ADX Energy Ltd.

Independent Evaluation Report – Kerkouane PSC, Offshore Tunisia

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Prepared For: ADX Energy Ltd.

By: ERC Equipoise Pte Ltd

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1. Summary

1.1. Introduction

ERC Equipoise Pte Ltd ("ERCE") was commissioned by ADX Energy Ltd ("ADX") to prepare an independent evaluation of the Contingent Resources in the Dougga discovery and the Prospective Resources in the Dougga SW prospect, in the Kerkouane PSC, offshore Tunisia.

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. Except for the provision of professional services on a time-based fee basis, ERCE has no commercial arrangement with any other person or company involved in the interests that are the subject of this report. ERCE confirms that it is independent of ADX Energy, its directors, senior management and advisers. ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The work has been supervised by Mr Stewart Easton. Stewart is the General Manager for the Asia Pacific Region, with over 21 years of experience in the oil and gas industry.

The Kerkouane licence covers an area of 3,080 km^2 in the Gulf of Hammamat offshore Tunisia, The Kerkouane licence was awarded in 2002 to previous Operator Grove Energy. ADX entered the licence in 2008 and in 2013 increased its interest in the licence interest to 100%. The Kerkouane licence is a Tunisian Production Sharing Contract (PSC). The licence is understood to be an exploration permit, that may be converted to an exploitation concession when a commercial discovery is made. The remaining licence commitment is to drill and test one appraisal well, Dougga-Sud. The licence documents and licence terms have not been reviewed or verified by ERCE as part of this independent evaluation. A summary of the Kerkouane licence interest held by ADX is given in Table 1-1.

Table 1-1: Licence Summary

Country	Licence	Discovery / Prospect	Operator	ADX Working Interest
Tunisia	Kerkouane PSC	Dougga / Dougga SW	ADX	100%

1.2. Data Provided

ERCE was provided with a dataset which comprised:

- Well data, where available, including composite logs and mud logs
- Open-hole well logs and petrophysical interpretation, where available
- Core data and analysis thereof, where available
- Well test data and formation pressure data
- Fluid analysis, including PVT
- Production data, including static and flowing pressure, where available
- Seismic interpretation, time and depth grids for the main producing intervals
- Static reservoir model
- Licence information

- 2D and 3D seismic data
- Project overview presentations
- Subsurface Information Memorandum
- Draft Facilities Information Memorandum
- TechnipFMC facilities feasibility study reports
- Well engineering reports and presentations prepared by Asia Well Engineering Services (AWES)
- Information from analogue fields in Tunisia
- ADX work files (e.g. production forecast, PVT files)

1.3. Work Completed

The dataset provided by ADX enabled ERCE to complete a comprehensive review of the:

- Hydrocarbons initially in place
- Contingent Resources at the 1C, 2C and 3C levels of confidence, where applicable
- Commentary of ADX's development scheme and associated preliminary cost estimation
- Prospective Resources at the Low, Best and High levels of confidence, where applicable

During the course of the evaluation, ADX provided ERCE personnel with information as detailed in Section 1.2. ERCE has relied upon ADX for the completeness of all the data provided. Nothing has come to ERCE's attention that would suggest that information provided by ADX was not complete and accurate. ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in the light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

The accuracy of any reserves, resources and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resource estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

ERCE has carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1. The full text can be downloaded from www.spe.org/spe-app/spe/industry/reserves/prms.htm

In the case of discovered resources (Contingent Resources) presented in this report, there is no certainty that it will be commercially viable to produce any portion of the resources.

We have reviewed the Prospective Resources and Geological Chance of Success (COS) associated with the Dougga SW prospect in ADX's Kerkouane PSC. We make independent estimates of Prospective Resources and COS for Prospects: that is features that are considered to be sufficiently well defined through analysis of geological and geophysical data that they are considered drillable targets. In the case of undiscovered resources (Prospective Resources) presented in this report, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

No site visit was undertaken in the generation of this report.

1.4. Summary of Results

The Kerkouane licence is located in the northern part of the Gulf of Hammamet offshore Tunisia. The licence contains three gas discoveries: Kerkouane, Labouka and Dougga. The Dougga gas condensate discovery is located in 330 m water depth about 45 km offshore the Cap Bon peninsula. Dougga was discovered in 1981 when Shell Tunisia drilled and tested Well Dougga-1. The discovery is considered to have potential for being developed, subject to results of further appraisal drilling.

The main reservoir in Dougga is the late Cretaceous Abiod carbonate formation, with the underlying Fahdene formation being a secondary reservoir. The Abiod formation is of low matrix porosity and permeability. The Fahdene is not considered a matrix reservoir, but is expected to be fractured and with limited volumes of gas in place. Natural fractures are expected to enhance the flow characteristics of both formations. The presence of extensive fracturing remains to be confirmed.

Well Dougga-1 was flow tested in both the Fahdene and the Abiod formations and the presence of gas with condensate was confirmed. Equipment failure resulted in early termination of the Abiod well test and limited data acquisition. The test rates were low (0.4 – 2.5 MMscf/d) with variable condensate content observed at surface. The variation in condensate content is understood to be a result of low gas flow rates combined with back production of water, causing slugging in the well during testing.

Fluid samples were gathered during the testing operations and later analysed in the laboratory. The gas has a high CO_2 content (18-30 Mol%) and a high level of rich components (C3+). An H_2S content of 50 ppm was measured during testing operations. The condensate density was measured at 59° API. The fluid composition, condensate yield and CO_2 content are uncertain as a consistent set of fluid analysis data is not available.

ADX plans to drill an appraisal well, Well Dougga-Sud in order to gather additional data and reduce the uncertainties related to the reservoir rock and fluids. The appraisal well is intended to prove the presence of an effective fracture system in the reservoir, establish that commercial flow rates can be achieved on a sustained basis (well productivity), and acquire improved fluid samples. This may enable sufficient reduction in the uncertainties currently associated with the discovery such that a decision regarding progression towards a development may be taken. The appraisal well is planned as a vertical well.

ADX has outlined a conceptual development plan for the Dougga discovery. The plan is based on a subsea development with a 45 km tie-back to a dedicated onshore gas processing plant at Cap Bon. Six wells are currently estimated to be sufficient to drain the field with a planned plateau rate of 100 MMscf/d raw gas. Subsea compression is assumed installed after several years in order to maximise the recovery of gas. Subsea compression is an emerging technology with only two field installations so far and is hence currently not considered as a proved technology. Plateau length and timing for gas compression is dependent on the resource potential and will be reviewed following appraisal of the discovery.

ERCE considers the following uncertainties to be of particular relevance to the potential development of the Dougga discovery. The appraisal well should aid in reducing these uncertainties and narrow the range of estimated resource potential.

- Degree of natural fracturing of the reservoir. An extensive fracture network is required in order to drain the field efficiently and to achieve commercial flow rates. There is a risk that the field is not extensively fractured, or that the appraisal well does not connect to the fracture network
- Fluids and inerts content of the gas can have a significant impact on facilities design, costs and operation.
- The proposed development concept has associated flow assurance challenges related to a long (45 km) offshore tie-back and use of emerging subsea compression technology in a field with corrosive fluids (high CO_2) and potential for water production. Flow assurance and hydrate management are also issues that need to be clarified once more data are available

ERCE has completed an independent and integrated assessment of the resource potential in the Dougga discovery. The evaluation confirms that the Dougga discovery has a significant resource potential. The results from the appraisal well will be important in confirming the resource potential and establishing a firmer basis for a development plan. As a consequence, the resource estimates are currently classified as Contingent Resources, in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS).

Summaries of the gas (after deduction of inert gas), condensate and LPG Contingent Resources associated with ADX's assets in the Kerkouane PSC, Offshore Tunisia, are presented in Table 1-2, Table 1-3 and Table 1-4. The estimates are based on a development concept where subsea compression is utilised. Should a subsea compression system not be feasible for the development of the Dougga discovery, or if an alternative development be adopted without the installation of compression the resulting resources may be lower than our estimates.

Table 1-2: Summary of ADX's gas Contingent Resources, Kerkouane PSC

Country	Licence	Discovery	Gross Contingent Resources (Bscf)			Working Interest (%)	W.I. Contingent Resources (Bscf)		
			1C	2C	3C		1C	2C	3C
Tunisia	Kerkouane PSC	Dougga	238	405	722	100	238	405	722

Table 1-3: Summary of ADX's condensate Contingent Resources, Kerkouane PSC

Country	Licence	Discovery	Gross Contingent Resources (MMbbl)			Working Interest (%)	W.I. Contingent Resources (MMbbl)		
			1C	2C	3C		1C	2C	3C
Tunisia	Kerkouane PSC	Dougga	15	31	64	100	15	31	64

Table 1-4: Summary of ADX's LPG Contingent Resources, Kerkouane PSC

Country	Licence	Discovery	Gross Contingent Resources (MMbbl)			Working Interest (%)	W.I. Contingent Resources (MMbbl)		
			1C	2C	3C		1C	2C	3C
Tunisia	Kerkouane PSC	Dougga	19	32	56	100	19	32	56

ERCE has assigned the Contingent Resources to the Dougga discovery as Development Unclarified. ERCE considers that a future development of Dougga is contingent on:

- The appraisal Well Dougga-Sud is successfully drilled and tested and acquires representative reservoir information and fluid samples
- Well Dougga-Sud broadly confirms the current assumptions about reservoir quality and fracture distribution and establishes that future horizontal development wells will be able to flow at the required commercial flow rates sufficient to support the proposed development plan
- The preparation and approval by all stakeholders of a development plan

ERCE has assessed the chance of development as 70%. The chance of development has not been applied to the tabulated volumes.

Approximately 7 km to the southwest of the Dougga discovery lies the Dougga SW prospect, which straddles the Kerkouane PSC. Approximately 41% of the volumes are located within the PSC. The majority of the structure is covered by the same 3D seismic dataset that covers Dougga, with the remaining southwestern area of the structure mapped on 2D seismic lines. The reservoir targets are the same as discovered at Dougga, the Abiod (matrix and fractures) and Fahdene (fractures only). We have completed an independent evaluation of the

Prospective Resources in the Dougga SW prospect. Several other exploration prospects in the PSC were not reviewed by ERCE. We consider the geological chance of success (COS) to be 30%. Summaries of the unrisked gas and condensate Prospective Resources are presented in Table 1-5. Note that these volumes are for the gross structure and include volumes outside of the Kerkouance PSC.

Table 1-5: Summary of ADX's gas Prospective Resources, Dougga-SW, Kerkouane PSC

Country	Licence	Prospect	Gross Unrisked Prospective Resources (Bscf)		
			Low	Best	High
Tunisia	Kerkouane PSC	Dougga SW	383	762	1550

Table 1-6: Summary of ADX's condensate Prospective Resources, Dougga-SW, Kerkouane PSC

Country	Licence	Prospect	Gross Unrisked Prospective Resources (MMbbl)		
			Low	Best	High
Tunisia	Kerkouane PSC	Dougga SW	15	37	88

2. Dougga Discovery, Kerkouane PSC, Offshore Tunisia

2.1. Discovery Description

The Dougga discovery is located in the Kerkouane PSC some 45 kilometers offshore Cap Bon, Tunisia, in a water depth of 330 m (Figure 2.1). The discovery was made when Well Dougga-1 was drilled by Shell in 1981 and tested gas plus condensate at low rates from the Cretaceous Abiod and Fahdene carbonate formations. Dougga-1 is the only well on the structure. ADX is Operator and holds 100% of the Kerkouane PSC. ADX joined the licence in 2008 and in 2010 jointly acquired 618 km^2 of dual sensor 3D seismic. In 2013 ADX acquired the remaining 40% interest.

The 3D seismic data identified an updip extension of the structure to the west of Well Dougga-1(Figure 2.3). ADX plans to drill an appraisal well, Dougga-Sud, 2 kms to the southwest of Well Dougga-1 and an estimated 190 m updip (Figure 2.3). The aim of the Dougga-Sud well is to confirm the extension of the field discovered by Dougga-1, appraise net pay in an updip location, prove the productivity and assess the degree of fracturing of the Abiod Formation, and to gather reliable fluid samples.

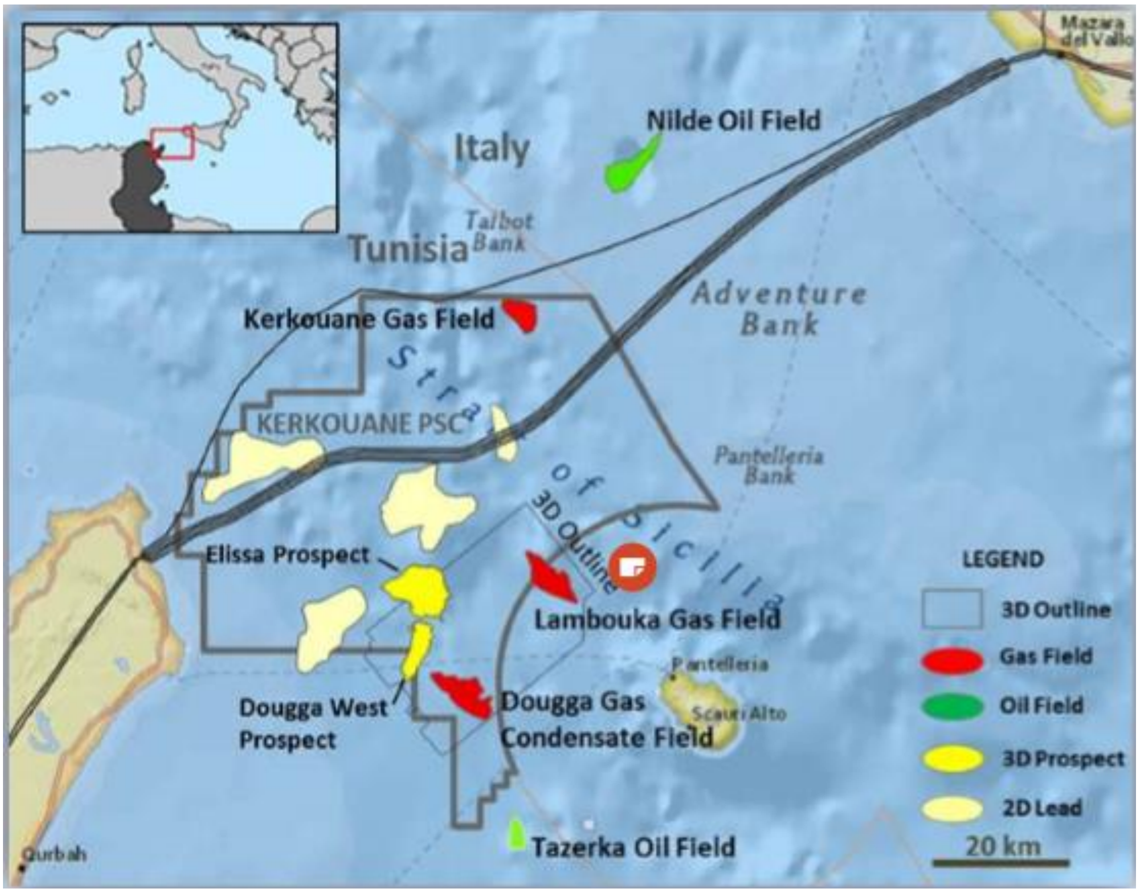

Figure 2.1: Location map of the Dougga Discovery, Kerkouane PSC

2.2. Geophysical Aspects

The Dougga discovery is covered by 2D and 3D seismic, the latter acquired in 2010. ADX provided ERCE with the full 3D dataset and ADX's interpretation of all key horizons including the top Abiod, top Fahdene and horizons above the reservoir.

