Nostrum Oil & Gas PLC

Competent Person's Report

Resource Date 01 January 2024

Stepnoy Leopard, Republic of Kazakhstan

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REV	DATE	DESCRIPTION	ISSUED	CHECKED	APPROVED	CLIENT
04	23/07/2024	Final For Issuance	LL/JF/MG	AS	JF	AK
03	22/07/2024	Draft of full report	LL/JF/MG	AS	JF	AK
02	16/07/2024	Final Executive Summary issued	LL/JF/MG	AS	JF	AK
01	01/05/2024	Draft issued for comments	LL/JF/MG	AS	JF	

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Nostrum Oil & Gas PLC
20 Eastbourne Terrace
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30th June 2024

To Whom it may concern

Competent Person's Report on Nostrum Oil & Gas PLC's Interest in the Stepnoy Leopard Fields, Kazakhstan

Xodus Group Limited ("Xodus") has provided an independent evaluation of the Reserves and Resources expected from Nostrum Oil & Gas PLC's interest in the Kamenskoe-Teplovskoe-Tokarevskoe area in the West Kazakhstan Region (the "Stepnoy Leopard" fields), in accordance with the Petroleum Resources Management System ("PRMS") (2018) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers ("SPE") and reviewed and jointly sponsored by the World Petroleum Council ("WPC"), the American Association of Petroleum Geologists ("AAPG") and the Society of Petroleum Evaluation Engineers ("SPEE").

Throughout this report, volumes are expressed as gross Stock Tank Oil Initially In Place ("STOIIP") or Gas Initially In Place ("GIIP") volumes. These can be considered "discovered petroleum initially in place". Recoverable volumes are expressed as gross and net Stock Tank Barrels ("STB") for Reserves, and Contingent Resources.

In conducting this review, we have used information and interpretations supplied by Nostrum Oil & Gas PLC ("Nostrum" or the "Company"), as well as information in the public domain. The information supplied is operator information, geological, geophysical, petrophysical, well logs and other data along with various technical reports as at the Effective Date of 1st July 2024. We have reviewed this information and modified assumptions where we considered this to be appropriate. No site visit has been undertaken.

We have used standard geological and engineering techniques accepted by the petroleum industry in estimating the volumes. These techniques rely on geoscientific interpretation and judgement; hence the volumes of Reserves and Resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of volumes may increase or decrease in future if more data becomes available and/or there are changes to the technical interpretation. As far as Xodus is aware there are no special factors that would affect the operation of the assets and which would require additional information for their proper appraisal.

Xodus is not aware of any significant matters arising from this evaluation that are not covered by the report which might be of a material nature with respect to the assessment. Xodus also confirms that where any information contained in the report has been sourced from a third party (other than the Company), such information has been accurately reproduced and, so far as we are aware and are able to ascertain from the information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

Yours faithfully,

Jonathan Fuller
For and on behalf of Xodus Group Ltd.

1 EXECUTIVE SUMMARY

At the request of Nostrum Oil & Gas PLC ("Nostrum" or the "Company"), Xodus Group Limited ("Xodus") has prepared a Competent Person's Report ("CPR") on the Kamensko-Teplovsko-Tokarevskoe area in the West Kazakhstan Region (the "Stepnoy Leopard" fields), owned by Nostrum's subsidiary, Positive Invest LLC ("PI"). The resultant net working interest in Stepnoy Leopard under current licence terms is 80%, which is the basis for this CPR. This CPR only pertains to the interest in Stepnoy Leopard, and not the other blocks and fields in which Nostrum has an interest.

The effective resource date is 01 January 2024, which means that the costs, discounting and NPV calculations in the economic model are referenced to this date. The date of the evaluation is 01 July 2024.

Reserves and Resources

A summary of the Reserves associated with Stepnoy Leopard, on both a gross and working interest basis, are shown in Table 1-1. The Reserves are an arithmetic summation of the economically recoverable resources for five different fields in Stepnoy Leopard, including the four eastern Artinskian fields and the Kamenskoye field in the west of the area.

	Gross			Working Interest (80%)		
	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE
Sales Gas (BCF)	408.54	620.93	779.36	326.83	496.74	623.49
Condensate & Oil (MMSTB)	16.96	26.62	34.27	13.58	21.30	27.42
LPG (kTonnes)	414.47	629.93	790.66	331.58	503.94	632.53

Table 1-1 Table of Reserves; Gross and Working Interest to Nostrum as of 1st January 2024

Notes
1. *Oil and Condensate are presented as one line item as the development wells initially produce commingled from the oil and gas legs in the eastern fields*
2. *Reserves are presented on a gross and on a working interest basis post deductions for fuel*
3. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied*
4. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates.*
5. *Reserves are stated after the application of an economic cut-off*
6. *Full definitions of the Reserves categories can be found in Appendix B*

A summary of the Contingent Resources associated with Stepnoy Leopard, on both a gross and working interest basis, are shown in Table 1-2. The Contingent Resources are an arithmetic summation of the technically recoverable resources in the three western Artinskian fields, together with the volumes from the four eastern Artinskian fields and the Kamenskoye field that could be produced after the licence expiry on the 31st December 2044.

	CATEGORY	Gross			Working Interest (80%)		
		1C	2C	3C	1C	2C	3C
Raw Gas (BCF)	Development Unclarified	190.88	361.76	776.76	152.71	289.41	621.41
Condensate & Oil (MMSTB)	Development Unclarified	2.86	7.05	16.38	2.29	5.64	13.10

Table 1-2 Table of technically recoverable Contingent Resources; Gross and Working Interest to Nostrum as of 1st January 2024

Notes
1. *Condensate and oil measured at standard conditions*
2. *Contingent Resources are presented on a gross and on a working interest basis post deductions for fuel*
3. *Contingent Resources must be discovered*
4. *Under PRMS, Development Unclarified means there is no defined development project and volumes are technically recoverable. This includes volumes that could be produced after the licence expiry if a suitable development plan was in place.*
5. *1C, 2C and 3C denote the low, best and high estimate scenario of Contingent Resources respectively as defined under PRMS*
6. *Full definitions of the Contingent Resources categories can be found in Appendix B*

Economic Evaluation

The Net Present Values (NPV) of future cash flows derived from the exploitation of all of the Reserves in Stepnoy Leopard are presented in Table 1-3. The values stated are net to Nostrum's interest after deduction of Royalties and Taxes. The values are based on a combination of prices for the different products with an assumption about how much is exported and how much sold domestically. The export price for oil and condensate is based on a Brent Oil Forward Curve sourced from Intercontinental Exchange Futures EU in May 2024. Beyond the end of the forward curve (from 2030) the oil price has been inflated at 2% per year. The domestic price for gas and condensate is set by Ministry of Energy in Kazakhstan. Details of all pricing assumptions are provided in the main part of this report.

It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets.

NET TO NOSTRUM (80% WI)			
	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE
NPV10 ($USMM)	120.3	220.4	267.9
IRR (NET)	26.8%	33.8%	34.3%

Table 1-3 Net Present Value of Stepnoy Leopard Reserves as of 1st January 2024

No site visit was undertaken during the engagement.

Xodus believes that the figures in this report accurately reflect the potential on the asset, given current knowledge.

Professional Qualifications

Xodus Group Limited is an independent, international energy consultancy. Established in 2005, the company has 500+ subsurface and surface focused personnel spread across offices in Aberdeen, Anglesey, Cairo, Dubai, Edinburgh, Glasgow, London, Orkney, Oslo, Houston and Perth.

The Advisory division specialises in petroleum reservoir engineering, geology and geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system.

Except for the provision of professional services on a fee basis, Xodus has no commercial arrangement with any person or company involved in the interest that is the subject of this report.

Jonathan (Jon) Fuller was responsible for supervising this evaluation. A Reservoir Engineer, with a strong commercial experience he has 30 years of international experience in both International Oil Companies, large Service Companies and Consultancy organisations. Over the last 16 years he has been the technical and project management lead on Reserves and Resources evaluations in M&A, Competent Person's Reports, and expert opinion linked to bank and institutional investment (both debt and equity). He is a recognised Competent Person according to London Stock Exchange Guidance note for Mining, Oil and Gas Companies of June 2009.

Jon has an M.Eng (Hons) in Engineering Science from Oxford University, a Master's Degree in Petroleum Engineering from Heriot-Watt, and an MBA from INSEAD. He is a member of the Society of Petroleum Engineers (SPE), and the Association of International Energy Negotiators (AIEN).

2 INTRODUCTION

On the 17th July 2023, Nostrum announced that it had completed the acquisition of an 80% interest in Positive Invest LLP ("Positive Invest"), which holds the subsoil use right to the contract No. 25 for estimation, development and production of hydrocarbons for the area "Kamenskoe" and the development area "Kamensko-Teplovsko-Tokarevskoe" (the "Stepnoy Leopard" fields) in the West Kazakhstan region of the Republic of Kazakhstan dated 3 March 1995 (as amended from time to time, the "Positive Invest Contract"). The Positive Invest Contract is currently due to expire in December 2044.

