routine work.

11.4 Environmental Impact Assessment

The requirements for the Karish Tanin Environmental Impact Assessment are presented in this section.

11.4.1 Scoping level assessment

Energean have carried out an Environmental Impact Scoping Report for the identification and consideration of the key environmental and social impacts which could arise from the Project and which will form the scope of the Environmental and Social Impact Assessment (ESIA).

The ESIA scoping takes into account the assessment standards for the Project, which include local requirements when available, and relevant international guidance (i.e. IFC/World Bank).

The scoping process also facilitates the ‘scoping out’ of any aspects that are not likely to result in significant adverse environmental impacts, and therefore do not require consideration in the ESIA. The completed assessment process will be reported in the ESIA Report.

It should be noted that the ESIA Scoping Report will also meet the requirements of an Environmental Impact Statement (EIS) per Israel's *Planning & Building Regulations (Environmental Impact Statements) 5763-2003*.

11.4.2 Environmental Base Line assessment

An Environmental Baseline Survey (EBS) will be undertaken during Q3 2017 in accordance with “Guidelines for Monitoring the Marine Environment due to Petroleum and Natural Gas Operations and Production Activities in Israel” and as advised by the Ministry of Environmental Protection (MOEP) and the Ministry of National Infrastructure, Energy and Water Resources (MNIEWR). The EBS will provide reference data reflecting the state of the environmental condition prior to drilling activities and installation of an FPSO, Gas Export Pipeline and associated facilities.

11.4.3 Full EIA development

A fully developed, project wide Environmental Impact Assessment (EIA) will be developed by Energean and issued prior to Final Investment Decision (FID), as this will be required by major international banks and Finance Houses. The EIA will summarise the assessment of potential impacts on the environment and state what actions are required to be taken to manage and mitigate identified environmental impacts.

11.4.4 Environmental Management Plan EMP

An Environmental Management Plan will be developed which will include, but not be limited to those actions and commitments identified in the EIA for the Karish Tanin Development. The EMP will include the requirement for follow-up post drilling environmental monitoring and subsequent environmental monitoring during the production operations phase.

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11.5 Security provisions

11.5.1 General

The Karish and Tanin field's offshore location and the near-fields production facilities in the form of a Floating, Production, Storage and Offloading vessel (FPSO) requires distinctive security arrangements, regulated by the Navy, and which holds the overall defence responsibility for the coastal areas.

The Security on the FPSO, its close proximity, the security of the service crafts related to the development and operations of the fields, as well as related onshore infrastructure and facilities, is the responsibility of the company, which shall be in accordance with Navy guidelines.

The FPSO design will take into consideration security installations requirements in terms of structure, systems (engineering systems and designated systems), procedures and operations.

The FPSO will have a dedicated on-board security force with active and passive defence capabilities in line with Navy instructions.

11.5.2 Scope and Purpose

The purpose of this document is to provide a high level overview of design requirements to meet the specific regional security requirements for the pre-FID stage. At this stage, no details are provided, as these will be explored further in the FEED stage and incorporated in an updated Design Basis. This section development is based upon input through Energean Israel's security advisor. Security is a function of the design, build, operation requirements and organisation. No details will be provided for operational requirements at this early stage, but it will be evaluated further in the FEED phase in close cooperation with Israeli Security.

11.5.3 International Ship & Port Security (ISPS)

Although there is no SOLAS Chapter XI-2 and ISPS compliance requirement for mobile offshore units, except for transit voyages, a shipboard security plan shall nonetheless be established in accordance with the International Ship and Port Security (ISPS) code, but due to the specific regional security risk, the expectation is that the security requirements for the FPSO will extend well beyond the normal ISPS requirements. The Interface between field specific security requirements and the ISPS will be explored and developed during FEED.

11.5.4 Design/layout requirements

11.5.4.1 General

The following sections provide a high level description of specific security design requirements, with further details and specifications to be established during the FEED phase. It is recognised that security design requirements will have an impact on the scope, which is why it is paramount that they are designed into the overall FPSO design to help avoid major changes.