2.2.1. Seismic and Depth Interpretation

The seismic is good quality and the reservoir horizons, Abiod and Fahdene are readily identified. The Abiod and Fahdene horizons are both picked on a seismic peak. The Abiod is a strong reflector that can be picked with confidence across the main Dougga field. The Fahdene reflector is weaker but still traceable across the structure. Faulting is complex and offsets can be clearly seen at the shallower Ain Grab horizon and in the overburden. ERCE has found the horizon and fault interpretation on the 3D seismic data to be reasonable and have accepted it without amendment.

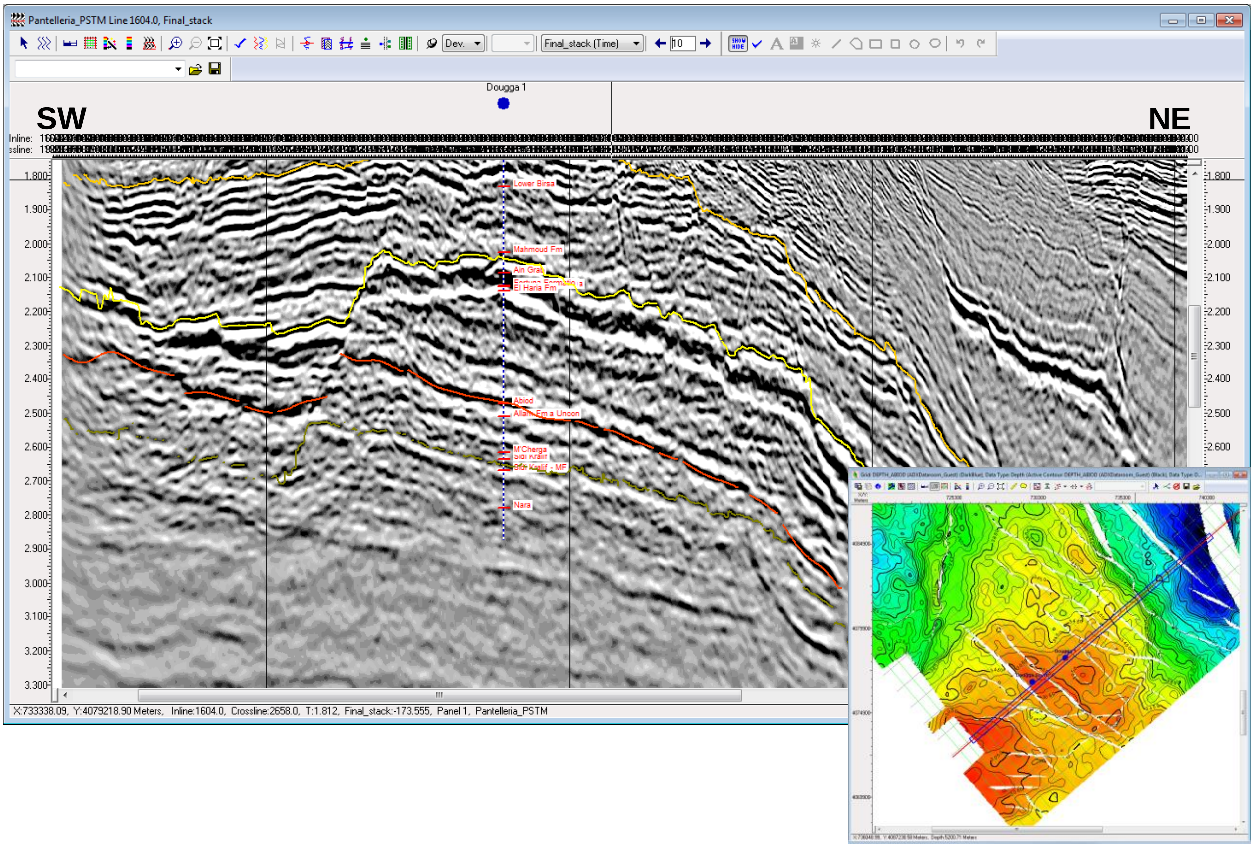

Figure 2.2: Arbitrary line (twt) through the Dougga-1 well

The interpretation reveals that the Abiod appears to thicken updip, to the west suggested to be the result of erosion by the Maastrichtian unconformity. ADX estimates that the thickness increases to some 110m, an increase of some 50 m over that observed in Well Dougga-1.

A multi-layer depth conversion was undertaken using the seismic stacking velocities conditioned to the available regional well data. Key horizons for the depth conversion were Seafloor, top Birsa, top Ain Grab and top Abiod. With only one well in the structure the depth interpretation is open to uncertainty, but ERCE accepts that the current ADX interpretation is fit for purpose.

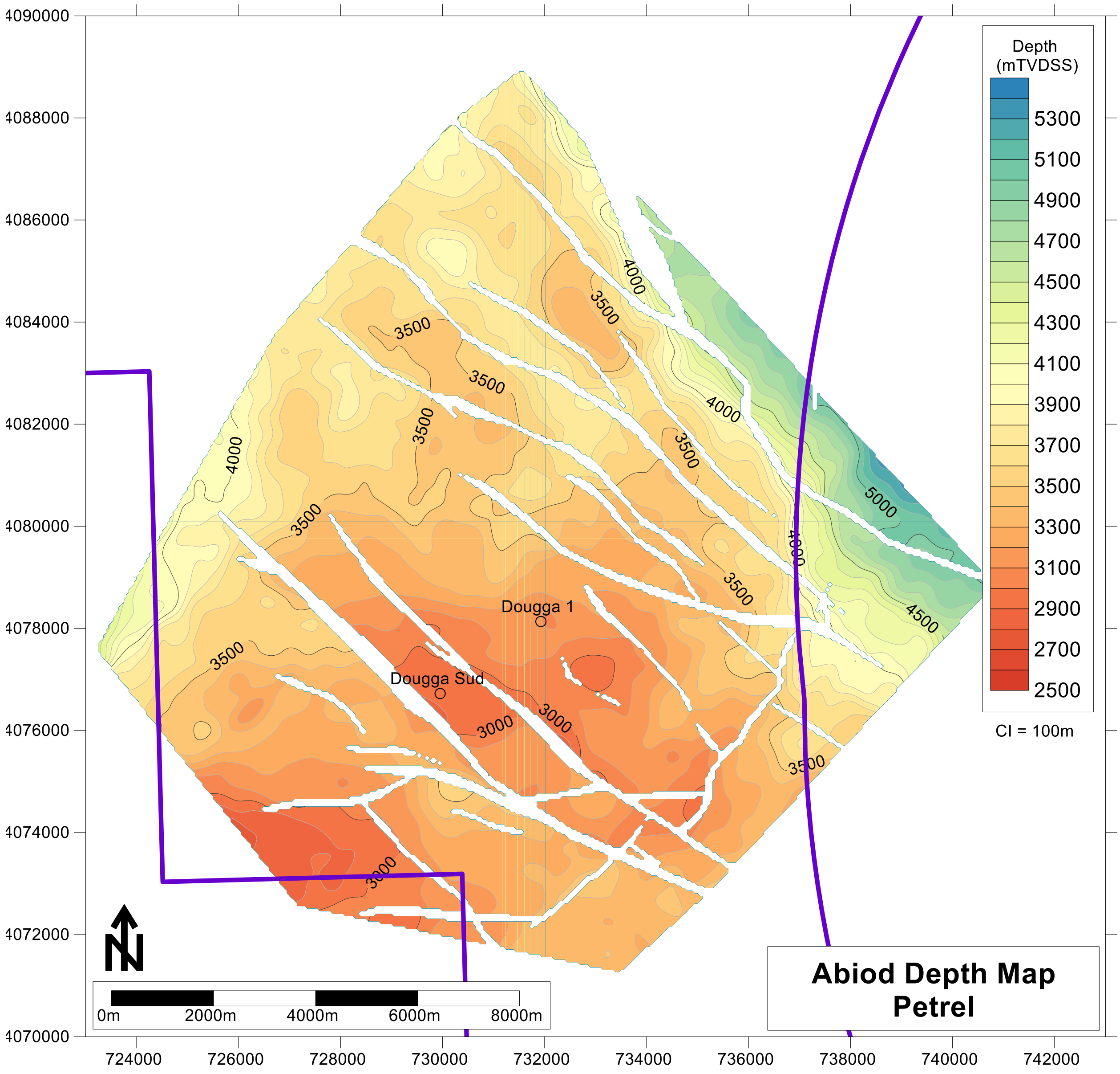

Figure 2.3: Structural Depth Map of Top Abiod

2.3. Geological Evaluation

The main reservoir interval is the Campanian Abiod chalky limestone with additional gas being present in the underlying Fahdene (previously termed the Allam). The gas bearing section comprises limestone (occasionally argillaceous), claystones and marls. Fractures are also believed, from analogue fields in Tunisia, to be an important element of the reservoir. Abiod is considered a Type II fractured reservoir (after Nelson 2001), where there is contribution from both matrix and fractures, while the Fahdene is a Type I reservoir where gas is reservoired solely in the fractures.

The Abiod and Fahdene were deposited in a deep shelf setting. The Abiod is often described as a chalk within Tunisia. From the sidewall samples, mudlog sample descriptions and interpretation of the logs, the main reservoir section is interpreted to comprise clean fine-grained mudstones and wackestones with occasional more argillaceous limestone and claystones. Claystones also occur in the Fahdene. Matrix porosities in Well Dougga-1 are general low, between 1 and 12%, but the well did encounter up to 18% in the upper part of the Abiod Reservoir. The Dougga-1 well was not cored, but is it is anticipated from analogues that matrix permeability will be at best a few millidarcies.

Fracture porosity is an important element of gas production and storage. It has been estimated by ADX to be 0.65% based on the analysis of a paper by Weber and Bakker (1987). Based on ERCE's regional and broader experience, we consider this value to be at the higher end of the range. For example, the highly fractured and thrusted structures of Kurdistan are generally in the range of 0.2 to 0.4% fracture porosity. These fields are associated with significant mud losses, good test rates and high well productivities.

The drilling data from Well Dougga-1 indicates no significant mud losses during drilling and the test rates were low, 0.5 to 2 MMscf/d. Partial losses, back flow to the mud pits and significant losses during the abandonment of the well do, however, indicate the presence of fractures. At this stage ERCE would assign a lower range of fracture porosity, 0.02 to 0.7%. Data acquisition in the planned vertical Dougga Sud well is expected to help to confirm and narrow this broad range.

Most naturally fractured reservoirs have a predominance of sub-vertical fractures. As a consequence, a vertical appraisal well will likely contact less fractures than a deviated well which would have a higher chance of success in terms of proving the presence of fractures and assessing the fracture network.

2.4. Petrophysical Evaluation

ERCE has not undertaken an independent petrophysical evaluation of Well Dougga-1 but has been provided with two previous evaluations; Hunt-Wallace and Reservoir Minds in 2016. ERCE has accepted these two interpretations as a reasonable basis for the estimation of resources.

Figure 2.4 shows a CPI of the well based on the Reservoir Minds interpretation. The Abiod is shown as a clean limestone with the main porous section occurring in the uppermost 25-30 m with porosity varying between 7 and 18%. Below this interval the formation generally exhibits porosity between 1 and 12%.