The Stepnoy Leopard fields are located between approximately 60km and 120km west of Nostrum's Chinarevskoye field and within 10km of its oil and condensate loading terminal at Beles. Stepnoy Leopard consists of two licences with eight fields where hydrocarbons have been discovered. In excess of one hundred wells across the eight fields were drilled during the Soviet era. The fields have not yet been developed.

Nostrum has appraised two of the wells in the easternmost field (Teplovskoye) in early 2024 and subsequently revised the field development plan that had been submitted to the Republic of Kazakhstan's Ministry of Energy (the "Ministry of Energy") in December 2020 under the Positive Invest Contract. The main parts of the development plan have not changed and are based on a tieback to Nostrum's existing infrastructure at the Chinarevskoye field.

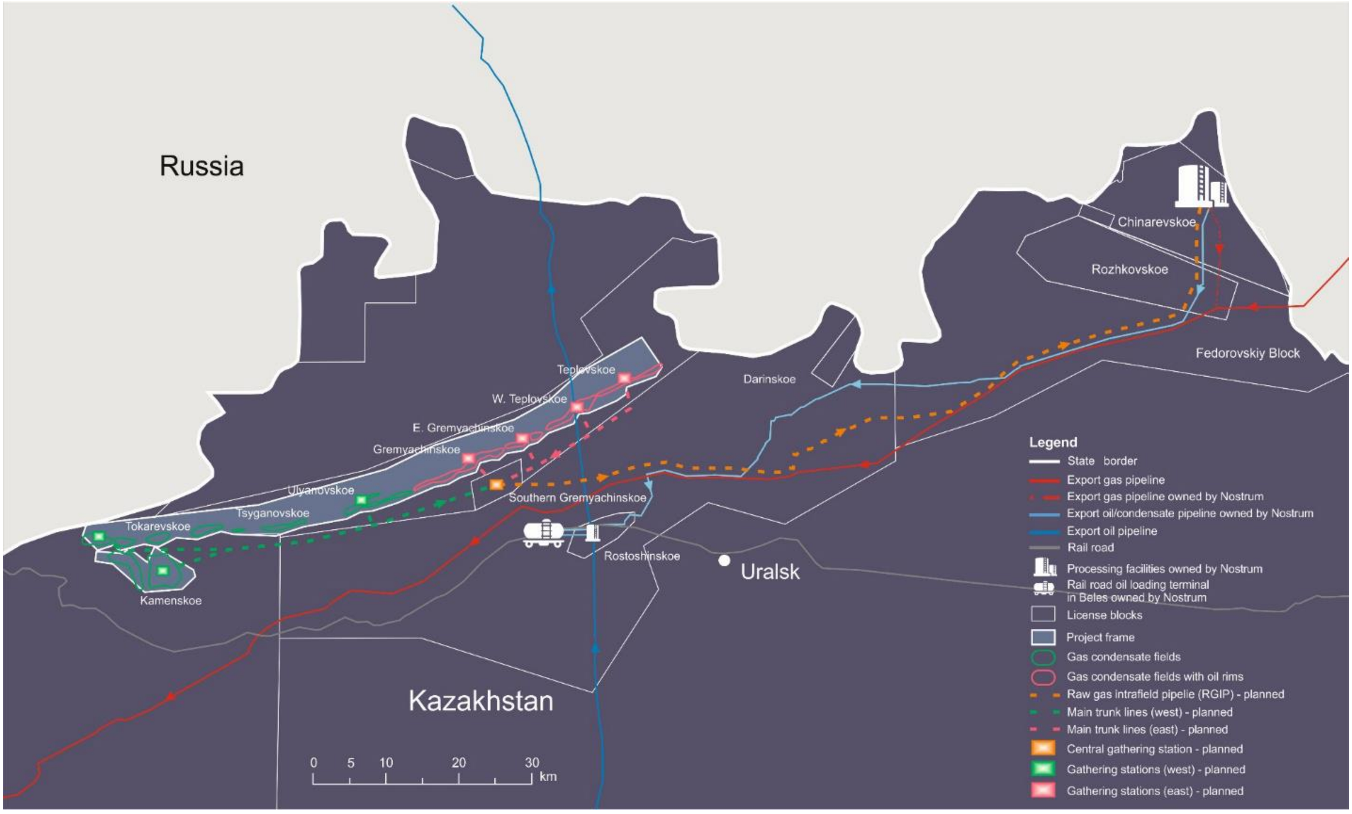


Figure 2-1 Location of Stepnoy Leopard and other Nostrum assets

2.1 History of work on Stepnoy Leopard

The Stepnoy Leopard area was originally explored and appraised during the Soviet period. The seven fields of the Teplovsko-Tokarevskoye group were discovered in the 1970s. By 1991 a total of 106 vertical wells, slanted wells and sidetracks had been drilled in these fields. The Kamenskoye field was discovered in 1986. A total of 15 wells were drilled on the Kamenskoye field, 3 of which are located outside the licence area.

The first official report on Reserves for the Stepnoy Leopard group of fields was done by Uralskneftegazgeologya in 1991. This included only the fields with hydrocarbons in the Artinskian and Filippovski reservoirs. An updated report on Reserves was written by Uralskneftegazgeologya in 1996 to include the Kamenskoye field, containing hydrocarbons in the Kalinovski reservoir.

In preparation for submitting the first version of field development plans in 2019, Nostrum commissioned PM Lucas to undertake comprehensive new analysis and interpretation of all Stepnoy Leopard data in 2018. This was updated in 2020 for a revision to the development plans. During 2019 there were also reviews from other consultants and a CPR by Ryder Scott. Subsequent to 2020, Nostrum continued to work on refining the subsurface interpretations with the support of local contractors such NIPIneftegas and Reservoir Evaluation Service ("RES"), and international consultancies.

The reports from the work from 1991 up to the present day have been provided to Xodus, although some of them are only in the Russian language. In addition, Xodus has received the information below in italics from Nostrum and, on the basis of this information and other documents, it accepts that there is an approved field development plan for Stepnoy Leopard.

In May 2019, the subsoil user contract for the Kamenskoye, Teplovsko-Tokarevskoye group of fields (KTTGF) was transferred to Positive Invest LLP (the Company) through the signing of Amendment No. 2. In August 2019, the Company submitted field development plans (FDP) to the Ministry of Energy (MoE) and received their approval.

In 2020, the company decided to correct the FDPs by postponing the date of first production to a later year. As a result, the corresponding Amendment to the FDPs (AFDPs) was introduced with the start of production in 2026 and submitted to the MoE for approval. On November 26, 2020, the CKR Board decided to approve the amendments on the condition that the date of first production was brought forward by one year from the 2026 to 2025 (CKR protocols: Teplovskoye № 04 -0/8709 as of 08.12.2020, West Teplovskoye № 04-0/8708 as of 08.12.2020, East Gremyachinskoye № 04-0/8693 as of 07.12.2020, Gremyachinskoye № 04-0/8707 as of 08.12.2020, Ulyanovskoye № 04-0/7970 as of 20.11.2020, Tsyganovskoye № 04-0/8710 as of 08.12.2020, Tokarevskoye № 04-0/7968 as of 20.11.2020, and Kamenskoye № 04-0/8711 as of 08.12.2020). The corrected amendments had to be submitted within 30 days.

The company and the project institute made the necessary changes to the AFDPs and submitted the corrected documents on December 25, 2020 (cover letter № 78-69-81 as of 25.12.20).

Since 2020 the company has been submitting official financial reports to the authorities using the indicators of the corrected version of the AFDPs. The government authorities have accepted the company's reports to date without any qualifications or comments.

On May 31, 2024, the company asked the MoE for official written confirmation that the corrected AFDPs as of Dec 2020 had been received. This confirmation letter was received in June 2024 and provided to Xodus.

3 GEOLOGY AND GEOPHYSICS

3.1 Regional Geology

The Pre-Caspian Basin is one of the oldest basins in the world, and is located in Russia, Kazakhstan, and the Northern part of the Caspian Sea. The basin spans about 500,000 km^2 and reaches depths of 20 km below the Earth's surface. The Pre-Caspian Basin is one of the largest hydrocarbon provinces in the world and exploration began in the early twentieth century. The fields discussed in this CPR are located on the northern side of the basin, west of Karachaganak, and are fully within the borders of the Republic of Kazakhstan (Figure 3-1).