11.5.4.2 Layout – Living Quarter

11.5.4.2.1 Security team Cabins

The size and composition of the security team shall be finalised in FEED, but the capacity currently allows for a 15-person security team.

11.5.4.2.2 Security Coordination Centre

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A Security Coordination Room shall be provided in the living quarter. Presently this is planned to be on the upper most deck to allow easy outside access to the security and mast and other FPSO vantage points. This room will be continuously manned by dedicated security staff and provided with necessary communication and control equipment in compliance with the final design and operational security requirements.

An area of 130 m² has been set aside to accommodate the Security Coordination Centre, and required storage. It is anticipated that the Security Coordination Centre shall be located in close proximity of the CCR, which shall likely be on the same deck.

11.5.4.2.3 Storage requirements

Storage space shall be provided, including secure lockers for security staff equipment. This will form part of the security coordination centre, with alternative spaces available in the machinery rooms' empty areas. Detailed design of this storage, including any special requirements for reinforcement of bulkheads/doors will be further developed during FEED.

11.5.4.2.4 Shelter/Safe Haven

The living quarter shall provide for a safe haven, where the crew can be gathered and kept safe in the event of a security threat. Details for the arrangement of this, including necessary reinforcements will be further developed during FEED. Opportunities for combining this with the regular Temporary Refuge, including command and control functions will also be further investigated during FEED.

11.5.4.2.5 Security Mast (Crow's nest)

The security mast shall provide space for a dedicated wide-band security radar to provide surveillance of the FPSO exclusion zone as well as necessary antennas/satellite domes for the security communication equipment. Type and dimensions will be specified during FEED, including mechanical handling.

11.5.5 Layout – Utility and Process areas

There will be a requirement for storage facilities on the FPSO for additional equipment for the security team, not including the LQ which is covered under the living quarter. This will include a variety of Marine Equipment, including diving equipment, for the security staff to use in conjunction with FRC operations. Storage in the immediate vicinity of the FRC embarkation stations may need to be considered during FEED. Co-location with standard FRC crew equipment may be possible.

11.5.6 Medical Equipment

Additional medical equipment requirements, including for emergency medical support, i.e. dedicated stretchers for helicopter extraction, will be explored during FEED. Potential for synergies with provision of more standard safety, first aid and medical equipment for use on the FPSO shall be investigated.

11.5.7 Security Observation Posts

Provision of areas for security observation posts has been made, with the design to be confirmed during FEED. Location of the observation posts will be evaluated during FEED, taking account of access, hazardous area classification while ensuring that the observation posts collectively provide visual observation coverage of the entire perimeter of the FPSO

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11.5.8 Marine Equipment

11.5.8.1 Fast Rescue Craft

The security team shall have access to a Fast Rescue Craft (FRC), which shall be specified by the security advisors during FEED. To avoid conflict with regular Search and Rescue (SAR) operations, there is an opportunity for the security team to perform the SAR role. However, potential for optimisation shall be investigated during FEED. The FRC shall be davit launched, with retrieval through both the davits as well as the FPSO cranes and offshore support vessel cranes. Type, size and other specifications for the FRC will be detailed during FEED.

11.5.8.2 Observation, Communication and Control Systems

11.5.8.2.1 Radar Equipment

Dedicated wide band radar equipment for security monitoring of the exclusion zone will be required. Details, including dimensions and control systems for this equipment shall be further defined during FEED.

11.5.8.2.2 Optical surveillance equipment

Suitable vantage points for electro-optical equipment with day and night vision capability shall be provided, enabling 360 degree monitoring around the FPSO.

11.5.8.2.3 Telecommunication

Dedicated communication equipment for security purposes will be required. Communication equipment will include, but not necessarily be limited to: -

- Satellite Communication
- UHF/VHF radio
- Portable communication equipment

Hazardous area zoning and ATEX compliance requirements shall be taken into account.

11.5.8.2.4 Long Range Acoustic Device

A long range acoustic device (LRAD) for direct acoustic communication across long distances may be required on board. Further details to be provided during FEED.