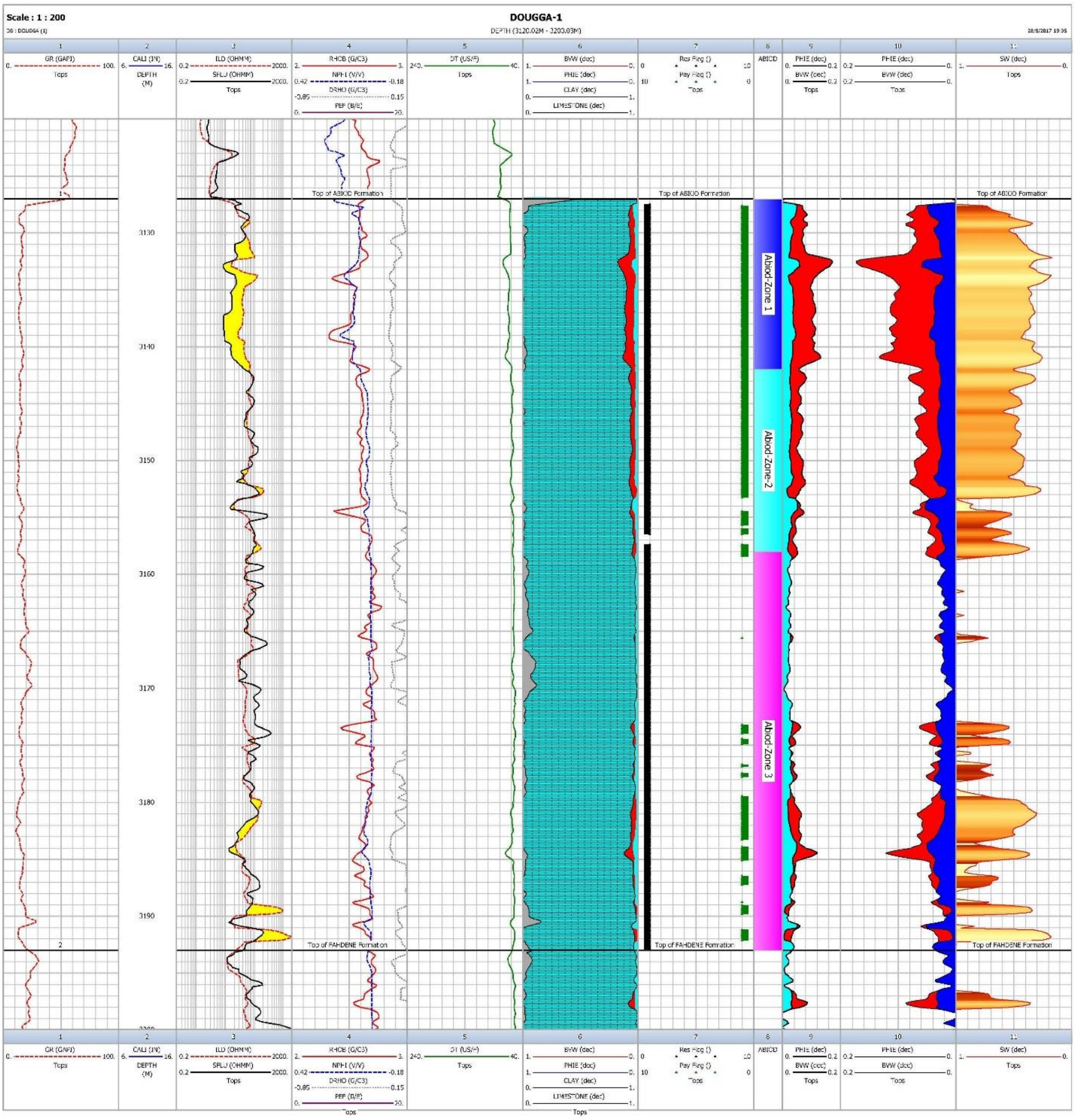

Figure 2.4: Petrophysical evaluation of Well Dougga-1 (depth in mMD)

2.4.1. Sums and Averages

ADX uses net pay cutoffs of 4% porosity and 75% water saturation. Table 2.1 shows the comparison of the Hunt-Wallace and Reservoir Minds average petrophysical parameters. While there are differences in individual parameters, the overall net hydrocarbon thickness (HCPm) is similar (Table 2-1). On this basis ERCE has used the Reservoir Minds interpretation as the basis of its evaluation, as did ADX.

Table 2-1 Comparison of Petrophysical Parameters

Net Pay 4% Phi 75%Sw	Top (mMD)	Base (mMD)	Gross (m)	Net (m)	NTG (dec)	Phi (dec)	Sw (dec)	HCPm (m)
Hunt-Wallace	3127	3193	66	32.6	0.49	0.078	0.313	1.75
Reservoir Minds	3127	3193	66	37.6	0.57	0.076	0.416	1.67
Net Pay 6% Phi 75%Sw	Top (mMD)	Base (mMD)	Gross (m)	Net (m)	NTG (dec)	Phi (dec)	Sw (dec)	HCPm (m)
Hunt-Wallace	3127	3193	66	21.0	0.32	0.092	0.282	1.39
Reservoir Minds	3127	3193	66	25.1	0.38	0.089	0.385	1.37
Volumetric Inputs (Mid)					0.71	0.086	0.397	

2.5. Hydrocarbons Initially in Place (HIIP)

We have calculated HIIP probabilistically and a range of Gross Rock Volume (GRV) has been estimated. The low case is based on a gas down to (GDT) at 3,296 mTVDSS (Section 2.6.2) and an area comprising the fault block of Well Dougga-1 and the adjacent Dougga Sud fault block to the south-west. The fault separating these two blocks dies out to the north west within the area of the presumed GDT, hence both blocks are interpreted to be in hydraulic communication. The high case GRV assumes the gas water contact (GWC) occurs at a depth of 3,600 mTVDSS, which coincides with the disappearance of the main bounding fault in the south-west and a possible gas chimney effect on the seismic. While the interpretation of gas shows in fractured formations is difficult and open to significant uncertainty, there are possible gas shows down to this level (and deeper). The mid case GRV is the P50 number from a log-normal distribution using the low and high case GRVs as P90 and P10 inputs.

A structural spill of some 3,350 mTVDSS is seen on the top Abiod depth structure to the east and south-west (across the main bounding fault). Therefore, to achieve the high case GRV model, the sealing of faults must be invoked.

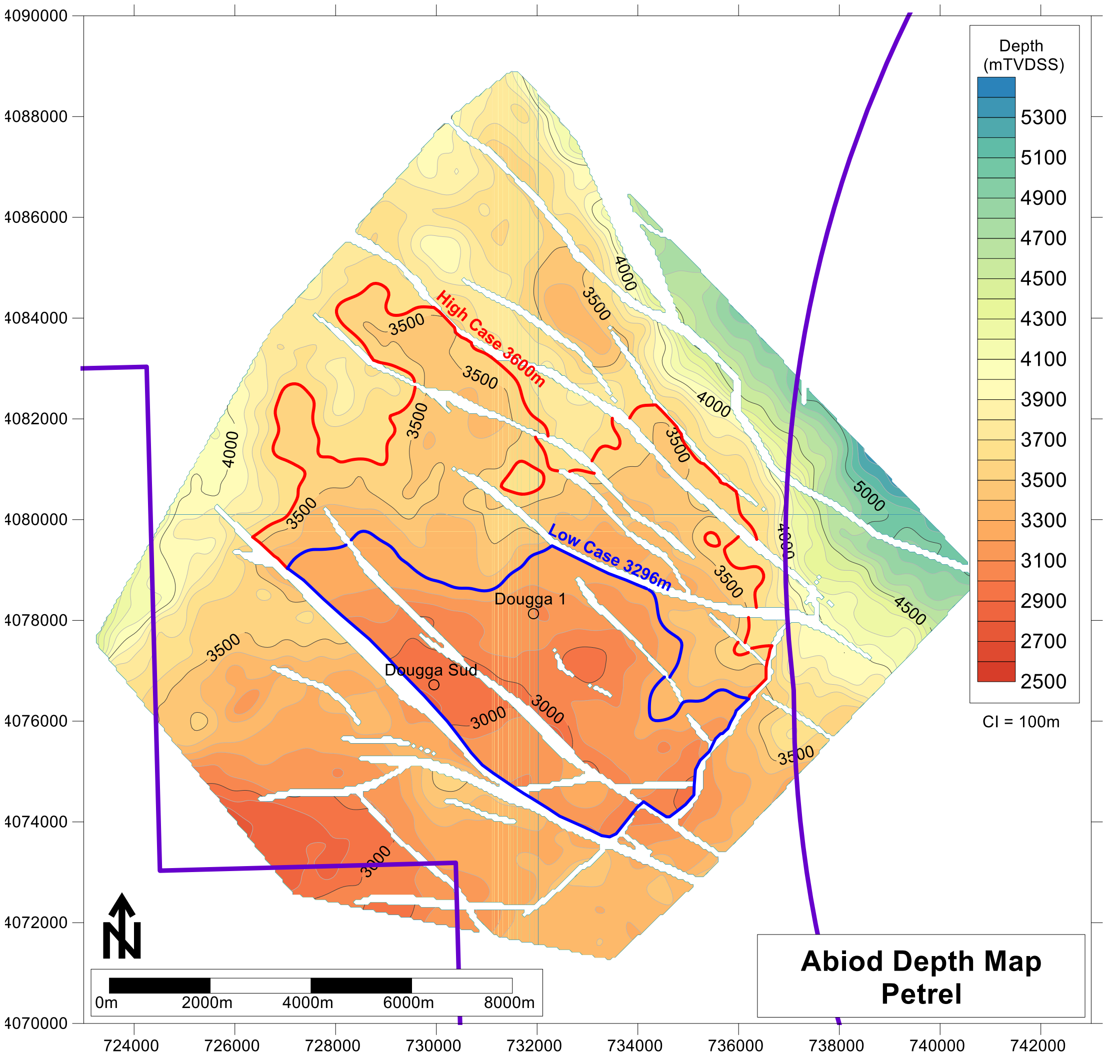

Figure 2.5: Dougga Low and High Case GRV Polygons and contact

The reservoir parameters used in our evaluation of the Abiod are shown in Table 2-2, only the low and high case numbers are used as inputs into the distributions for the probabilistic calculations. ERCE's mid case parameters were derived from the averages determined in Well Dougga-1 (Table 2-1), but adjusted (volume weighted) to account for the interpreted increase in thickness of the better quality uppermost layer updip into the Dougga Sud block. The greater volume of layer A increases the overall average. A reasonable range of parameters has been applied to define a low and high case. The low case reflects the parameters estimated in the Dougga-1 well.

From our experience of similar reservoirs we have assumed that fracture porosity ranges between 0.02 and 0.7% with a mid case value of 0.12% (based on a log-normal distribution). The lower end of the range reflects the lack of losses during drilling and low test results from the well and in the high case the possibility that losses experienced while abandoning the well may indicate a better developed fracture system.

The Fahdene is assumed to be a Type I reservoir (no matrix contribution, only fractures) and therefore is evaluated using the same fracture porosity range as the Abiod and a GRV range of 2,684 – 6,257 – 14,587 MMm3.

Table 2-2: Input parameters for Abiod (Matrix) volumetric calculations

ERCE Deterministic Case	GRV (MMm3)	N/G (dec)	Porosity (dec)	Sg (dec)	GEF (scf/rcf)
Low	2162	0.5	0.07	0.5	208
Mid	2970	0.7	0.085	0.6	227
High	4079	0.9	0.10	0.7	250

Table 2-3 Input parameters for Abiod (Fractures) volumetric calculations

ERCE Deterministic Case	GRV (MMm3)	N/G (dec)	Porosity (dec)	Sg (dec)	GEF (scf/rcf)
Low	2162	1	0.0002	0.93	208
Mid	2970	1	0.00118	0.95	227
High	4079	1	0.007	0.97	250

Table 2-4 Input parameters for Fahdene (Fractures) volumetric calculations

ERCE Deterministic Case	GRV (MMm3)	N/G (dec)	Porosity (dec)	Sg (dec)	GEF (scf/rcf)
Low	2684	1	0.0002	0.93	208
Mid	6257	1	0.00118	0.95	227
High	14587	1	0.007	0.97	250

Table 2-5 shows the range of GIIP for the Abiod and Fahdene formations and the sum for the Dougga discovery.

Table 2-5: Dougga gas initially in-place (probabilistic estimates)

	GIIP (Bscf)			
	Low	Mid	High	Mean
Abiod (Matrix)	512	829	1319	883
Abiod (Fractures)	4	27	164	73
Fahdene (Fractures)	8	57	404	184
Dougga (Probabilistic Sum)	**600**	**1001**	**1756**	**1139**

2.6. Reservoir Engineering Evaluation

2.6.1. Well Tests

The Dougga-1 well was flow tested in two intervals, one in the Abiod and one in the Fahdene formation (Figure 2.6). The well was cased and cemented prior to perforating and flow testing. Such a completion is not an ideal way to test a fractured reservoir, as fractures may be shut off / filled by the cement behind casing. The well test operations experienced a number of equipment problems, which impacted on the results of the well tests - the downhole pressure gauges and the seal assembly failed during operations. The perforation guns used were through-tubing low penetration guns. The well was stimulated with 15% HCl acid.

As a result of equipment failure, no data for estimating reservoir pressure or undertaking transient build-up analysis from either of the two well tests are available.

However, the tests did prove the presence of gas and several fluid samples were taken. The test rates were relatively low, indicating that if fracturing is present in the reservoir in the vicinity of the well the perforations did not intersect highly conductive fractures, or that the acid stimulation job was not sufficient to contact a fracture network. The well may not have been fully cleaned up during the test with low gas withdrawal rates. Water was produced together with the gas at significant volumes, however the salinity of the water indicates that this is from well operations rather than being formation water. It is noted that when killing the well, 2500 bbls of water was lost in three hours, which could indicate connection to fractures at this stage of the operations.

Well test No.1, in the Fahdene formation saw low gas rates, between 0.4 – 0.8 MMscf/d. Likely as a result of the low rates and the water, the well appears to have been slugging, and measurements of condensate gas ratio are erratic varying from 0 to over 100 bbl/MMscf. However, the last test period in the Fahdene was stable for some time albeit at low rate, enabling a steady measurement of condensate/gas ratio (CGR) of 25 bbl/MMscf. Flow rates and decreasing well head pressure during the test indicated that the well had contacted a limited volume of gas in the Fahdene formation.

Well test No.2, in the Abiod formation, saw higher gas rates than the Fahdene, with an initial rate of 2.5 MMscf/d. No condensate was observed on the test, similar to the initial flow in Fahdene. Water was produced during the test, which is interpreted to be from well operations rather than formation water. The well test was aborted after three hours due to seal assembly failure. Flow rates and decreasing well head pressure during the test (Table 2-6) indicated that the well had contacted a limited volume of gas in the Abiod formation.