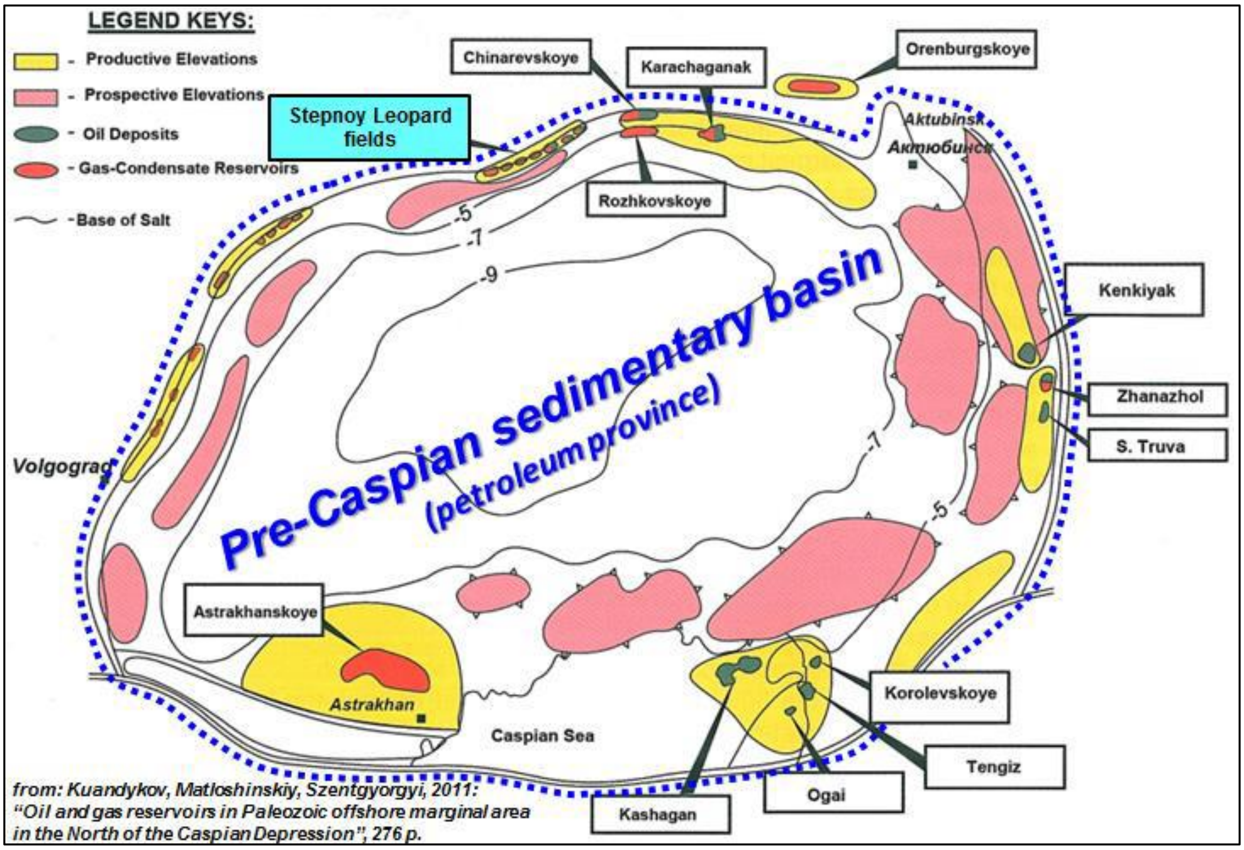


Figure 3-1 Location of the Stepnoy Leopard fields within the Pre-Caspian sedimentary basin (From Stepnoy Leopard Field Feasibility Study, 745-FOR-INTPRM-00050, 2018)

The Pre-Caspian basin is estimated to have formed between the Palaeozoic and Cenozoic times. It overlies two large pre-Permian depressions. During the Ordovician, sediments began filling the basin followed by a thick layer of salt that is 4-5 km thick. The salt was buried by more sediments, creating large salt domes underneath the surface. The oldest, deepest sediments are Devonian.

The stratigraphic record of the Pre-Caspian basin is defined by three megasequences:

- Subsalt: Containing sediments from the Devonian through to Lower Permian (Artinskian stage).
  In this megasequence there were four distinctive carbonate cycles which were prolific in carbonate production and built distinctive carbonate shelves with several contemporaneous isolated carbonate platforms. These cycles were ceased either by periods of sharp eustatic level fall and/or by regional tectonic activities. During these periods, clastic deposition predominated on exposed shelves, slopes, and basin floor. The Moscovian-Artinskian carbonate complex is a result of the latest major subsalt cycle of carbonate deposition within the basin and rocks within shelf rim are the reservoir rocks for main hydrocarbon pools of the Stepnoy Leopard fields.

- The salt megasequence: The Kungurian stage of the Lower Permian.
  In this sequence, eustatic sea level fall resulted in high evaporation within the basin and precipitation of thick evaporate sediments starting with the Filippovski anhydrite (the lower Kungurian) and ending with Sosnovski halite-terrigenous formation (the uppermost Kazanian formation). Prolific Filippovski anhydrite deposition was interrupted by several episodic sea ingressions which re-established conditions for carbonates and chemical deposition. Further evaporation during Kungurian times resulted in precipitation of remarkably thick Irenian halite suite, which is composed of up to eleven evaporative cycles, each starting with carbonate-sulphate beds followed by thick halite formations. This halite suite is regarded as a regional seal to hydrocarbon migration from subsalt to suprasalt sediments. Clastic depositions (mostly clays) were laid down during evaporative draw-down episodes. Filippovski dolomite beds represent reservoir rocks for subordinate hydrocarbon pools in the Stepnoy Leopard fields.
  Sea transgression in the beginning of the Kazanian stage ceased clastic-evaporite deposition and established normal marine conditions that produced Kalinovski carbonates, which are the main reservoir in the Kamenskoye field, which are compartmentalized and fractured by strong halokinetic forces. Ongoing evaporation conditions derived thick evaporites of hydrochemical origin and Sosnovski formation, which act as seal rocks to the Kalinovski hydrocarbon bearing reservoir.

- Suprasalt: From the Upper Permian to the present.

Hydrocarbons have been found in the subsalt Artinskian and Filippovski (Lower Permian) in the seven of the Stepnoy Leopard fields, and in the Upper Permian Kalinovski unit that forms part of the salt megasequence in the Kamenskoye field (Figure 3-2).

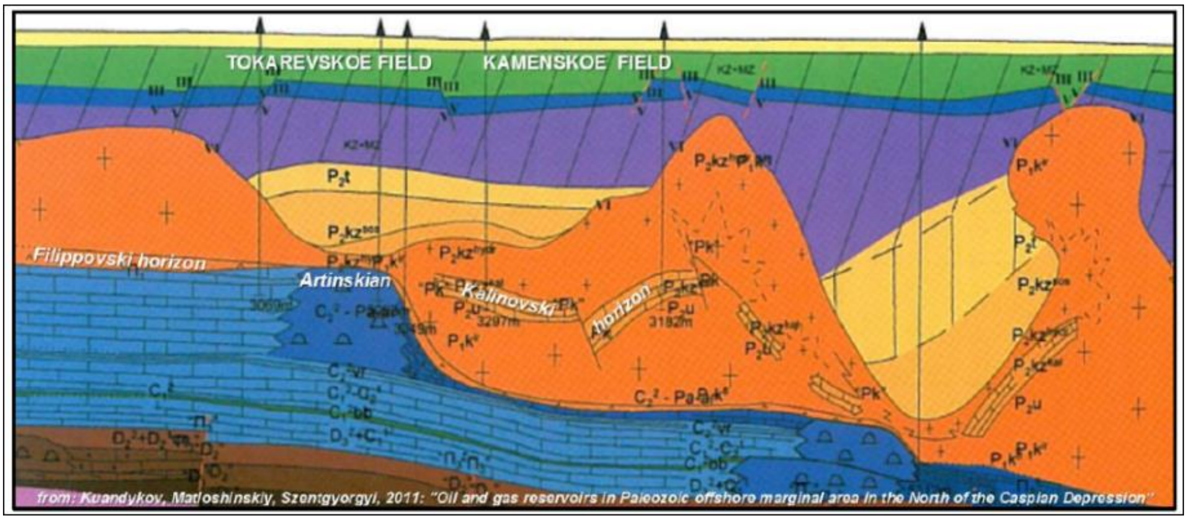


Figure 3-2 Geological cross-section through reservoir horizons (From Stepnoy Leopard Field Feasibility Study, 745-FOR-INTPRM-00050, 2018)

Chronostratigraphic Chart for Permian Time								
System/ Period	**Series/ Epoch**		International		**Pre-Caspian Basin**			
			Stage/ Age	Age (Ma), bottom	**Stage/ Age**		**Horizon/ Suite**	
Permian	**Upper**	**Lopingian**	Changhsingian	254	**Tatarian**	**P_2t**		
			Wuchiapingian	260	**Kazanian**	**P_2kz**	**Sosnovski**	**P_2ss**
		Guadalupian	Captian	266			**Hydrochemical**	**P_2hd**
			Wordian	268			**Kalinovski**	**P_2kl**
			Roadian	271	**Ufimian**	**P_2u**		
	Lower	**Cisuralian**	Kungurian	276	**Kungurian**	**P_1k**	**Irensky**	**P_1ir**
							Filippovski	**P_1fl**
			Artinskian	284	**Artinskian**	**P_1ar**		
			Sakmarian	295	**Sakmarian**	**P_1s**		
			Asselian	299	**Asselian**	**P_1a**		
	reservoir horizons of interest to Stepnoy Leopard Project							

Figure 3-3 Permian Chronostratigraphy with highlighted reservoirs (From Stepnoy Leopard Field Feasibility Study, 745-FOR-INTPRM-00050, 2018)

3.2 Reservoir Geology

The Stepnoy Leopard group includes seven gas-condensate-oil fields forming a chain of hydrocarbon accumalations in Permian-age Artinskian and Filippovski reservoirs. The fields from the South-West to the North-East (Figure 3-4) are:

- Tokarevskoye
- Tsyganovskoye
- Ulyanovskoye
- Gremyachinskoye
- East Gremyachinskoye
- West Teplovskoye
- Teplovskoye

The Kamenskoye Field, located South of the Tokarevskoye Field, is the only gas-condensate bearing reservoir found in the upper Permian Kalinovski formation (Figure 3-4) in Stepnoy Leopard.