11.5.8.2.5 Remote Operated Vehicle (ROV)

Use of an ROV will be required for underwater hull security inspection. It is envisaged that this ROV shall also be utilised for marine inspections. Details shall be defined during FEED phase.

11.5.8.3 Illumination

In addition to the general area illumination on the FPSO, including lights and searchlights as mandated statutory and regulatory requirements, it is envisaged there will be a number of security related illumination requirements, which shall be detailed during FEED phase, i.e., Perimeter floodlights and search lights (Consideration needs to be given to hazardous area classification and ATEX compliance), details to be defined during FEED phase.

Specific arrangements to maintain ATEX compliance and ignition source control shall be further considered if there is a need to place these in hazardous areas.

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11.5.8.3.1 Illumination Control System

It is envisaged there will be a requirement for an Illumination Control System. The principle of this is to enable 'Darkened ship' condition of increasing magnitude up to and including extinguishing all light sources on the FPSO. There are obvious details regarding the control logic that needs to be worked out in detail during FEED. Consideration needs to be given to both mandatory navigation lights as well as emergency lights governed by the emergency power supply and safe operating philosophy.

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12 Local Content development

In accordance with the Lease, Energean Israel will submit to the Commissioner a detailed plan, including modes of operation, objectives, timetables and milestones, for the employment of Israeli employees, in which the Lease Holder will detail the measures intended to be taken for the employment of the Israeli professional staff and employees in the development, installation and operating works of the Karish Field and Tanin Field Production System. The objectives of the plan will include an annual scope increase, starting from the grant year of the Lease, of employment of Israelis, both the professional staff in the oil and gas industry and of other employees. The plan will set forth, to the extent possible, numerical indices for increasing the percentage of the Israeli professionals, including the employees occupying senior positions, from the total number of all the professional employees, to be engaged in the above operations during the entire term of the Lease operation.

The plan will include training the Israeli employees to perform such development and construction works and operation of the Karish Field and Tanin Field Production System. The training plan will include, to the extent possible and as required, the variety of disciplines necessary for performing such operations, including in the fields of engineering, earth and environmental sciences as well as the numerical targets for such training. For this purpose, the term "Israelis" - means individuals who are citizens and residents of Israel.

Energean Israel will submit to the Commissioner a detailed plan, including modes of operation, objectives, timetables and milestones, for industrial cooperation, purchasing products manufactured in Israel, purchasing know-how and services from Israeli entities and providing subcontracting works to Israeli entities. The plan's objectives will be, *inter alia*, to increase, to the extent possible, annually, commencing from the year the Lease was granted, the value of the Israeli component in the expenses for development of the field and operating the Production System. For this purpose, "Israeli Entities" - individuals who are citizens and residents of Israel, corporations that were duly incorporated in Israel, and whose centre of activity is in Israel.

The plans will be submitted to the Commissioner no later than October 2017. Upon submitting the application for the Operating Permit as set forth in section 22 in the Lease, the plan will be updated. Plan concerning the first 5 years of the production period and thereafter, updated plans every 5 additional years up until the completion of production from the Karish and Tanin Fields.

In the framework of the plans set forth in Section 30.1 in the Lease, Energean Israel will advertise, insofar as possible and reasonable under the circumstances, advertisements on the search for employees and the skills required, in Hebrew as well. In the framework of the plans set forth in Section 30.3 in the Lease, Energean Israel will identify and examine the Israeli suppliers, Israeli technology companies, laboratories and research institutions in Israel. Energean Israel will perform, insofar as possible and reasonable in the circumstances, impartial processes for the purchase of products and services which will allow full and fair participation of Israeli entities, and will treat the Israeli entities satisfying the requirements with equality and on a competitive basis.

The entire investment in local content will not be less than the accumulated amount of US\$ 80 million over 8 years, commencing on the Lease Amendment Date.

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12.1 Operations phase local content

The Operations and Maintenance of the Karish Tanin development will need to be in place throughout the production phase of the development which is estimated to be 30 years.