Table 2-6 Dougga-1 well test data from the Abiod Formation

	Pressure		Rates			Calculated Values			
Time	THP (psig)	P Sep (psig)	Gas Rate (MMSCFD)	Cond (b/d)	Water (b/d)	Total Liquid (b/d)	CGR (stb/mmscf)	GLR (mscf/bbl)	WGR (stb/mmscf)
19:00	610	75	2.426						
19:30	600	75	2.318		116.8	116.8	0.0	19.8	50.4
20:00	488	75	2.118						
20:30	398	75	1.77		52.8	52.8	0.0	33.5	29.8
21:00	360	75	1.322						
21:30	335	75	1.082		61.7	61.7	0.0	17.5	57.0
22:00	315	75	1.057		230.9	230.9	0.0	4.6	218.4

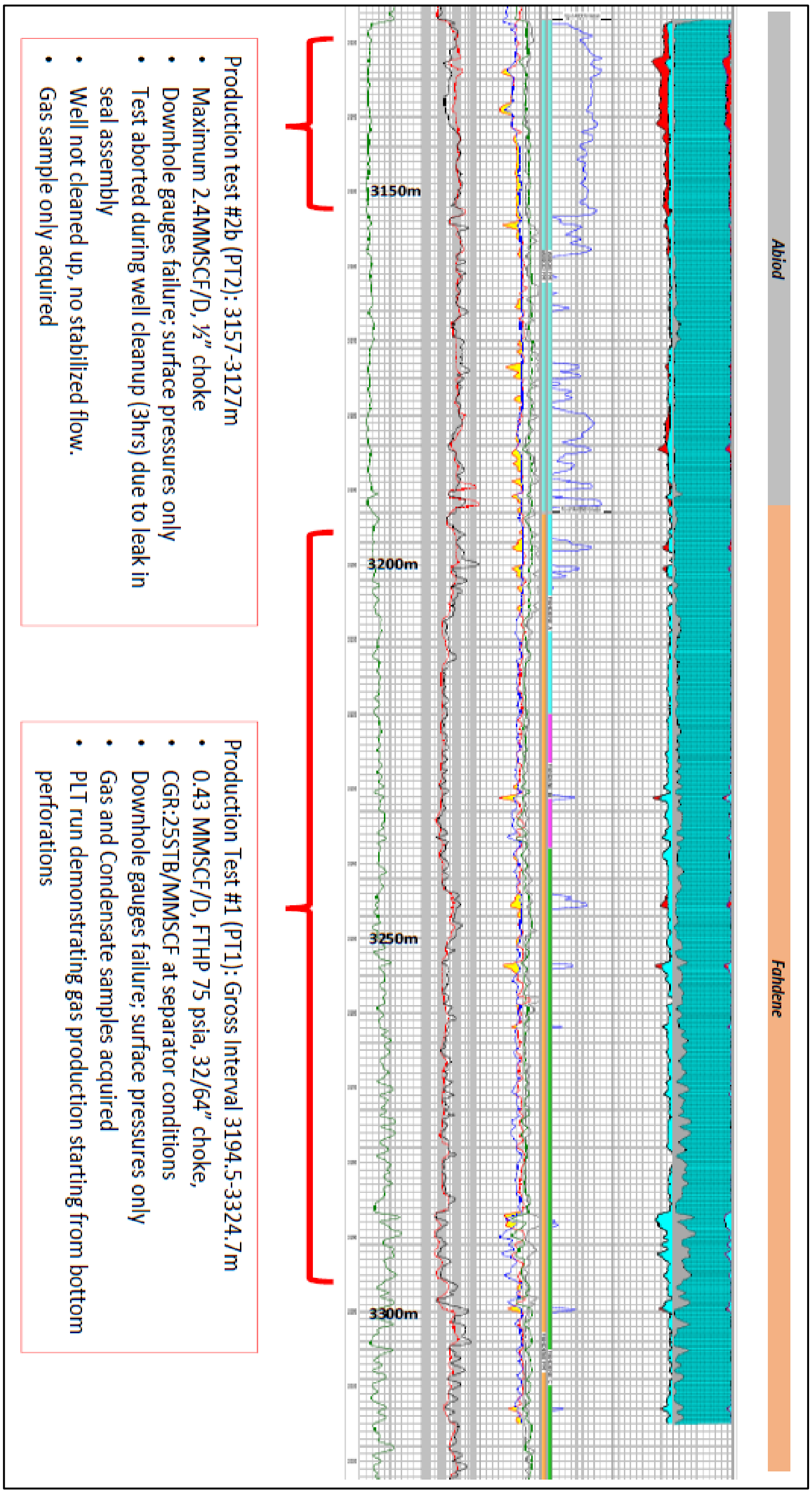

Figure 2.6 Dougga-1 DST intervals

A key objective of the planned appraisal well Dougga Sud is to obtain higher quality well test data, enabling a reduction in the uncertainties related to the Dougga-1 well tests.

2.6.2. Reservoir Pressures and Fluid Contacts

The only available pressure data from the gas bearing reservoirs are two RFT (Repeat Formation Tester) pressure points. Most of the RFT data points were failures due to either tight reservoir or seal failure. No pressure data from the water zone are available. Pressures from the shallower, water bearing Birsa formation show that the reservoir pressure is close to hydrostatic but slightly over-pressured.

The two pressure points in the Abiod are offset with a difference in pressure of about 250 psi. It is considered likely that one of the points, if not both, is not valid due to super-charging, and it is therefore considered unlikely that the offset in pressure implies two separate pressure regimes in the Abiod, although this cannot be ruled out.

Figure 2.7 shows the RFT pressures from Well Dougga-1. Reservoir pressure in the Abiod is approximately 5000 psia.

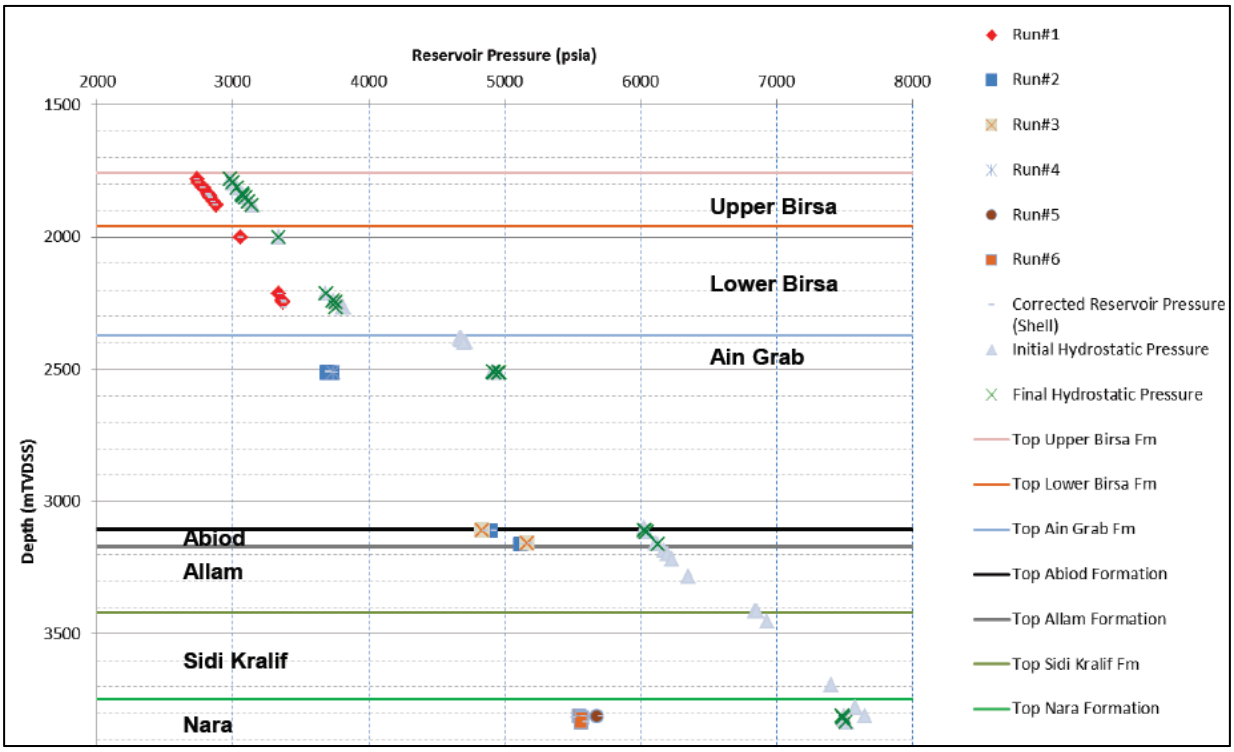

Figure 2.7: Pressure plot for Well Dougga-1

The low case gas down to (GDT), 3,296 mTVDSS (3,320 mMD), has been defined as the lowest level that gas was produced in DST-1 within the Fahdene. Flow was proven at this lower level and several shallower levels within the Fahdene by the results of the PLT flowmeter run during the well test. The lowest interval occurs within interbedded limestone and claystone. The claystone could create a vertical barrier locally to the well, but away from the well displacement along fracture zones and faults may create connectivity.

Assuming a similar water pressure in Abiod as the Birsa, and using the shallowest RFT point, which is recorded in the best reservoir interval (c.18% porosity), a gas-water contact depth of between 3,350 and 3,400 mTVDSS can be interpreted, which is consistent with the contact range described in Section 2.5.

2.6.3. Fluid properties

There is significant uncertainty regarding the fluid properties for the Dougga gas and in particular the condensate gas ratio (CGR) due to the lack of a coherent set of production tests.

The base case assumption is that the final and most stable flow period from the Fahdene formation is the most representative in terms of fluids produced. The test observed a CGR of 25 stb/MMscf at separator conditions. Table 2-7 shows the resulting reservoir fluid composition which has been estimated based on a recombination of the Abiod gas with the Fahdene condensate. The low case assumption is based on the composition of the gas sample taken at separator conditions from the Abiod test. Although the Abiod test failed early and did not recover condensate to surface it is considered likely that the Abiod gas contains condensate based on the Fahdene early test data where it took time for significant condensate yields to be observed. The high case assumption is based on test data from the Abiod formation in Well Tazerka-1 in the Tazerka field analogue which has a higher CGR but still within the range seen in the Dougga tests. The Dougga gas is a wet gas with laboratory measurements indicating no dewpoint or liquid dropout at reservoir temperature. Whilst this is unusual, it stems from a combination of a high CO_2 content, a high C_2-C_3 content and a high reservoir temperature. Table 2-8 shows the gas expansion factor (GEF) and CGR estimated for the low, mid and high cases. In the calculation of Contingent Resources the low case CGR has been used as a P95 input, and the high case CGR used as a P10 input. The mid case CGR of 41.1 stb/MMscf is derived from the C5+ yield from the compositional analysis, and this sits at approximately P50 using a lognormal distribution with the P95 and P10 input described.

The gas samples show a CO_2 content of about 30 mol%, which will have to be removed at the planned onshore gas processing plant to meet sales gas specifications. There is uncertainty in the CO_2 content as one gas sample had 18% CO_2 measured in the laboratory versus 30% measured during well testing.

A H_2S level of 50 ppm was measured during the well testing operations.

It should be noted that a higher ultimate condensate yield than seen in the well tests is likely as a result of additional liquids being removed at the gas plant. The project is expected to include LPG extraction, with an estimated yield of 45 bbl/MMscf raw gas (assuming a 100% recovery efficiency of LPG). This is based on the compositional analysis shown in Table 2-7.

An important objective of the planned appraisal well will be to obtain higher quality fluid data, enabling a reduction in the uncertainties related to the fluid samples from Well Dougga-1 and CGR observations.

Table 2-7: Compositional Analysis of PVT Samples from Well Dougga-1

Component	Reported molar percentage
N2	0.84
CO2	30.80
C1	46.59
C2	11.89
C3	4.07
iC4	1.07
nC4	1.25
iC5	0.75
nC5	0.46
C6	0.96
C7+	1.32
Total	**100**

Table 2-8: Gas Properties for Sample from Well Dougga-1

Item	Units	Low	Mid	High
GEF	scf/rcf	208	227	250
CGR	stb/MMscf	17.9	41.1	81.1

2.6.4. Development Concept and Recovery Factors

The Dougga discovery is located offshore at a water depth of about 330 m. ADX is planning to develop the Dougga gas as a subsea development with transport of the raw, multiphase fluid stream onshore through a 45 km pipeline. Hydrate and corrosion inhibitors are planned. Gas will be processed at a new onshore gas processing plant, where CO_2 will be removed, liquids extracted and gas conditioned to sales specification. A total of six subsea wells are estimated to be required, with an option for a seventh well depending on field performance. Figure 2.8 shows the proposed locations of the development wells. Subsea gas compression is planned to be installed after several years in order to optimise the recovery efficiency. A compression ratio of three has been assumed, which is expected to enable a reduction in flowing well head pressure from 85 Bar to 28 Bar resulting in a significant reduction in the field abandonment pressure. It should be noted that subsea compression is an emerging technology and not currently considered a proven technology. At the current time only two examples of subsea compression have been installed worldwide (on the Åsgard Field and Gullfaks, Norway, 2015).

ADX is planning to produce the field at a plateau rate of 100 MMscf/d, with an expected plateau length of approximately 10 years in the mid case. This will require a production potential of about 20 MMscf/d per well.

The assumed recovery mechanism is depletion drive (gas expansion drive). The range of assumed gas recovery factors is shown in Table 2-9, this range assumes subsea compression is installed and reflects current reservoir uncertainties, including fracture distribution, potential for water influx and reservoir fluid composition. The Dougga gas is expected to be a wet gas with no liquid drop-put in the reservoir based on the available fluid data.

An appraisal well is planned and is required in order to confirm well productivity, assess the degree of fracturing of the reservoir and obtaining reliable fluid data prior to making a development decision.