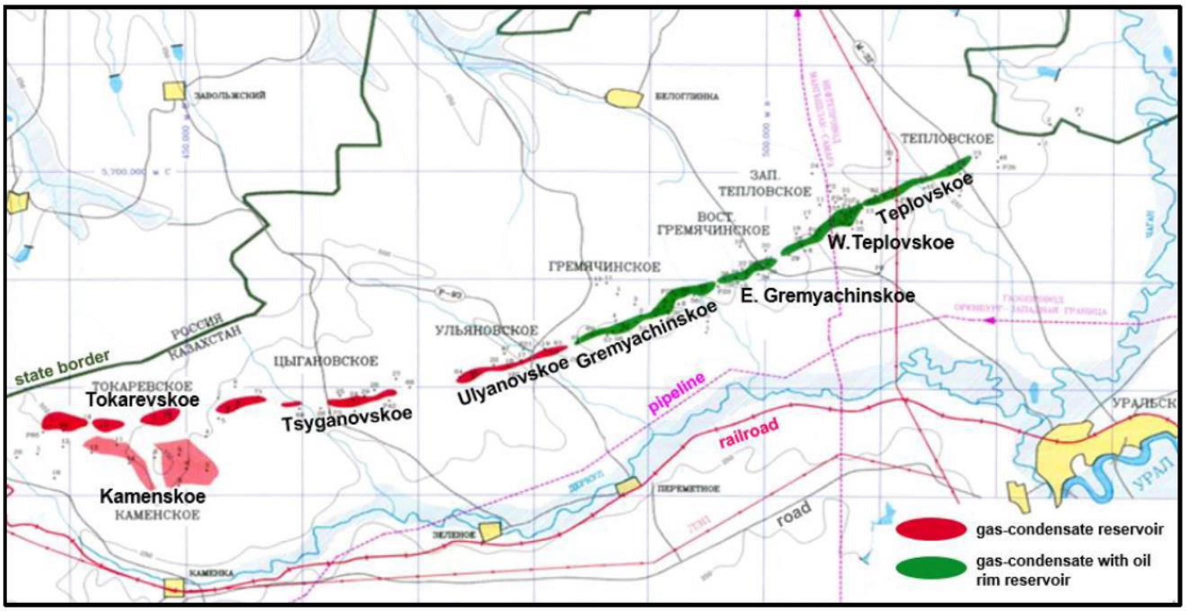


Figure 3-4 The hydrocarbon fields of interest in Stepnoy Leopard (From Stepnoy Leopard Field Feasibility Study, 745-FOR-INTPRM-00050, 2018)

The first complete evaluation of the fields was undertaken in 1991, and a reserves report was produced (in Russian). Since then, there have been a number of other studies (updates to the reserves report, studies by PM Lucas and others). Derived values used for volumetric calculations have changed over time as new wells have been drilled, new data has been made available and with the application of new interpretation techniques, however the fundamental concepts of reservoir deposition and diagenesis have not changed.

Artinskian Reservoir: contains the majority of the Petroleum Initially-In-Place.

- Reservoir: Massive reefal carbonates (dolomites and limestones). It was deposited in the final stage of Moscovian-Artinskian carbonate cycle, which built a broad shelf along the northern part of the Pre-Caspian basin. These carbonates build a long chain of barrier reef, forming a rim along the shelf edge. Shelf rims rises from 150m to almost 300m above shelf table. Reservoir rocks are fractured, which greatly contribute to their permeability. In general, vugs and fractures are unevenly distributed and the factors controlling the distribution are unknown.
- Seal: Filippovski anhydrite rock
- Hydrocarbon saturation: gas, condensate and oil (only in the Eastern fields)
- Trap: Stratigraphic traps (barrier reefs developed along shelf edge)

Filippovski Reservoir: contains the subordinate Petroleum Initially-In-Place

- Reservoir: Dolomite formations within occasionally dolomitic limestones. Gradually thickens away from the Artinskian shelf rim to the North-West and reaches 250 m within the boundary of the license block. It was deposited within a broad shelf lagoon in the North-West of the Artinskian barrier rim.
- Seal: Kungurian salt and intra Filippovski anhydrite.
- Hydrocarbon saturation: gas-condensate
- Trap: Stratigraphic traps (lithological pinch out of reservoir formations)

Note: Due to the small size and low chance of development, no volumes have been calculated by Nostrum or by Xodus for the Filippovski reservoir for the purposes of this CPR.

Kalinovski Reservoir: contains a proved hydrocarbon accumulation in the Kamenskoye Field

- Reservoir rocks: thick carbonate-clastic sequence developed between two evaporate formations (Lower Permian Kungurian). The clastic horizon is thin and at the bottom of the sequence.
- Seal: Evaporites of hydrochemical origin and Sosnovski formation.
- Hydrocarbon saturation: Gas-condensate
- Trap: Complex structural salt related trap (combination of salt and faults)

3.3 Seismic Interpretation

Database

The available seismic dataset consists of three separate 3D seismic cubes in the depth domain and a large number of 2D lines. These were provided to Xodus in a Petrel Project along with interpretation carried out by RES on behalf of Nostrum, based on the Kamensko-Teplovsko-Tokarevskoye (KTT) 3D seismic data (325 km^2), processed in 2019, the Melovaya 3D (129 km^2) processed in 2022 and 2D seismic lines (total length ~1588 km), processed in 2020. There is some uncertainty associated with the depth imaging of all data sets related to salt presence in the form of diapirs and walls in the area that can interfere with the velocity correction and depth migration. To complete the structural model of the area, previous interpretation by RES for the Darjinskaya and Rostoshinskaya areas was used together with information from all 128 drilled wells in the area. As can be seen from the seismic basemap in Figure 3-5, the 3D seismic data does not cover all of the field areas.

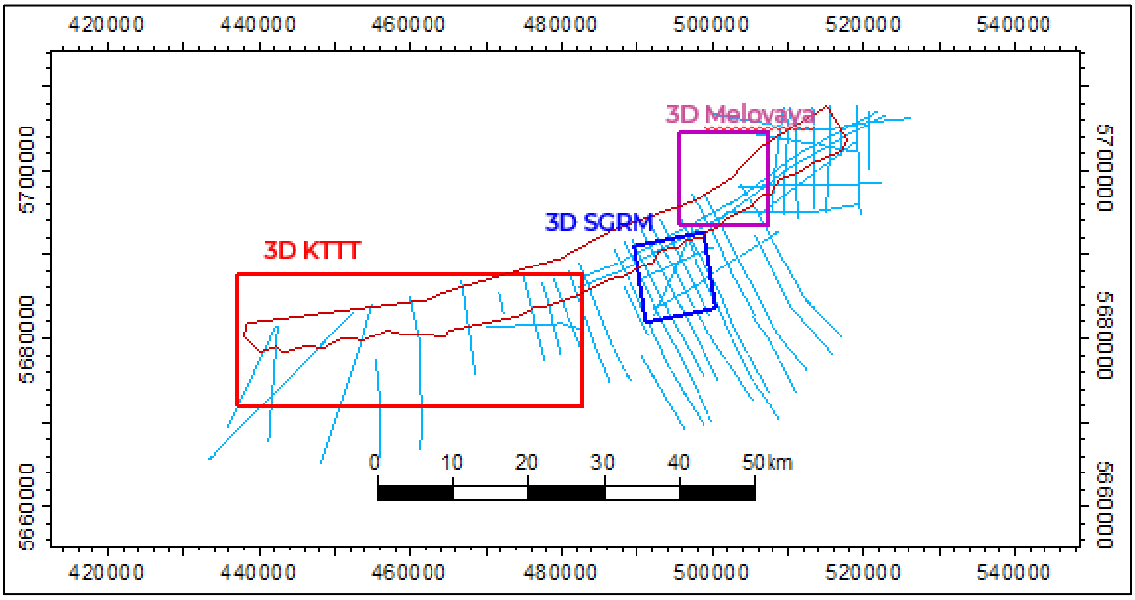


Figure 3-5 Basemap of locations of 3D and 2D seismic

Seismic Interpretation

The main objective of the interpretation of the 2D/3D seismic data by RES was structural mapping to enable 3D geological modelling and hydrocarbon in place volumes estimation. In general, seven seismic horizons were interpreted:

- III, Top Jurassic
- V, Top Triassic
- VI, Top Kungurian (Salt)
- P2kl, Top Kalinovski carbonates
- P1fl or S, Top Filippovski
- P1ar, Top of the Artinskian
- C2, Top near C2m

Structural maps and thickness maps of the main stratigraphic intervals were constructed over the entire area based on the results of the interpretation. The main reservoir horizons are: Artinskian (P1ar), Filippovski (S) and Kalinovski (P2kl).