Due to the long term nature of the Operations and Maintenance function it offers some of the best opportunities for Energean to develop and sustain local content from people capability through to use of local 3rd party support activities.

Energean expect to harness a significant portion of its operational supply base needs from local suppliers. This will cover a wide spectrum of Logistical needs as well as supply of materials to support offshore operations and maintenance. Where this is not possible Energean will look to support and nurture the local supply chain such that it can reduce local supply gaps over the course of the field life of Karish & Tanin.

It will be Energean's intent where possible to recruit suitably qualified and experienced staff into all roles within the Operations & Maintenance organization. When this is not possible, Energean will develop Israeli capability for future succession to displace expatriates brought in to deliver the Karish Tanin development into operations.

Energean will achieve this by building in an aggressive recruitment process that will seek to recruit Israeli nationals from technical Colleges, Universities & from within the Petrochemical industry who have transferrable skills. Energean will look to build strong relations with tertiary education centres in Israel who have programs which link well to the core jobs within the Operations and Maintenance organization.

Utilizing the predefined Competency framework for Operations and Maintenance staff, Energean will utilize this framework to develop staff and give them a career path which can meet the needs of the Operations and Maintenance organization and the wider Israeli offshore oil and gas market.

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13 Risk Assessment and Management

13.1 Risk Assessment

Energean Israel employs a comprehensive risk management system to ensure that it executes the Karish and Tanin development project in an effective manner. Risk Matrices for each technical discipline – Drilling, Sub-surface, Facilities engineering and Operations – have been prepared. Risk are classified by Likelihood and Consequence and mitigation plans developed. Risk owners for all risks judged critical are appointed. Risk registers are regularly reviewed and formally updated at the start of each project phase.

An overall Energean Israel risk matrix has also been developed that spans the full TECOP – Technical, Economic, Commercial, Organization and Political – spectrum. This is managed in a similar way to the more detailed technical registers. The critical Technical risks are repeated in the TECOP register. The Energean Israel Board reviews the TECOP register monthly with particular focus on key mitigation measures.

Risk matrices for the project and venture are attached to the FDP.

13.2 Risk Management

The objectives of Risk and Opportunity Management are to ensure: -

- Quality of our decision making and planning
- Learning from and resilience to changing events, incidents and crises
- Effective identification, evaluation and analysis of uncertainty
- Effective identification, evaluation and driving of opportunities
- Compliance, stakeholder confidence and trust
- Increased likelihood of achieving our business objectives
- Our people and our assets are safeguarded and protected

At regular intervals the project will assess the risks to Energean's business and report them, along with suggested mitigating measures (whether in place or not) on the Risk Register. The Risk Review process will provide a common view of the risks to the business and how these risks are being managed / mitigated. The risks and suggested mitigating measures will be periodically reviewed, at appropriate levels of management (including update to the Steering Committee). Agreed actions will then be implemented and may include revisions to internal management systems (where appropriate). Implementation of the actions will be tracked with appropriate management reporting.

13.2.1 Management of Change (MoC)

Project Management of Change procedure (to be agreed between Energean and the Contactor) defines the process to be undertaken to ensure that change, when/if it occurs, is appropriately evaluated and managed. This procedure provides a framework for the management of all proposed change requests within the Karish & Tanin Project and between project contractors, subcontractors and suppliers.

A formal MOC form shall be raised for all changes to the following: -

- Changes to the Basis of Design, Functional Specification or agreed Scope of Work.
- Changes to the Project Schedule.
- Changes to the Project Budget.
- An MOC form may also be raised for other major changes on the project, such as a change in key personnel, Drill centre locations, etc.
- The roles and responsibilities required to ensure the MOC process runs smoothly and efficiently are documented within the Project Management of Change Procedure.

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13.2.2 Scope Change Control

The need to control change and the limitation of the consequent impacts is recognized as an essential part of the work. A systematic approach to management of change will therefore be implemented throughout all phases of the contract.

13.2.3 Contractor Change Management

The Contractor's Change Management System shall identify, review, approve where appropriate and provide demonstrable implementation of any changes. Energean shall be involved in the management of significant changes over agreed.