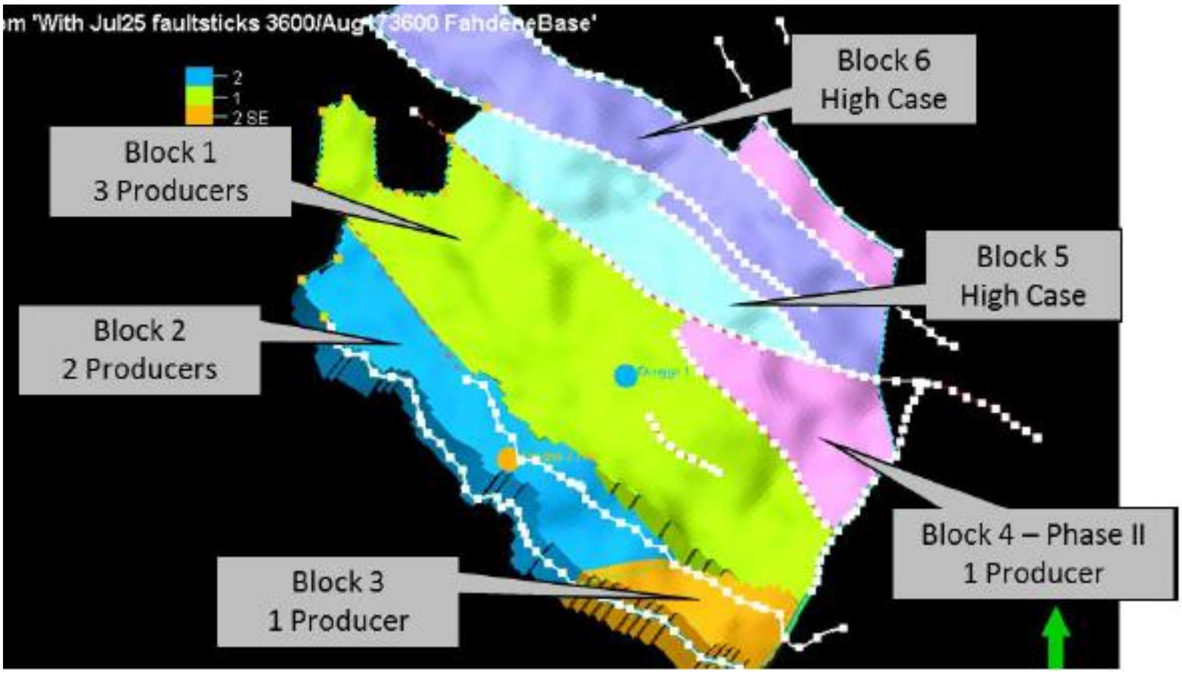

Figure 2.8: Proposed Production Well Locations

Table 2-9: Gas and Condensate Recovery Factors for Dougga

Item	Low	Mid	High
Recovery Factor (%)	63	71	79

2.6.5. Contingent Resources

ERCE has estimated Contingent Resources, gas and condensate, for Dougga (Table 2-10) by applying our estimates of recovery factors (Table 2-9) and CGR (Table 2-8) to our estimates of GIIP (Table 2-5) probabilistically. The estimates assume a development concept where subsea compression is utilised and that flow assurance can be achieved across the range of pressure depletion and liquid production rates which may occur.

Table 2-10: Dougga Contingent Resources

	Contingent Resources			
	1C	2C	3C	Mean
Gross Gas (Bscf)	421	709	1253	809
Gas Net of Inerts (Bscf)	238	405	722	463
Condensate (MMbbl)	15	31	64	37
LPG (MMbbl)	19	32	56	36

The conversion (shrinkage factor) from raw gas to gas net of inerts is in the range of 0.54-0.58-0.60 depending on the CGR content. This conversion factor takes into account removal of CO_2 and gas shrinkage when liquids are removed. It does not include a deduction for fuel gas, which may be included in the future according to plant simulations.

ERCE has assigned the Contingent Resources to the Dougga discovery as Development Unclarified. ERCE considers that a future development of Dougga is contingent on:

- The appraisal Well Dougga-Sud is successfully drilled and tested and acquires representative reservoir information and fluid samples
- Well Dougga-Sud broadly confirms the current assumptions about reservoir quality and fracture distribution and establishes that future horizontal development wells will be able to flow at the required commercial flow rates sufficient to support the proposed development plan
- The preparation and approval by all stakeholders of a development plan

ERCE has assessed the chance of development as 70%. The chance of development has not been applied to the tabulated volumes.

3. Facilities and Wells Review

3.1. Project Maturity

ADX has undertaken an appropriate level of concept development work in light of the outstanding ambiguity in the Basis of Design pending results of the forthcoming Dougga-Sub appraisal well. The project is considered to be in the Appraise or Concept stage, as illustrated in Figure 3.1.

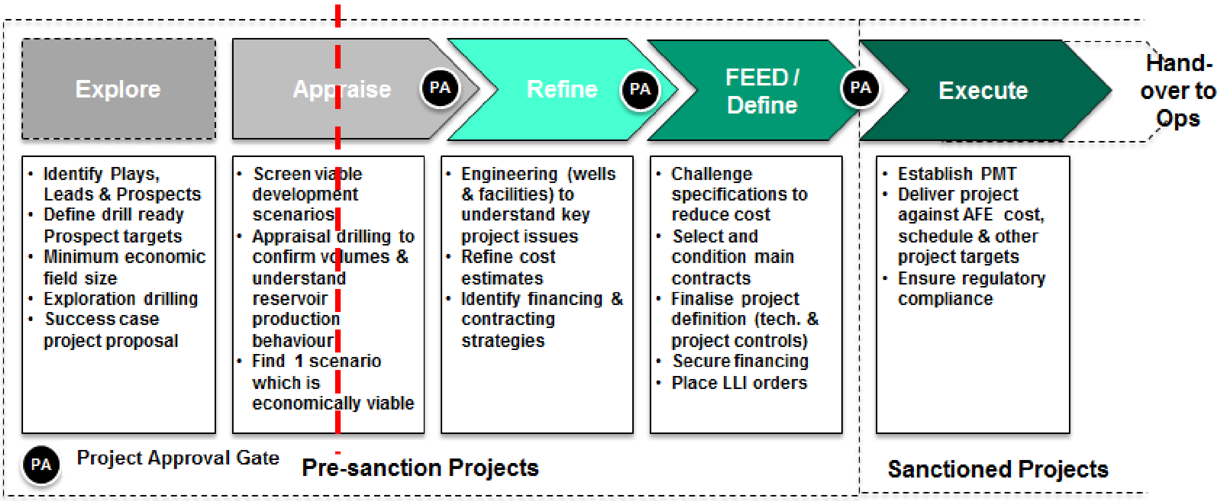

Figure 3.1: Project Maturity Status

3.2. Facilities Concept

The base case concept is for a subsea to shore development (Figure 3.2), with six planned development wells (including appraisal-keeper from Dougga-Sud). This lies well within industry experience, albeit with a number of key challenges which are highlighted in the following sections.

Figure 3.2: Subsea to Shore Development Concept

The robustness of the concept is highly dependent on fluid composition. Current assumptions indicate that the subsea to shore system can function satisfactorily. However, the system may be sensitive to increases in condensate or water to gas ratios (CGR/WGR). ADX and TechnipFMC have taken steps to address current uncertainties by assuming conservative inputs to critical elements of the subsea concept design work undertaken. Key uncertainties and their implications are summarized as:

- As yet the gas-water-contact and formation water composition have not been definitively determined. The expectation is depletion drive will work with limited formation water production (1 bbl/MMscf). If significant formation water production occurs, this may have a detrimental effect on multi-phase tie-back flow and production flow assurance, although this has been addressed preliminarily by assuming 1000 bbl/d of water production for flow assurance studies – an order of magnitude above the assumed production rate.
- Significant uncertainties in Dougga fluid composition, of which the Abiod reservoir is assumed to be main producing zone. To date only surface gas sample was obtained during the Well Dougga-1 test, which was terminated early.
- Differences seen between site and lab readings of CO_2, which have fundamental bearing on sales gas ratio, design basis for acid gas removal technology onshore and materials selection.
- Production estimates assume a range CGRs from 17.9 to 81.1 bbls/MMscf (Table 2-8). A conservative range of CGRs were adopted in the flow assurance work from 67.6 to 90.1 bbls/MMscf based on theoretical compositions prepared by AGR. CGR is a critical parameter for long, multi-phase tie-back flow and production assurance and onshore process plant sizing.

These uncertainties have been recognised by ADX and are expected to drive appraisal well testing regime.

The bulk of the facilities project definition to date is drawn from a concept study undertaken by TechnipFMC in 2017. The summary findings provided for this evaluation have been considered, along with a high-level review of the study reports, made available latterly.

3.3. Subsea Engineering Technical Risks

The overall subsea development concept is appropriately defined for this stage of the project. A number of key risks are highlighted below, most of which can be addressed once further data are available from the Dougga-Sud appraisal well.

3.3.1. Flow Assurance

The risks with respect to flow assurance fall into two categories: pressure support to ensure hydrocarbons reach the onshore process facility and hydrate formation. Both issues present significant uncertainties until results of the Dougga-Sud appraisal well are received but have been addressed as far as possible at this stage by the adoption of conservative input parameters (Section 3.2).

Production Flow Regime

Steady-state flow assurance work has been completed to date to confirm the feasibility of the subsea to shore option. Subsea to shore tie-backs are becoming established practice and the 45km distance appears feasible in this case, although the subsea compression assumptions noted above (Section 2.6.4) represent more emergent technology.

Numerous issues have yet to be analysed in detail, including multi-phase hydraulics, slug management and changing pressure and flows regimes as the field depletes (reservoir pressure depletion noted from circa 5250 to 1100 psi, although this latter pressure may well be insufficient to sustain flow, hence the plans for compression). This later aspect is particularly important when considering the constraints of a single export flowline.

Hydrate Management

Hydrate curve and associated management will be dependent on accuracy of compositional data however, the MEG technology proposed has been proven by analogues.

3.3.2. Compression Scenarios

Subsea Compression

Subsea compression is the current base case development assumption adopted by ADX. Only two commercial applications of subsea compression are in service: Statoil's Asgard and Gullfaks station facilities, which both came on stream in 2015. These examples followed Statoil's earlier Troll pilot project. Gas compression, whilst technically very attractive when compared to onshore compression, has represented the most challenging aspect of subsea processing for many years. Other applications such as subsea separators (Total Paz Flor) have been brought into service earlier.

Subsea compression of multi-phase fluids, particularly those with a high corrosive potential, requires sophisticated technology to separate, compress and recombine the wellstream product, all of which substantially increases the subsea power demand. The technical readiness of contemporary technologies for an application on Dougga is uncertain

Due to the complexity, high power demand and heavy reliance on rotating equipment, subsea compression would also represent a significant increase in subsea reliability, availability and integrity risks.

Offshore compression is the basis of ADX's planned development scheme and a successful offshore compression installation is as a necessary precondition of ERCE's resource assessment.

Subsea compression is an emerging technology and at present is not considered a proven technology. Should a subsea compression system not be feasible for the development of the Dougga discovery, or if a subsea compression system fails after installation, the resulting resources may be materially lower than the estimates presented in this evaluation report.

Onshore Compression

Onshore compression is regularly adopted to enhance recovery from gas fields. However, it is noted (Section 3.4) that the plant inlet pressure of 40 Bar is already low for the anticipated complex gas processing scheme. Booster compression onshore to drop this inlet from 40 to 20 Bar is considered readily achievable. It is recommended the benefits and trade-offs of onshore versus subsea compression are explored further in the next phases of the project.

Onshore compression has not been assumed in ERCE's base case production assessment.

3.3.3. Corrosion Management

The initial test data indicate the presence of high concentrations of CO_2 (circa 30 mol%) in the Dougga gas. Potential for H_2S has also been noted, with test data from Well Dougga-1 showing a H_2S content in the gas of about 50ppm.

A key aspect of the subsea facilities design has been to address the corrosive effects of wet gas export, since subsea flexibles constructed with corrosion resistant alloy (CRA) anyway. Mechanically lined pipe has been proposed, which is considered appropriate at this stage. Due to the corrosion design demands and lack of intervention options a comprehensive material testing programme will be required in the FEED/Define stage to confirm materials selection and optimise cost. This may extend the anticipated duration of FEED. Alternately adjustment mechanism would be required within EPCI scopes to allow for the latter.

3.3.4. Subsea Construction Considerations

Mechanically CRA lined steel pipe is proposed for the subsea export pipeline, which is considered appropriate given the corrosion challenges (above), line size and distance to shore. Installation will be via S-lay or reel-lay, J-lay will not be possible due the shallow water shore approach section. Welding CRA liners offshore whilst carefully managing the risk of weld contamination by the surrounding carbon steel carrier pipe is well established, but requires high levels of quality control. Note TechnipFMC proposed a large, capable S-lay / SURF construction vessel and have extensive experience with these technologies. Reel-lay, whilst perhaps on first inspection costlier, should be carefully considered due to its advantages of high quality control during onshore stalk construction. Modular spool bases and storage carousels have been effectively used in remote locations for projects in the Bass Strait, New Zealand and Norwegian Arctic.

Approximately 20km of the export pipeline lies in water depths of less than 20m and therefore requires trenching for protection, as well as dedicated nearshore / cross-shore working to install the conductor pipe for export pipeline and umbilical pull-in. It is considered likely the cost-effective method of trenching the pipeline and lowering the conduit pipe will be jetting. These tools are particularly susceptible to localized carbonate concretions which are common in North African and other hot climate coastal zones. These problematic soil conditions are difficult to identify with standard site survey tools and therefore specialist approaches require evaluation during planning of the site survey to reduce undue trenching risk.

ADX envisage subsea Christmas trees being installed by the SURF construction vessel, and that this represents a beneficial risk mitigating approach. Whilst this is certainly possible, the project is at a very early stage and therefore significantly more definition in field layout, drilling/construction sequencing and costs are required before any efficiencies such an approach may afford can be realized.

3.3.5. CALM Buoy for Condensate Offloading

This concept is considered robust technically and cost estimates appear reasonable for the CALM buoy elements.

3.4. Onshore Facilities

The Facilities IM accurately describes the Onshore Processing Plant (OPP) as highly complex, with large connected rotating equipment, a complex gas processing train, high specification CO_2 removal and associated high power demand. As with subsea facilities above, all aspects of the onshore process scheme require further assessment and optimization upon receipt of appraisal data.

Onshore facilities have numerous challenges:

- **The acid gas removal scheme:** this would be considered a world's first in stepping down from high input CO_2 loads at 30% mol% to a demanding export specification of 0.5 mol%. Such units are used for removal of high fraction inlet CO_2 elsewhere in the world, but those familiar to ERCE are stepping down to 15 mol% or 8 mol% sales specification. There may, therefore, be a need for two stage membrane separation.
- **CO_2 sequestration and onshore water disposal:** has been assumed. A candidate field 10km from the OPP has been identified, but access, disposal permits and technical work to ascertain the most appropriate disposal zone and its feasibility / capacity have yet to be completed.

- **High power load of 38 MW:** will require high fuel gas consumption. ERCE have made a preliminary estimate based on the proposed facilities which suggests at least 9 MMscf/d for base power. TechnipFMC calculated 7 MMscf/d, which has been adopted for determining sales gas volumes. Future compression, on or offshore as well as associated expanded utilities will add further demand.
- **Slug catcher sizing:** will need to be revisited due to uncertainty on CGR and formation water / GWC.

ADX have noted the interest shown by technology partners and opportunities for development of the OPP using modular units. Such approaches are considered ideal for facilities of this size and there are many analogues across the region. This does not remove the need for a substantial onshore facility to be established and sufficient allowance made in cost estimates for a main contractor to take responsibility for OPP integration. It is also understood ADX have received significant interest from technology providers who may be willing to lease and operate their components of the facility. As with the construction phase, this may be a suitable solution for complex elements of the plant but will need to operate within a wider Operations and Maintenance (O&M) organization.