Challenges and Uncertainties

In general, data quality is quite variable. The 2D data is often poor quality. The 3D data is good quality apart from at the reefs and in some areas below salt diapirs. The main issues and challenges for seismic interpretation are:

1. Seismic Mistie: This is related to the mismatch between different 2D and 3D seismic surveys, acquired at different times and with different parameters. These "artefacts" have to be corrected by using different mapping algorithms and ultimately increase uncertainty in the interpretation.

2. Seismic Well Tie: This is related to the correlation between well tops and seismic horizons of interest. The seismic data was provided in the depth domain, therefore, no seismic-well-tie SWT was necessary. However, we observed a major challenge for the interpretation in that the well tops for the main reservoirs Artinskian (P1ar) and Filippovski (S) were in different seismic events, especially along the reef margin. In areas away from the reef to the north and north-west, correlation was more consistent. This issue may have multiple causes, including uncertainty on well locations and trajectories in the older wells, limited used of well data during seismic processing, problems with the velocity model due to geological complexity and poor seismic resolution. During the interpretation and mapping, in areas of mismatch, the seismic data was used as a general trend while the well tops were used as hard data and maps were corrected to honour and tie to them.

3. Seismic Coverage: Not all fields are covered by the same type of data. In general, fields interpreted with just scarce 2D data will have a major uncertainty compared to fields that are interpretated using 3D data. Fields Gremyachinskoye, East Gremyachinskoye and West Teplovskoye are covered by a combination of 3D seismic (Melovaya or SGRM) and 2D seismic, while the Teplovskoye field is covered just by 2D seismic data. The Kalinovski Field is fully covered by 3D KTTT seismic.

3.4 Petrophysics

3.4.1 Core Data

Core data is available in all fields with varying recovery and analysis data quality. The recovery is poor in the best reservoir sections where large open fractures and vugs are present, which is typical for carbonate formation coring practices. The recovered core was analysed by various research institutes in Russia and Kazakhstan during the early 1990s. Standard core analysis was complimented by the implementation of special techniques such as digital p microscopic photography and image based fracture evaluation, cube shaped sample luminescent photography after soaking in luminophore fluid, centrifuge and mercury injection pore size analysis.

These studies were documented in the initial Reserve evaluation submissions for Teplovskoye-Tokarevskoye group of fields (1991), Kamenskoye Field (1996) and the Core data report by VNIGNI (1990). PM Lucas Core studies review (745-CDA-SSE-2006, Nov 2018) summarised the data and conclusions from the previous report and converted the findings to international nomenclature and terminology.

3.4.2 Wireline Log Data

The log dataset within the fields of Stepnoy Leopard is represented by the vintage Soviet-style log data recorded on paper media and digitized to LAS format. The log suite is very typical for Soviet era data and is generally very limited and of variable quality both due to the acquisition system and tools limitation, and digitising artefacts.

The "Standard log" set recorded in all wells includes the SP, Calliper and the set of multi-spacing unfocused lateral, inverse lateral and normal resistivity logs. The focused Laterolog type resistivity data was acquired in the majority of the wells.

Nuclear logs are mostly limited to Gamma Ray (recorded in uR/h Soviet-style units and unitless (arbitrary normalised count rate) Neutron-Gamma uncompensated neutron measurement. The neutron log cannot be directly used in formation evaluation and requires pre-processing and conversion. The conversion was performed by Nostrum using commonly available tool specific charts approximations and two-point calibration based on the tight limestone zones and a washed-out interval readings. The approach used is consistent with industry practice for treating vintage uncalibrated neutron data.

Sonic log (mostly uncompensated modification of the tool) is commonly available in the dataset and is of reasonable quality except for heavily fractured or washed-out intervals.

Density log was not a common measurement in the Soviet era datasets due to tool availability problems, calibration issues of the old Soviet tools and safety concerns of running the radioactive source on the pad device prone to be stuck in the irregular borehole conditions common to the fractured carbonate environment. Density measurement was acquired in some wells in the Stepnoy Leopard fields (as per the PM Lucas report 745-WLI-PET-SSE-20014):

- Kamenskoye – 6 wells
- Tokarevskoye - 9 wells
- Tsyganovskoye - None
- Ulyanovskoye – 2 wells
- Gremyachinskoye – None

- East Gremyachinskoye – 3 Wells
- Teplovskoye – None

The density log digitised from the paper media is not recorded in density units and requires additional processing using the tool-specific chart and calibration coefficients. The calibration is not always available on the raw log prints and iterative calibration using the clean lithology homogeneous intervals were used by Nostrum to fine tune the processed bulk density log. The typical calibration point can be a halite or anhydrite interval where the porosity effect is minimal on the raw density reading and it can be calibrated to the value of matrix density in the known lithology.

The processed Density and Neutron logs plotted on the standard Neutron-Density Cross plot show reasonable grouping of points separating the salt-dominated interval and mixed carbonate section. The EGR-22 N-D cross plot is shown in Figure 3-6 below.

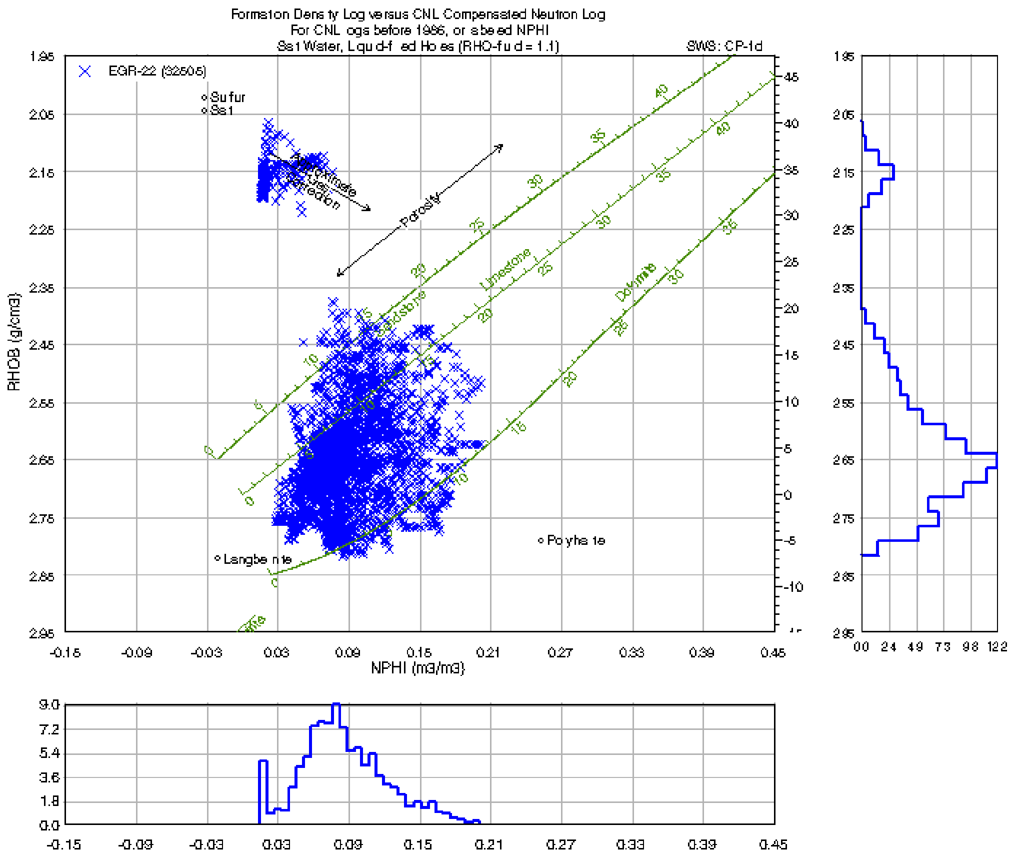


Figure 3-6 EGR-22 Neutron-Density cross plot

The typical full dataset, with the density log present, used for the interpretation methodology analysis was identified in well EGR-22 (East Gremyachinskoye field).

The evaluation methodology is covered in Sections 4.2, 5.2 and 6.2.

4 THE FOUR EASTERN ARTINSKIAN FIELDS

4.1 Seismic Data and Interpretation

The Artinskian horizon over the four eastern fields is highly variable and presents a challenge to interpret as a result of poor seismic resolution, a poor match between seismic and well data, and misties between 2D lines and 3D surveys (Figure 4-1). Wherever there was a poor seismic-well tie between the well tops and the seismic reflector, RES finalised the interpretation by matching horizons to well tops first and then following the seismic as much as possible. Examples of the Artinskian reefal fields are shown in dip seismic sections in Figure 4-2 and Figure 4-3 from both 2D to 3D seismic data. In some cases the final surface appears to cut across the seismic reflections in order to be able to tie the wells at the crest of the reef and those in the back reef or lagoon area. This appears to be unavoidable with the data available at present and the uncertainties associated with this have been captured to a reasonable degree.