13.2.4 Design Change Control

The Contractor's Design Change Control Procedure, will be applied to control engineering changes with respect to the engineering performed in the proposal phase and with respect to engineering issue status IFC or higher. The procedure shall become in force immediately upon project start. Lead Engineers shall prepare a Design Change Form (DCF) to capture the following: -

- Changes to the contract design basis
- Changes to documents at IFC status and above
- Changes to engineering scope

Any changes will require the approval of the Contractor's Engineering Manager or the relevant Sub- Works PM, before a design change can be issued for approval to Energean. Additional approval from the Contractor's Project Manager is required in the following situations: -

- Any cost impact to PMO
- Any impact on the project schedule

All DCF's are to be logged, including those that are rejected, in the DCF register.

Further to the Design Change Control procedure, a Design Change Close-out Procedure will be implemented on the project to verify that approved design changes have been incorporated into the design and into the procured equipment and materials and into the fabrication works, where applicable. The Contractor shall prepare the Design Change Close-out Form (DCOF) upon approval of the DCF.

The Contractor's Engineering Manager shall be responsible to confirm with all relevant parties the implementation of the DCF. Proof of implementation shall be via formal issues of documents, formal issues of Purchase Orders or Purchase Order Amendments and via as-built reviews.

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14 Attachments

The following documentation is attached as specified in the Israeli guidelines for preparation of Field Development Plans. Attachments are provided in paper form (2 copies) and as electronic files. They are arranged – where applicable – in folders corresponding to the main sections of the current FDP.