Commissioning has been noted as an area where ADX hope to employ a streamlined approach. Whilst this can be achieved, focussed effort, including early engagement will be required early in FEED to ensure realistic integration and commissioning plans can be developed within the planned construction timeline.

3.5. Wells and Drilling

Well Dougga-1, the initial exploration well, gathered insufficient data to conclude an investment case for a full-field development, the objectives of the planned appraisal well are to demonstrate the productivity of the formations and to gather high integrity fluid data. A drilling rig has been contracted by ADX with a planned mobilisation in late 2018.

ADX energy have used AWES, an independent well engineering consultant, to undertake a review of the conceptual well design and also develop a deterministic view of the development well costs (DRILEX). This sought to re-evaluate the original AGR/TRACS estimates of 2008 on the basis more competitive cost rates combined with efficiencies in well execution. This has resulted in a reduction in appraisal well cost estimates from US$29MM to US$24MM, but more significantly a reduction in development well costs.

3.5.1. Wells and Completion Conceptual Design

Overall the well design concepts adopted are considered suitable. Further refinement will be required once fluid compositions are better understood.

3.5.1.1. Appraisal Well

The appraisal well is planned as a vertical well and casing design is standard, with a cemented 7” liner across the target formations. In terms of accessing a fracture network alternative completion schemes could be assessed to increase the likelihood of success. Commentary has been provided above on the production implications of this approach (Section 2.6.1). The well is planned as an appraisal-keeper and suitable re-completion plans included in the Development wells campaign.

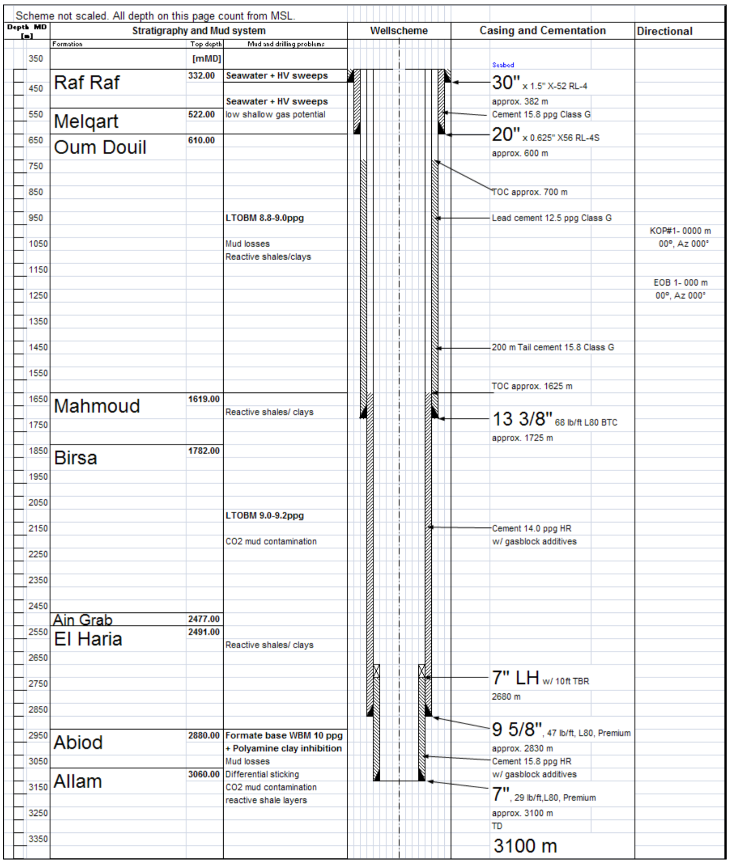

Figure 3.3: Dougga Conceptual Appraisal Well Schematic

The appraisal well is planned to be drilled in late 2018. ERCE have been informed Rig contracts are in place, although the term of these commitments has not been verified. The GlobeTrotterII drillship has been contracted at zero cost for mob/demob. It would appear that the rig is "ready stacked" having completed a campaign in Bulgaria in late 2017.

It has been stated in the Development Concept IM that "*produced water predictions are coarse and water chemistry is unknown*". It is stated that an objective of the appraisal well to gather pertinent data of the water to support and de-risk the development plan. However, on review of the detailed appraisal drilling and testing objectives (Section 12.1 of the Development Concept IM and Dougga Appraisal Well Programme) water production and water chemistry it is not stated as an objective. Due to the importance of formation water chemistry to long-term field planning it is recommended the objective of sampling is retained and costs increased accordingly.

AWES have recommended contingency string materials and equipment. These items will be necessary for robust execution of the well.

3.5.1.2. Development Wells

Five production wells are planned to be drilled in batch mode, at which time the subsea manifolds and umbilicals laid to hook-up with the manifolds. Wells will have horizontal Christmas trees (x-trees), which are intended to be installed by the subsea construction vessel. Completions will also be batch installed, using the rig. The suspended appraisal well is planned to be converted to a production well.

Wells are to be drilled to circa 3,100 mTVDSS with less than 1,000 m step-out from the surface location. Well designs and equipment ratings fall within 10,000 psi and 120 deg C for modelling. Lower completion across the reservoirs will be 7” casing, cemented and perforated. Upper completion will 4 ½” monobore tubing. It is planned to acid stimulate the wells.

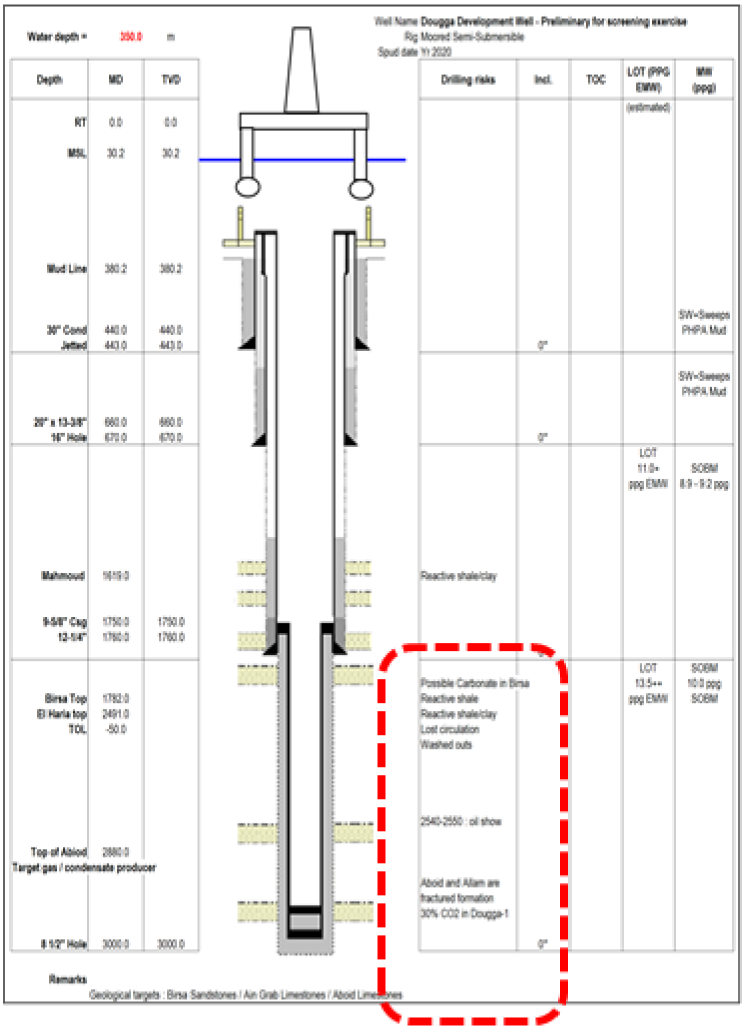

Figure 3.4: Dougga Conceptual “slim” Development Well Schematic

Development well design concept is for a “slim” well development, this means that the well is slimmed down one casing size (replacing 20” with 13 3/8” swaged back to 20” string). When compared to the appraisal well this means the last section of the hole extends from the 9 5/8” casing shoe at circa 1,760 m to TD at circa 3,000 m.

The 8 ½" reservoir section is circa 1,300 m long and has a number of potential drilling issues identified, (reactive shales, washouts, lost circulation zones, fractured formations, high CO2 zones), as highlighted above. There is a good focus on optimizing the well design, but relatively little evidence presented of de-risking the drilling operation. Correspondingly it is noted the conceptual program presented carries limited contingency. At this stage in the project and given the design concept it is recommended that the wells should carry higher levels of contingency and cost in relation to these identified potential drilling issues.

3.5.1.3. CO2 Injection Wells

The reference case for Dougga assumes two simple onshore CO_2 disposal wells.

3.6. Development Schedule

The proposed project schedule post-FID is appropriate. However, the 6-9 months allowance from completion of the appraisal well to FID (Figure 3.5) and thereby commitment to main contractors is considered unrealistic. Key tasks during this pre-FID period, some of which need to be undertaken in series to minimise re-work, include:

- Substantial subsurface update and modelling work to evaluate data gathered from Well Dougga-Sud;
- Potentially re-visiting the fields development concept if fluid properties are different of feasibility study assumptions or market conditions suggest advantages perceived today are no longer valid;
- Scoping, tendering and selecting a FEED consultant. This time may be reduced if key providers undertake their own FEED work in order to finalise commercial offers, but this potentially reduces competitive flexibility;
- Significant technical verification work of the entire development scheme to allow realistic pricing by contractors;
- Initially revisiting the EOI exercise, then scoping, tendering and contract negotiations with multiple main contractors. Again, potentially reduced by pre-selection of main partners;
- Securing finance;
- Regulatory approvals (not reviewed).

ERCE consider a more realistic schedule to be 18 months from completion of the appraisal well to FID, provided sufficient Owner's project management is deployed, thereby delaying 1st gas to early 2022. This represents a suggested correction to the schedule.

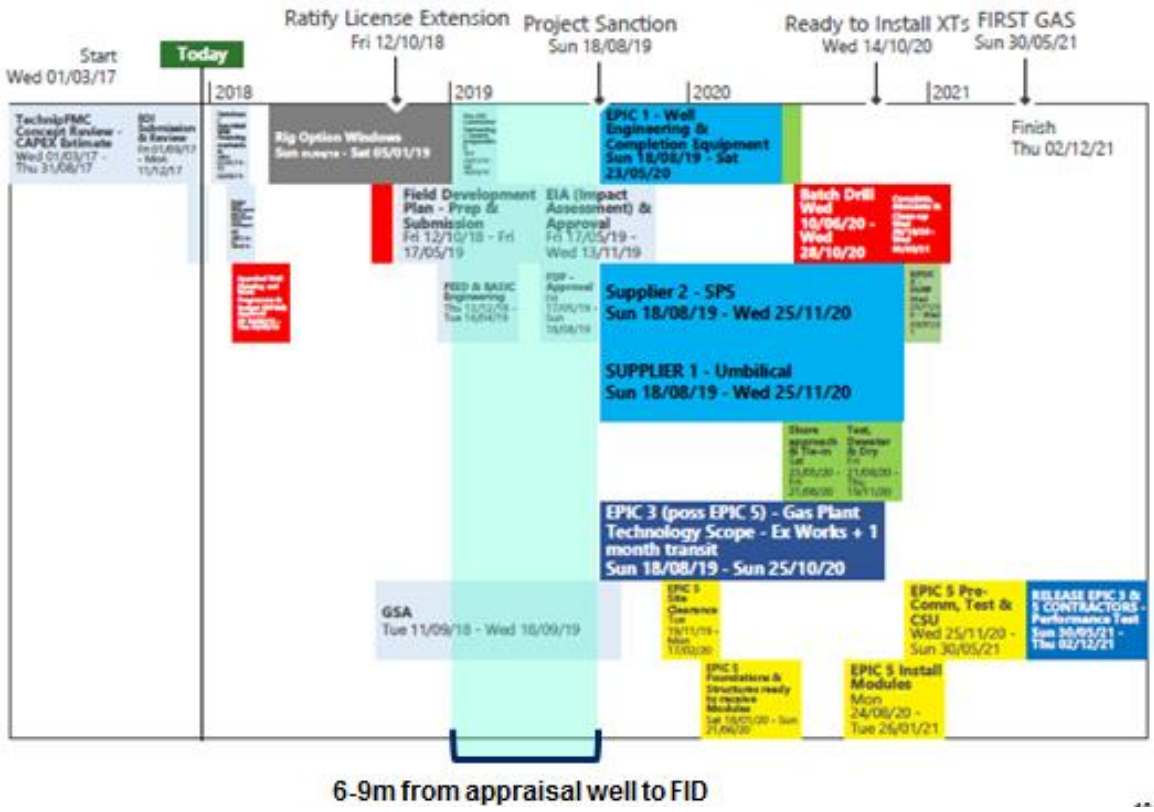

Figure 3.5: Project Schedule Summary

4. Dougga SW Prospect

4.1. Prospect Description

The Dougga SW prospect is located on the border of the Kerkouane PSC some 7 km southwest of Well Dougga-1, in a water depth of 330 m (Figure 4.1). Approximately 41% of the prospect is located within the Kerkouane PSC, in which ADX holds a 100% working interest. The prospect is seen as analogous to the Dougga discovery, of which a detailed evaluation can be found in Section 2 of this report.

The Dougga SW prospect is covered in part by the 2010 3D seismic data, with the remainder covered by several 2D seismic lines. The same reservoirs that are present in the Dougga discovery are targets in Dougga SW. These are the Campanian to Early Maastrichtian Abiod (matrix and fractures) and Cenomanian Fahdene (fractures only).