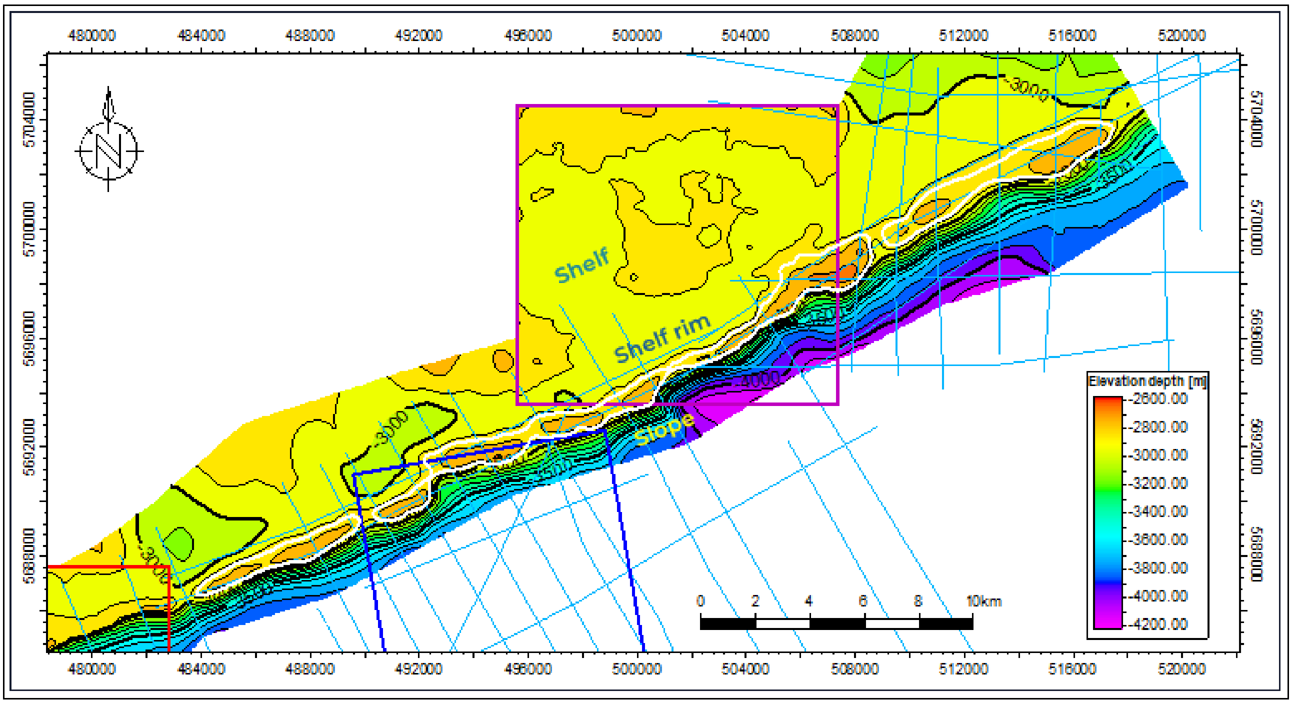


Figure 4-1 Structural Map of the Artinskian horizon (P1ar), CI=100m, 3D SGRM in blue, 3D Melovaya in Purple, 2D seismic lines in light blue.

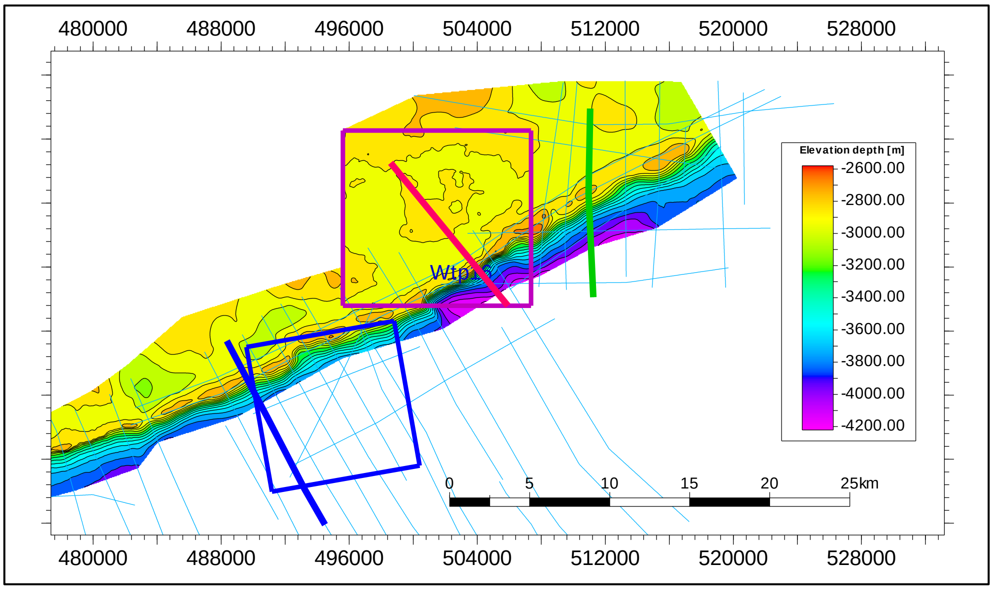


Figure 4-2 Artinskian Structural Map showing Dip-Seismic Section for the fields

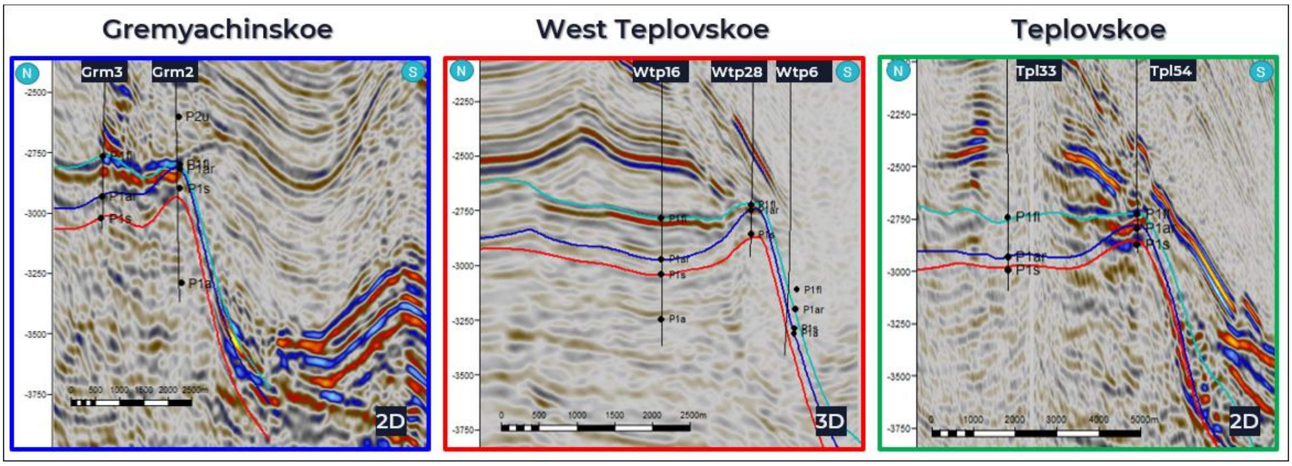


Figure 4-3 Dip Seismic Sections showing interpretation of the Artinskian (P1ar, dark blue), Filippovski (P1fl, green) and Sakmarian (P1S, red) in different fields

4.2 Petrophysics

4.2.1 Core Studies

An extensive (for the period) core analysis using the available technology at the time was performed on the core recovered from Artinskian intervals in 1990-1991 by various institutes in the USSR and the Republic of Kazakhstan.

Apart from routine porosity/permeability/bulk density measurements, digital photography analysis was employed for texture analysis and facies/Environment of Deposition (EOD) and pore structure classification.

The 1991 Report illustrates the sedimentary structures of various lithofacies with microscopic black and white photographs (Figure 4-4). The quality of the illustrations available for review is quite low after multiple printing/scanning runs but gives an idea of the variations in textural character of different lithofacies and characteristic textural features of different lithotypes and related EOD.

The main sedimentological lithotypes defined on core have been adopted by PML based on the 1991 report (Table 8.4 in 1991 – table 5.2 in PML Core review). The Soviet style terminology has been translated to Wilson and Dunham's classification and summarised in Table 5.1 of the PML core report and used for further geological analysis and conceptual model creation.

The 1991 Report has more EOD/Lithotype statistics in various tables (per field, per well etc.). But the general conclusions in both reports are consistent, as described below.

- Lateral and vertical distribution of lithofacies is certainly very complex and is a matter of significant uncertainty.
- No wellbore image data is available in SL fields, so no log-based reliable texture related lithotyping is possible.
- Conclusively, Artinskian carbonate reefs grew in a warm, shallow subtidal to intertidal marine environment of normal salinity.