Section	Attachment	Title	Number if applicable
1 Management Summary			
2 Subsurface Geological and Geophysical evaluation			
	Attachment 2:1	Karish Complex, Top C Sand Depth Map (m)	
	Attachment 2:2	Karish Lease, Top A Sand Depth Map (m)	
	Attachment 2:3	Karish Lease, Top A Sand Depth Map (m) w/ scour intensity	
	Attachment 2:4	Karish Lease, Top B Sand Depth Map (m)	
	Attachment 2:5	Karish Lease, Top C Sand Depth Map (m)	
	Attachment 2:6	Karish Lease, Top D Sand Depth Map (m)	
	Attachment 2:7	Tanin Lease, Top A Sand Depth Map (m)	
	Attachment 2:8	Karish-1, VSP Acquisition and Processing Reports	
	Attachment 2:9	Tanin-1, VSP Acquisition and Processing Reports	
	Attachment 2:10	EMED-10 Processing Report	
	Attachment 2:11	EMED-09 Processing Report	
3 Petrophysics	Attachment 3:1	DUG Computer Processed Interpretation	
	Attachment 3:2	DUG Image Analysis Report	
	Attachment 3:3	Karish-1/Tanin-1 Digital Image Logs	
4 Geological Model	Attachment 4:1	Ragan Biostratigraphic Analysis	
	Attachment 4:2	Routine Core Analysis, Karish-1/Tanin-1	
	Attachment 4:3	Formation Pressure/Sampling Report & Data, Karish-1/Tanin-2	
5 Volumetrics			
6 Reservoir Engineering	Attachment 6:1	Eclipse Reservoir model	
	Attachment 6:2	FDP Production Forecasts excel data	
7 Facilities Development	Attachment 7:1	BFD FPSO Topsides Process - Scenatio 2	J20865B-P-DW-15146
	Attachment 7:2	PFD 800 MMscfd Future Phase Onshore Facilities	J20865B-P-DW-15045
	Attachment 7:3	PFD Scenario 2 Inlet Systems	J20865B-P-DW-15140
	Attachment 7:4	PFD Scenario 2 Sales Gas Compression	J20865B-P-DW-15141
	Attachment 7:5	PFD Scenario 2 Oil Stabilisation	J20865B-P-DW-15142
	Attachment 7:6	PFD Scenario 2 MEG, Produced Water Handling & Oil Dehydration	J20865B-P-DW-15143
	Attachment 7:7	FPSO Utility Interface Diagram - Scenario 2	J20865B-P-DW-15148
	Attachment 7:8	Heat & Material Balance JT Only Initial Phase and Future Phase	J20865B-P-DW-15031
	Attachment 7:9	Fluid Characterisation Summary	J20865B-P-TN-15001
	Attachment 7:10	Overall field layout	J20865B-U-LY-20000
	Attachment 7:11	FPSO Approaches Layout	J20865B-U-LY-20002
	Attachment 7:12	Subsea System Block Field Schematic	J20865B-U-LY-20001
	Attachment 7:13	Onshore Approach Layout Karish & Tanin	J20865B-U-LY-20003
	Attachment 7:14	FPSO & Drill Centre Approaches	J20865B-U-LY-20004
	Attachment 7:15	Flow Assurance Assessment Report	J20865B-U-RT-20021
	Attachment 7:16	Process and Utility Description	J20865B-P-RT-15003
	Attachment 7:17	Conceptual Layout Review Report	J20865B-L-RT-11003
	Attachment 7:18	Conceptual study basis	J20865B-A-RT-00004
	Attachment 7:19	Design & Constructability Review	
	Attachment 7:20	RAM Study Report	J20865B-P-RT-15006
	Attachment 7:21	Preliminary Flare System Sizing Calculation	J20865B-P-CA-15061
	Attachment 7:22	Subsea control system and Umbilical Definition Report	J20865B-U-RT-20026
	Attachment 7:23	Utility Summary Report	J20865B-P-RT-15004
	Attachment 7:24	Topsides Equipment list	J20865B-P-LI-15050
	Attachment 7:25	Offshore geophysical and geotechnical scope of work report	J20865B-U-RT-20020
	Attachment 7:26	Preliminary offshore flowline and pipeline mechanical design report	J20865B-U-RT-20023
	Attachment 7:27	Preliminary onshore pipeline design report	J20865B-U-RT-20024
	Attachment 7:28	Subsea structures definition report	J20865B-U-RT-20025
	Attachment 7:29	Preliminary wellheads and trees definition report	J20865B-U-RT-20027
	Attachment 7:30	Offshore Facilities DOR Valve Station	J20865B-L-DW-11021
	Attachment 7:31	Conceptual Table pre-feasibility (.xls)	
	Attachment 7:32	IO Summary Report (.ppt)	0036-EN-UK-PM-PRE-0001-F01
	Attachment 7:33	Granherne End of Feasibility Report	10432-KAR-RS-A-00001
	Attachment 7:34	Genesis Concept Engineering Summary Report	J20865-B-A-RT-00005
	Attachment 7:35	Kanf- Topsides Plat Plan	171W007-KA-00-L-XD-00001
	Attachment 7:36	Kanf-Preliminary Mooring Analysis	171W007-KA-00-J-RA-00002
	Attachment 7:37	Kanf- General Arrangement Plan	171W007-KA-00-L-XD-00002
	Attachment 7:38	Genesis-Flow Assurance Sumary (.ppt)	
8 Project Schedule and Cost estimates		Energean IEPCI - Budgetary Submission - Rev. 1 - 23.05.17	073560T001
		Long Lead Item List	171W007-KA-00-Z-LA-00002
9 Gas Sales			
10 Economics		Excel economic model	
11 Project Execution strategy		0. Installation Slide Pack	
		Project Note-Organisational development	ISR-GEN-RP-PJM-0027 Rev A -
		Energean Organisation maturation	
12 Operation, Control and Maintenance			
13 Health, Safety, Environment and Security	Attachment 13:1	HSE Philosophy	J20865A-F-PH-05001
	Attachment 13:2	Topsides Layout Philosophy	J20865A-L-PH-11001
	Attachment 13:3	ESIA Scoping Report	
	Attachment 13:4	HSE Plan	KAD-GEN-GE-HSE-001
	Attachment 13:5	Concept Safety Report	J20865B-F-RT-05001
14 Local Content development			
15 Risk Assessment	Attachment 16:1	Risk assessment workshop report	J20865B-A-RT-00009