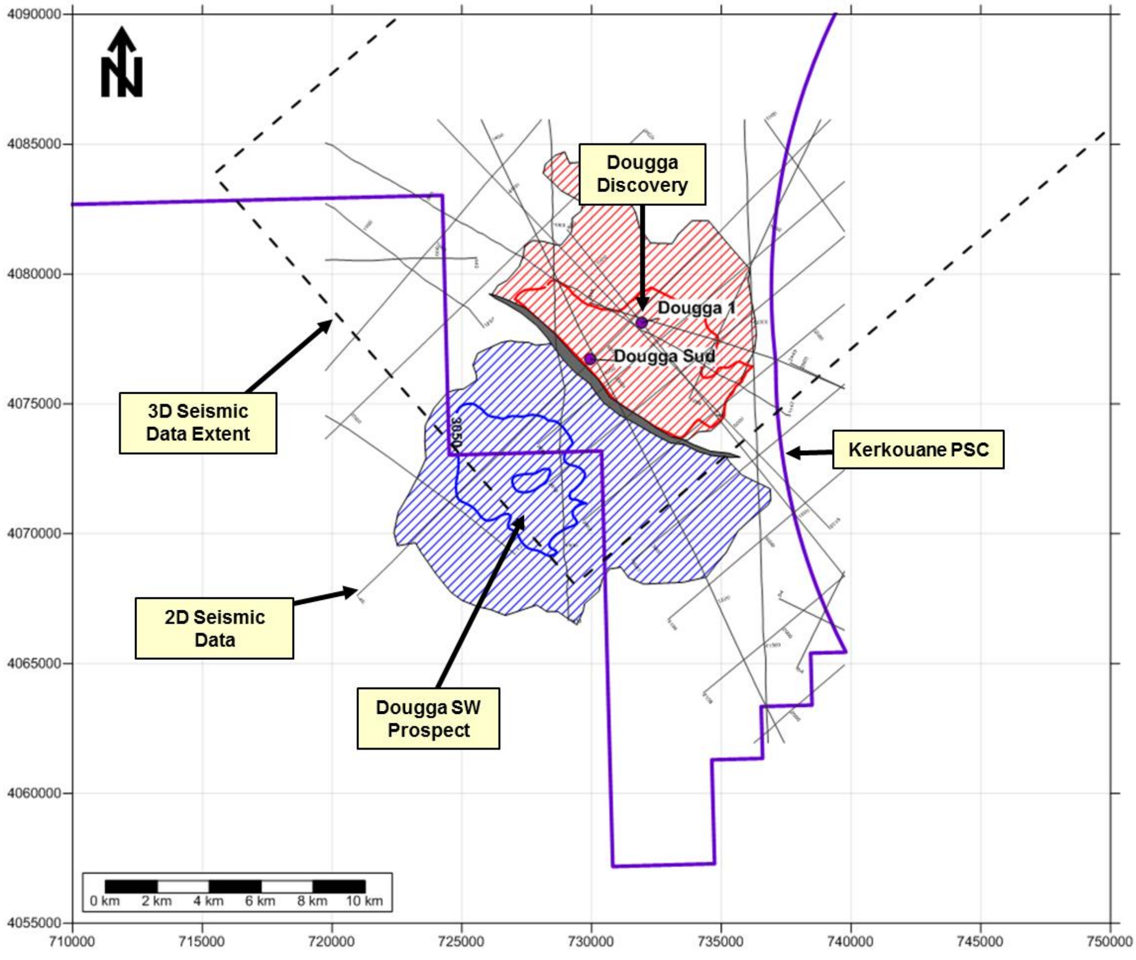

Figure 4.1: Location map of the Dougga SW prospect, Kerkouane PSC

4.2. Geophysical Aspects

The 2010 3D seismic dataset extends southwest outside of the Kerkouane PSC but does not cover the entirety of the Dougga SW prospect. In order to create a structural closure, some mapping on 2D seismic lines is required. The 2D seismic coverage over the southwestern portion of the prospect is sparse and as such there is structural uncertainty and risk on the presence of a structural trap. This uncertainty is reduced in the low case, where the majority of the structure is mapped on the 3D seismic data. A composite 3D-2D NE-SW seismic line through Well Dougga-1 to the Dougga SW prospect is shown in Figure 4.2. ERCE has reviewed the 2D seismic lines and finds ADX's interpretation of the Abiod structure to be reasonable.

No surface has been mapped for the Fahdene reservoir but ERCE has assumed the same structure exists at this level. The 2D seismic data, unlike the 3D data, is not of sufficient vertical resolution to allow the mapping of a Top Fahdene seismic event.

The velocity model used over the Dougga discovery is a multi-layer model based on 3D stacking velocities. A review of this model can be found in Section 2.2.1 of this report. ADX has extrapolated the velocity model to cover the Dougga SW prospect using gridding algorithms. Given that part of the prospect is covered by the 3D seismic data and the overburden remains comparable towards the southwest, this approach is seen to be reasonable and we have accepted ADX's Abiod depth structure map.

One of the key uncertainties for the Dougga SW prospect is reservoir thickness. In Well Dougga-1 the Abiod reservoir has a gross thickness of 66 m but is observed to thicken towards the southwest on seismic data. This thickening trend is expected to continue across the Dougga SW prospect. No base reservoir surface has been mapped on the seismic data and instead, isopachs are used to create a range of base reservoir surfaces.

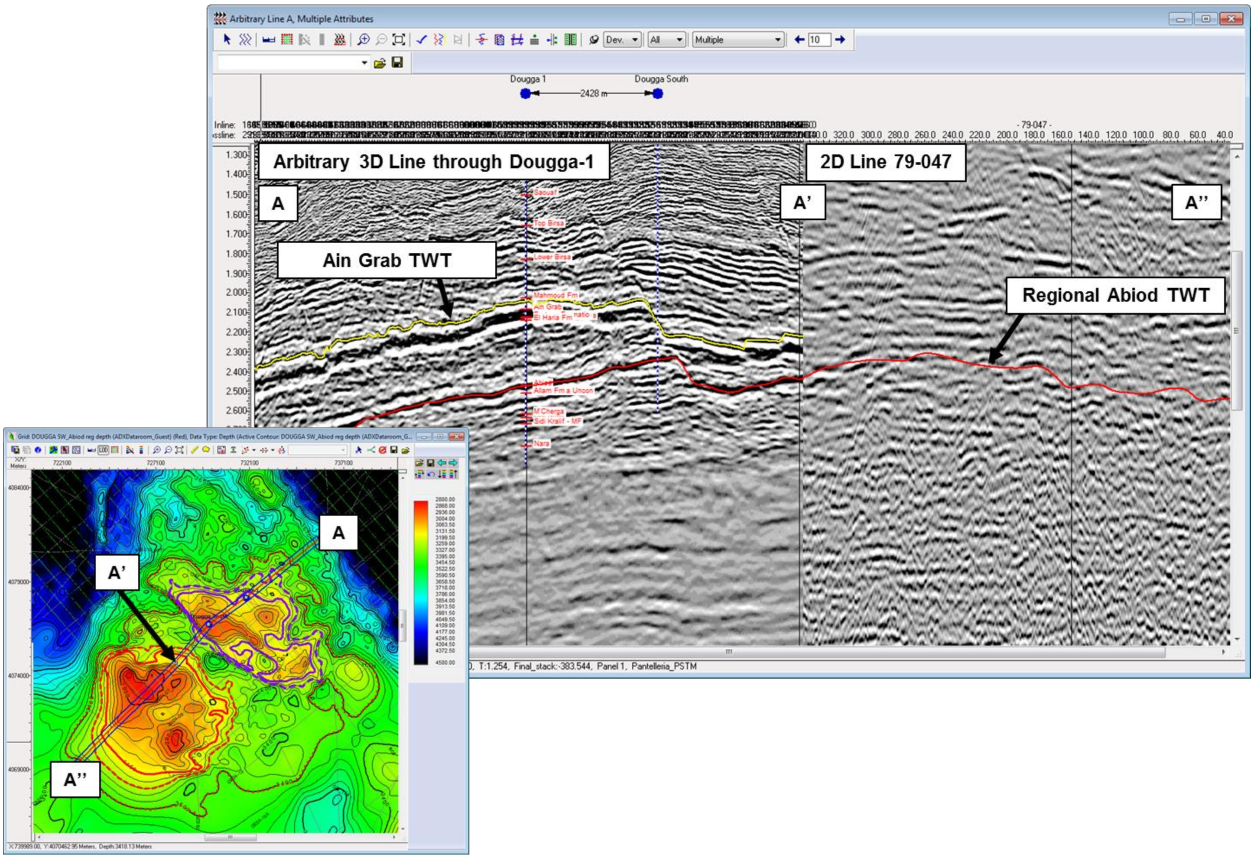

Figure 4.2: Composite seismic line through Well Dougga-1 and the Dougga SW prospect

4.3. Geological Evaluation

The main reservoir targets in the Dougga SW prospect are the Abiod (matrix and fractures) and Fahdene (fractures only) limestones. A detailed discussion on these reservoirs can be found in Section 2.3 of this report.

4.4. Hydrocarbons Initially in Place (HIIP)

We have calculated HIIP probabilistically and a range of GRV has been estimated. Our low case GRV model for the Abiod matrix uses ADX's top Abiod depth structure map and assumes a closing contour at 3,050 mTVDSS. This contour was selected as the resulting area is almost entirely covered by the 3D seismic dataset. A gross Abiod reservoir thickness of 60 m is used to create a base Abiod surface (Figure 4.3). This thickness considers the possibility that the reservoir is comparable to that found in Well Dougga-1, despite seismic data suggesting a southwestern thickening. The resulting GRV is considered to be a minimum case and is used as a P99 value in our definition of a log-normal distribution. In our low case, 38% of the GRV is located within the Kerkouane PSC.

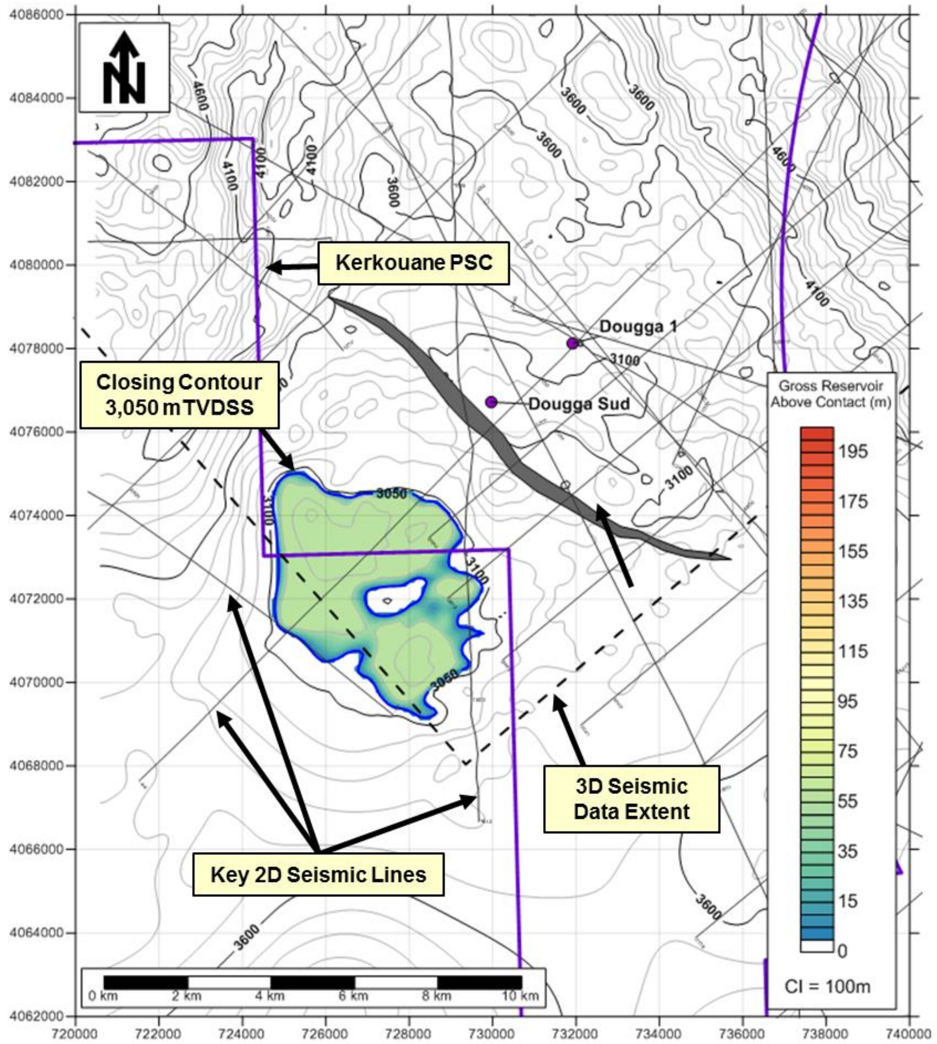

Figure 4.3: Low case gross reservoir above closing contour (3,050 mTVDSS)

Our high case Abiod matrix GRV uses the same top Abiod depth structure map and the same closing contour as used by ADX, 3,400 mTVDSS. This is the structural spill point assuming fill up to the NW-SE oriented normal fault separating the prospect from the Dougga discovery. It is possible that the Dougga and Dougga SW structures share this spill point as a common contact, creating a combined 4-way dip closure with a fault offsetting the two individual structures. A gross Abiod reservoir thickness of 200 m is used to create a base Abiod surface (Figure 4.4). This thickness is based on the observed thickening on seismic data. The resulting GRV is considered to be a maximum case and is used as a P1 value in our definition of a log-normal distribution. In our high case, 44% of the GRV is located within the Kerkouane PSC.