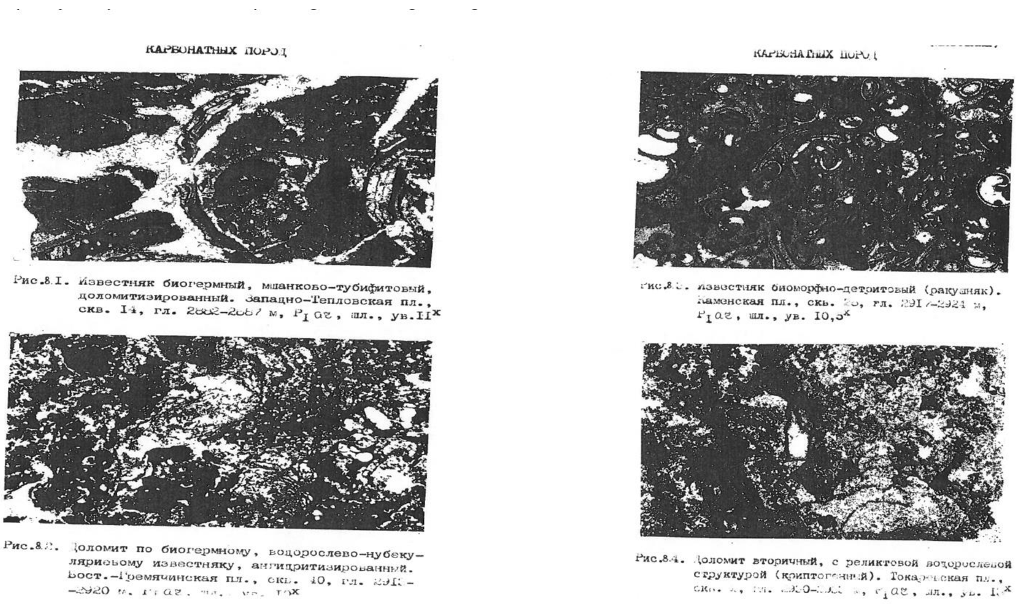


Figure 4-4 Photomicrographs from 1991 Reserves Report illustrating sedimentary structures

Lithology sections of the 1991 GKZ and PML Reports lead to very similar conclusions based on the available core data:

- Dolomites represent prevailing Artinskian hydrocarbon-bearing reservoir rocks: roughly two thirds of cored material. So, dolomitization (early and late diagenetic) is the most important process of rock alteration. Microscopic lab analyses revealed that late diagenetic dolomites prevail compared to early diagenetic ones. Primary dolomites appear mostly in back-reef domain in the uppermost part of the stratigraphic section.
- Anhydrite presence, connected to the dolomitization process, significant variations of anhydrite presence are noted.

Pore geometry and reservoir properties typing was performed in both 1991 and recent PM Lucas studies and led to similar classifications and conclusions. See PM Lucas report 745-CDA-GG-SSE-20006.

Based on the core description and digital photography analysis the main 6 types of pore geometries were defined (Figure 4-5):

1. Interparticle primary pores
2. Relict primary pores and vugs
3. Interparticle pores
4. Intercrystalline pores
5. Leaching vugs
6. Open Fractures (not present in core due to recovery problems)

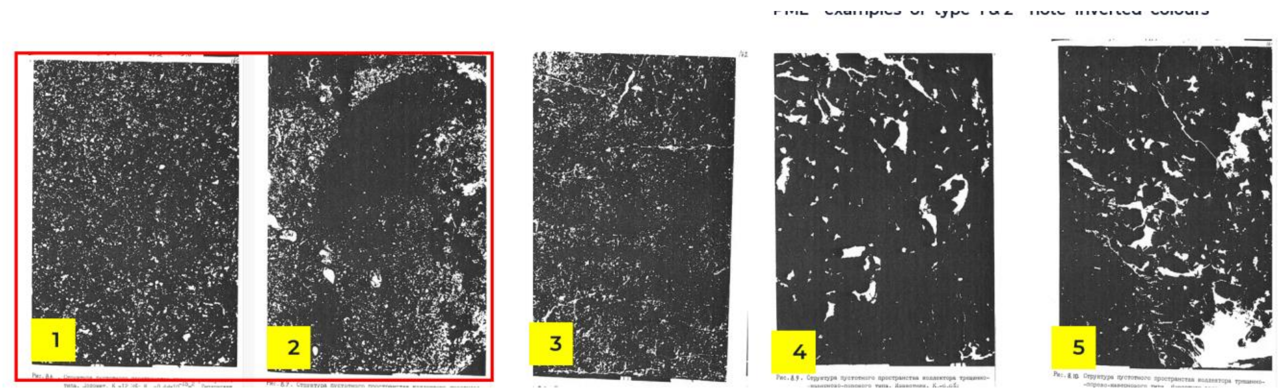


Figure 4-5 Five of the six main types of pore geometry as defined in core description

All existing studies result in the same general conclusion that reservoir properties of Artinskian reservoir rocks were greatly improved by leaching, which produced secondary vuggy porosity. The objects of leaching process were primary pores, bioclasts (selective leaching) and fractures. Reef carbonates were most prone to leaching due to highest primary porosity.

It is worth noting the fracture-related leaching porosity will have an effect on the general level of fracture porosity but the permeability of the fracture system would be still controlled by the average (or minimum) fracture aperture.

There is a lack of a reliable poro-perm trend observed in the Artinskian core data, as is typical for low porosity fractured carbonates in other fields around the world. In general, it can be assumed that the reservoir rocks in Teplovskoye–Tokarevskoye area are characterised by a continuum of rock types and porosity which are in line with a generic range of carbonate reservoir classification. There is no clear trend that would allow us to characterise a certain lithotype, field, well or area with the exception of fracture-dominated intervals, which are underrepresented but visible on porosity-permeability cross plots, as highlighted in Figure 4-6.

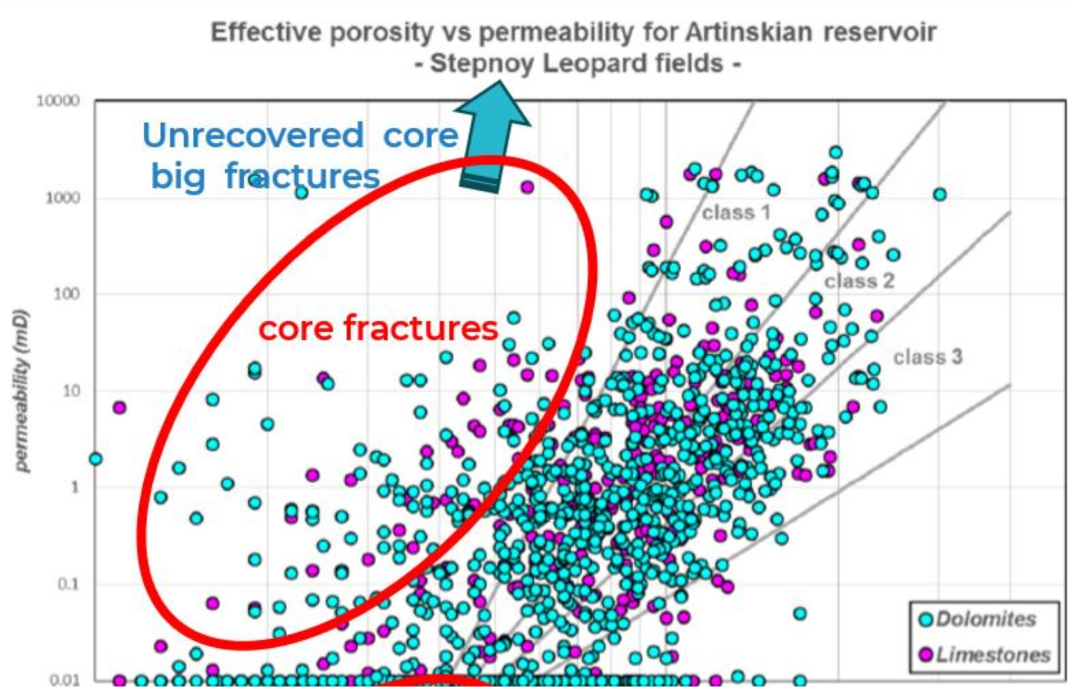


Figure 4-6 Porosity-Permeability Cross-plot for Artinskian Reservoir

The poro-perm analysis shows the continuous wide cloud of points with no clusters or distinct dependency on lithology, well or field.

The core points outside the generic "porous carbonates" poro-perm are obvious and are related to fracture presence and represent a continuum as well, with gradual departure from the porous reservoir behaviour to more fracture-dominated systems.

Bigger fractures (with possible fracture porosity enhancement by the leaching vugs) are not represented in core studies due to core acquisition limitation in those intervals, but will have a significant impact on the well productivity in those intervals.

4.2.2 Formation Evaluation

General Methodology description

The complex mineral composition encountered through the section, with a mix of carbonates, evaporites, and occasionally shales and marls, means that the standard clastic reservoir interpretation techniques have limited applicability, and will have increased uncertainty because of the varying matrix composition and complex porosity structure effect on different log measurements. It is common industry practice to employ the muti mineral solver-based techniques for complex composition carbonate/evaporitic formation to capture the matrix variability and porosity structure complexity.

Multiple implementations of multi-mineral solvers are commercially available in log interpretation software packages such as ELAN (Schlumberger) Multi-min (Geolog) and Multimineral Solver in Interactive Petrophysics (IP). The latter was used by Nostrum to create the interpretation model for the Stepnoy Leopard wells.