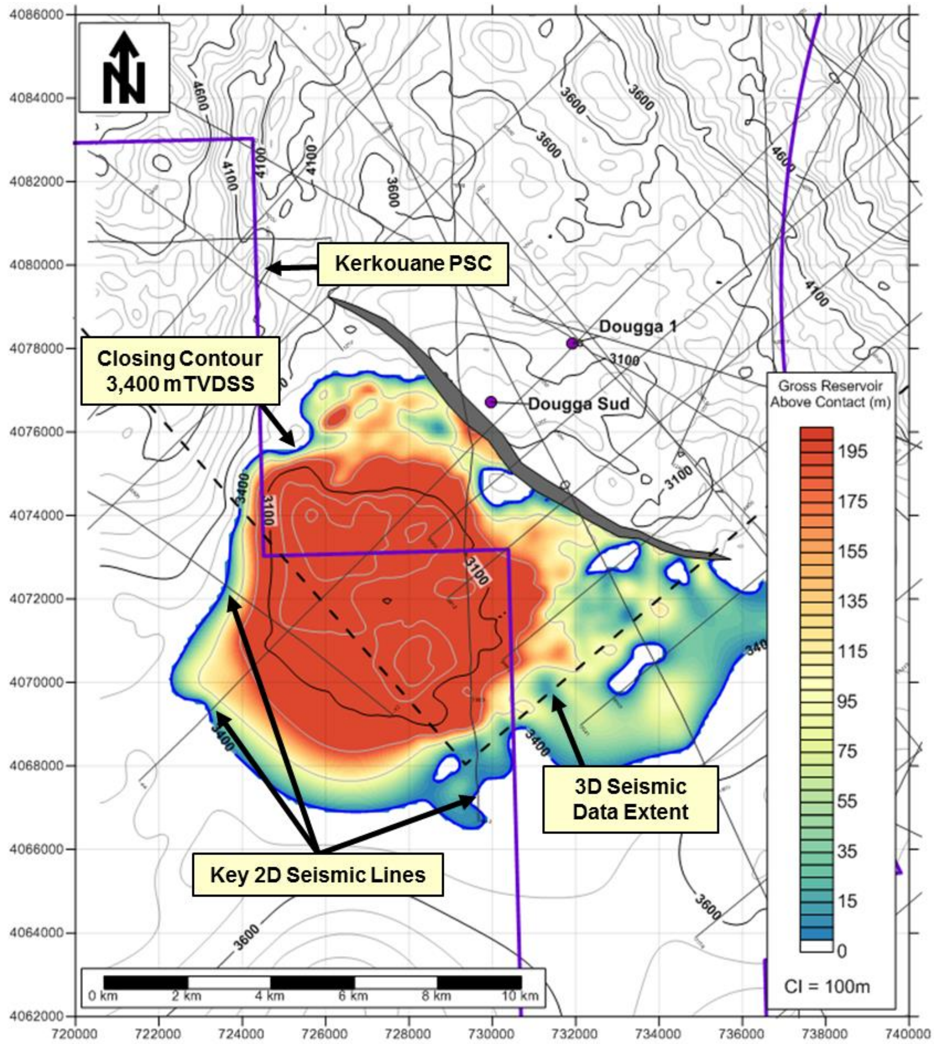

Figure 4.4: High case gross reservoir above closing contour (3,400 mTVDSS)

We have estimated the GRV for the Abiod and Fahdene fractures together, using the top Abiod depth structure map and a range of gross reservoir thicknesses. For the Abiod fractures we assume the same low and high case gross reservoir thickness (60 m and 200 m). The thickness of the Fahdene in Well Dougga-1 is 225 m and we have used a low and high case gross reservoir thickness of 100 m and 300 m respectively. This is added to the Abiod isopach to give a total low and high case gross reservoir thickness of 160 m and 500 m respectively. As with the Abiod matrix, the resulting GRVs are considered to be the minimum and maximum and are used as P99 and P1 values to define a log-normal distribution.

Given its proximity to the Dougga discovery we have assumed that the NTG, porosity (matrix and fractures) and gas saturation distributions are the same (see Section 2.5). We have also used the same range in GEF given that the two are at similar depths and would be expected to have similar, if not the same, hydrocarbon compositions.

A summary of the volumetric inputs used is shown in Table 4-1 and Table 4-2. The probabilistic GIIP results are shown for the whole structure and the on-PSC structure in Table 4-3, where

'Gross GIIP' refers to the whole structure including volumes outside of the Kerkouane PSC and 'On PSC' refers to volumes inside the PSC only (assuming 41% of the volume is within the PSC).

Table 4-1: Input GRV, NTG and PHI distributions, Dougga SW prospect

Reservoir	GRV (MMm3)			NTG (frac)			PHI (frac)		
	Log-Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10
Abiod Matrix	1597	3224	6515	0.50	0.70	0.90	0.070	0.085	0.100
Abiod & Fahdene Fractures	2762	5319	10213	1.00	1.00	1.00	0.00020	0.00118	0.00700

Table 4-2: Input Sg and GEF distributions, Dougga SW prospect

Reservoir	Sg (frac)			GEF (scf/rcf)		
	Normal			Normal		
	P90	P50	P10	P90	P50	P10
Abiod Matrix	0.50	0.60	0.70	208	227	250
Abiod & Fahdene Fractures	0.93	0.95	0.97	208	227	250

Table 4-3: Probabilistic GIIP results, Dougga SW prospect

Reservoir	Gross GIIP (Bscf)				On PSC GIIP (Bscf)			
	P90	P50	P10	Mean	P90	P50	P10	Mean
Abiod Matrix	391	878	1962	1067	161	361	806	438
Abiod & Fahdene Fractures	39	149	386	190	16	61	159	78
Total (Probabilistic Sum)	**543**	**1076**	**2179**	**1256**	**223**	**442**	**896**	**516**

4.5. Prospective Resources

We have estimated the recoverable gas and condensate resources for the Dougga SW using the same range in CGR and recovery factor as was used in our evaluation of the Dougga discovery (Table 4-4). These are applied probabilistically to the GIIP distribution. It should be noted that these estimates of recoverable gas do not account for any anticipated surface losses and include any potential inert gases.

Table 4-4: CGR and recovery factor distributions, Dougga SW Prospect

Prospect	CGR (bbl/MMscf)			RF (frac)		
	Normal			Normal		
	P90	P50	P10	P90	P50	P10
Dougga SW	21.59	41.1	81.1	0.63	0.71	0.79

The probabilistic results for the prospective gas and condensate resources are shown for the whole structure and the on-PSC structure in Table 4-5 and Table 4-6 respectively.

Table 4-5: Unrisked gas Prospective Resources, Dougga SW prospect

Reservoir	Gross Unrisked Gas Resource (Bscf)				On PSC Unrisked Gas Resource (Bscf)			
	Low	Best	High	Mean	Low	Best	High	Mean
Abiod Matrix	274	622	1400	757	112	256	575	311
Abiod & Fahdene Fractures	28	106	274	135	11	43	113	55
Total (Probabilistic Sum)	**383**	**762**	**1550**	**892**	**157**	**313**	**637**	**366**

Table 4-6: Unrisked condensate Prospective Resources, Dougga SW prospect

Reservoir	Gross Unrisked Cond. Resource (MMbbl)				On PSC Unrisked Cond. Resource (MMbbl)			
	Low	Best	High	Mean	Low	Best	High	Mean
Abiod Matrix	9.7	30.1	79.8	39.5	4.0	12.4	32.8	16.2
Abiod & Fahdene Fractures	1.0	5.0	15.4	7.0	0.4	2.0	6.3	2.9
Total (Probabilistic Sum)	**15.0**	**37.5**	**88.0**	**46.5**	**6.2**	**15.4**	**36.1**	**19.1**

4.6. Risking

We have reviewed ADX's assessment of the geological chance of success (COS) and find it to be reasonable. The COS is considered to be 30%. However, due to differences in the reservoir parameter ranges, we believe that the main risk for the Dougga SW prospect is the presence of a structural trap.

Given that Well Dougga-1 encountered effective reservoir to the northeast, and because we carry a lower range in porosity (matrix and fracture) than ADX, we see the risk of reservoir presence and efficacy to be lower.

We believe that, due to the requirement of 2D seismic data to define a structural closure to the southwest, there is an associated risk on the presence of such a trap. Furthermore, the sparseness of the 2D lines poses a risk that between them a closure does not exist.

5. Appendix 1: SPE PRMS

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum Resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum Resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardise the definitions of petroleum Resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum Resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilised in Resources definitions (2005). SPE also published standards for estimating and auditing Reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of Resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources”; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum Resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS, can be viewed at http://www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf

Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total Company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project’s economic feasibility, its productive life, and its related cash flows.

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term “Resources” as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth’s crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional” or “unconventional.”

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE Resources classification system. The system defines the major recoverable Resources classes:

Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

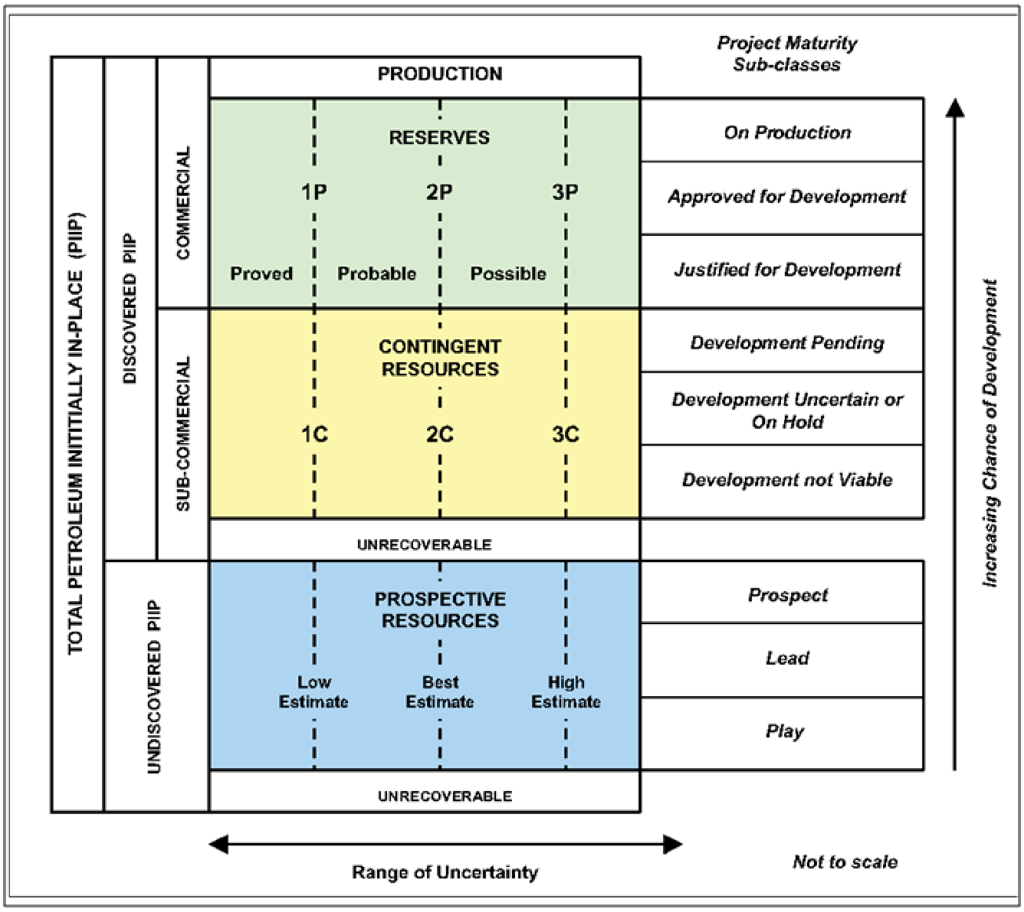

Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Development”, that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the Resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total Resources”).

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

Discovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

the area delineated by drilling and defined by fluid contacts, if any, and

adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (see “2001 Supplemental Guidelines,” Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

Undiscovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognised that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

• There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

• There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

• There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Evaluators may assess recoverable quantities and categorise results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see “2001 Supplemental Guidelines,” Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as

1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete Resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classifications of projects and categorization of estimated quantities recovered by each project.

6. Appendix 2: Nomenclature

AI	acoustic impedance
°API	degrees API, a measure of oil density
AVO	amplitude variation with offset
Bbl	barrels
Bscf	thousands of millions of standard cubic feet
Bo	oil shrinkage factor or formation volume factor, in rb/stb
boe	barrels of oil equivalent, where 6000 scf of gas = 1 bbl of oil
°C	degrees Celsius
CGR	condensate gas ratio
CPP	central processing platform
1C	Low Estimate Contingent Resource
2C	Best Estimate Contingent Resource
3C	High Estimate Contingent Resource
cm	centimeter
cp	centipoises
CPI	Computer Processed Information log
CRA	corrosion resistant alloy
3D	three dimensional
DST	drillstem test
Eg	gas expansion factor
EPT	a Shell Internal Audit Process conducted in 2006
°F	degrees Fahrenheit
FDP	field development plan
FEED	front end engineering and design
ft	feet
ftss	feet subsea
FTHP	flowing tubing head pressure
FSO	floating storage and offloading vessel
FVF	formation volume factor
FWS	full wellstream

g	gram
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact
GOR	gas oil ratio
GR	Gamma Ray
GRV	gross rock volume
GSA	gas sales agreement
GWC	gas water contact
Kair	air permeability
kh	permeability thickness
km	kilometers
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	metres
M MM	thousands and millions respectively
MBAL	material balance computer programme
md or mD	millidarcy
MD	measure depth
MDT	modular formation dynamic tester
mgal	milligal where 1 mGal is one thousandth of 1cm/s2
MSL	Mean Sea Level
m/s	metres per second
mss	metres subsea
NaCl	sodium chloride
N/G	net to gross ratio
Np	cumulative oil production
ODP	outline development plan
ODT	oil down to
OWC	oil water contact
Por or Phi	porosity

Proved	Proved, as defined in Appendix 1
Probable	Probable, as defined in Appendix 1
Possible	Possible, as defined in Appendix 1
PSC	Production Sharing Contract
PSDM	pre stack depth migration
1P or P	Proved
2P or P+P	Proved + Probable
3P or P+P+P	Proved + Probable +Possible
P99	99 per cent probability
P90	90 per cent probability = Proved
P50	50 per cent probability = Proved + Probable
P10	10 per cent probability = Proved + Probable + Possible
P1	one per cent probability
P0	zero per cent probability
psia	pounds per square inch absolute
psig	pounds per square inch gauge
ppm	parts per million
pu	porosity unit
PVT	pressure, volume, temperature
P/Z	pressure divided by gas deviation factor (material balance)
rcf	cubic feet at reservoir conditions
res bbl	reservoir barrels
Rs	solution gas oil ratio
Rt	true resistivity
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
scfd	standard cubic feet per day
Sg	gas saturation
So	oil saturation
Soi	initial oil saturation
Sor	residual oil saturation
stb	a standard barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit

stb/d	standard barrels per day
STOIIP	stock tank oil initially in place
ss or TVDSS	true vertical depth sub-sea
Sw	water saturation
TAD	tender assisted drilling
TD	total depth
TVD	true vertical depth
TOC	total organic carbon
twt	two way time
WF	water-flood
WGR	water gas ratio
WHP	wellhead platform
WOR	water oil ratio
WUT	water up to
Vshale	shale volume