The basic principle of multi-mineral solver application is that if the interpretation model contains N formation components (minerals and fluids) then the model is determined and solvable if there are N-1 input logs (also called equations). The extra default equation is the Unity condition implying the sum of all the components has to be equal to 1. Nostrum's interpretation workflow and multi-mineral model was based on the previous work performed by NIPIneftegaz in 2020.

The model used for the quantitative formation evaluation included the following mineral components:

- Halite
- Anhydrite
- Clay minerals (with associated bound water)
- Limestone
- Dolomite

The fluid components were:

- Free Water
- Oil

Giving a Total of 7 model components to solve for.

The available log curves (equations) for use within the workflow vary from well to well, with the most complete dataset being:

- Gamma Ray
- Neutron (processed and calibrated)
- Sonic
- Density (in key wells only)
- Laterolog resistivity (assumed to be RT in high resistivity / Saline mud environment)

The number of available logs (equations) in the dataset adds up to 5.

Therefore, this is insufficient to solve the problem completely, as there are more components than logs (equations) +1. To overcome this limitation, a zonation based on regional knowledge and generic log response and character was implemented to reduce the number of formation components in the model for different intervals. For example, the core and drilling data suggests salt presence only in the upper section of the Artinskian reservoir interval and a lack of clay presence in the evaporitic section. The model used for the upper section did not include the clay component and therefore allows for a solution. The lower section in turn has no halite in the matrix component so the model did not include halite as a mineral component, thus enabling a solution.

An example of the multi-mineral interpretation results and input logs QC overlays by Nostrum is presented in Figure 4-7.

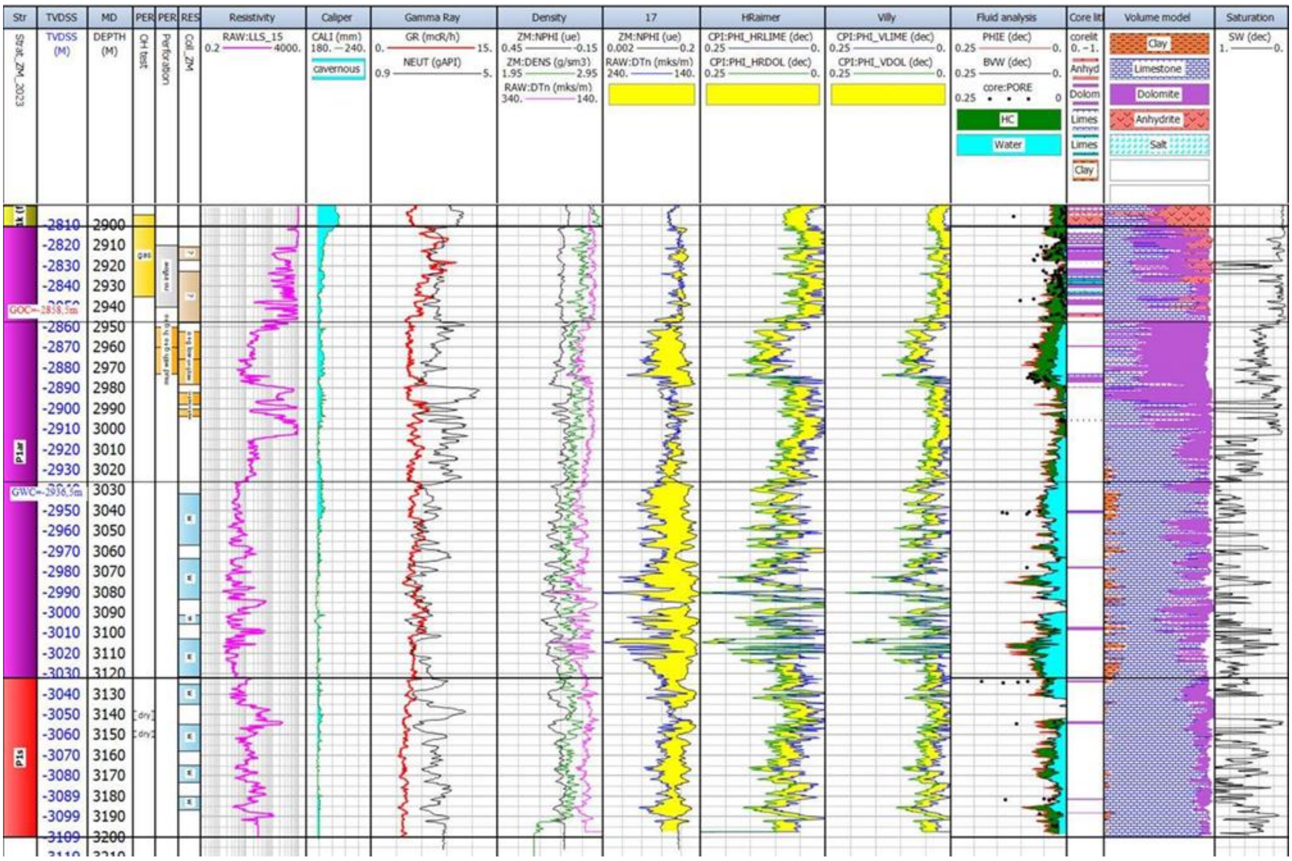


Figure 4-7 Nostrum Multimin interpretation Well EGR-22

The sonic response model in the workflow used by Nostrum is the non-linear Raymer Hunt equation, which is appropriate for low porosity, fast carbonate formations and is more applicable than the time-average Wyllie equation.

Water saturation was evaluated using the only available Laterolog data as the resistivity input and standard Archie equation with the following parameters:

- m = 2.2
- n = 1.94
- Rw: P1ar - 0.018 ohmm
- Rw: P1k – 0.03 ohmm

The Archie parameters are in agreement with the standard range for a fractured low porosity formation, but it is worth noting that complex fractured carbonates exhibit non-Archie behaviour and resistivity-based saturation evaluation has high uncertainty, and can be significantly affected by the presence of fractures, vugs and complex porosity structure. In the absence of any advanced logs and image data for lithotyping or reliable core measurements and capillary pressure data, the Archie based saturation can be used as a guide for hydrocarbon saturation estimate but should be used with caution.

Limited log dataset methodology

A typical Soviet log data set will include the density measurements only in the key wells and some old wells would have been drilled before density logs were commonly available. The majority of the Stepnoy Leopard wells will only have Sonic and Neutron as porosity logs available for the interpretation.

The lack of density log measurements means there are only four available inputs and introduces the issue of the number of equations to solve for being limited to five.

As an attempt to maximize the use of the data available, Nostrum had decided to use the synthetic density log in limited dataset cases and use the Gardner equation to derive a pseudo-density log for use within the interpretation multimin model.

Although it is not 100% technically correct to use the log data derived from other log measurement as the independent input to multimin models, there are techniques for introducing the relationship between volumes of components in the limited log data situation (the Constant Tool equation). As a uniform sonic to density transform was used in SL fields, and it has been calibrated to match the real density data in key wells with the best fit, the use of sonic-derived density in the interpretation model is analogous to introducing a constant tool equation into the model, which is the normal practice when there is a limited dataset.

There is a positive side effect of using Soviet Neutron-Gamma log rather than Thermal Neutron data on lithology evaluation in the multimin workflow because the Neutron-Gamma log is more sensitive to lithology and allows the system to pick lithology differences based on the Sonic, Neutron, and even Sonic-derived density as the input.

There is no doubt that the lack of the real acquired density data and using the synthetic log in Multimineral solver approach introduces additional bias and uncertainty to the interpretation results, but given the complexity and variability of the formation using the multimineral approach is still more reliable and provides better understanding of lithology, and as a result a better porosity evaluation, compared to the single curve fixed matrix approach. Nostrum has also performed model verification and fine tuning to the core data when available. Existing core comparisons show a reasonable agreement to the interpretation results using the IP multimineral solver.

4.2.3 Conclusions

The Stepnoy Leopard log data quality and availability is quite limited and typical for this vintage of Soviet datasets. This introduces additional challenges to log data interpretation.

The complex mineral composition and pore structure limits the use of standard simple techniques for formation evaluation.

The use of the Multimineral approach chosen by Nostrum as an interpretation methodology is justified and applicable to maximise the use of all available data.

The application of synthetic density log as multimin input is a fit for purpose solution and has been checked and verified using the core data where possible.

4.3 Field specific geology and Static Model

The Artinskian is part of a carbonate complex, which is the latest major subsalt cycle of carbonate deposition within the basin in the Moscovian-Artinskian shelf. It can reach 900 to 1,000m thick, and up to 1400m in the shelf rim. It is characterized by dolomites formed by both early and late diagenetic dolomitization and underwent later anhydritization. The Artinskian and Filippovski horizons were deposited in the post-rift phase of geodynamic evolution of the basin and did not undergo significant tectonic deformations. The Artinskian barrier reefs contain the largest hydrocarbon accumulation and are overlain by Kungurian anhydrite seals (Figure 3-2).

Nostrum built a suite of static models of the Artinskian reservoir for the four easternmost Stepnoy Leopard fields: Gremyachinskoye (Grm), East Gremyachinskoye (Egr), West Teplovskoye (Wtp) and Teplovskoye (Tpl), in late 2023-early 2024 (Figure 4-8).

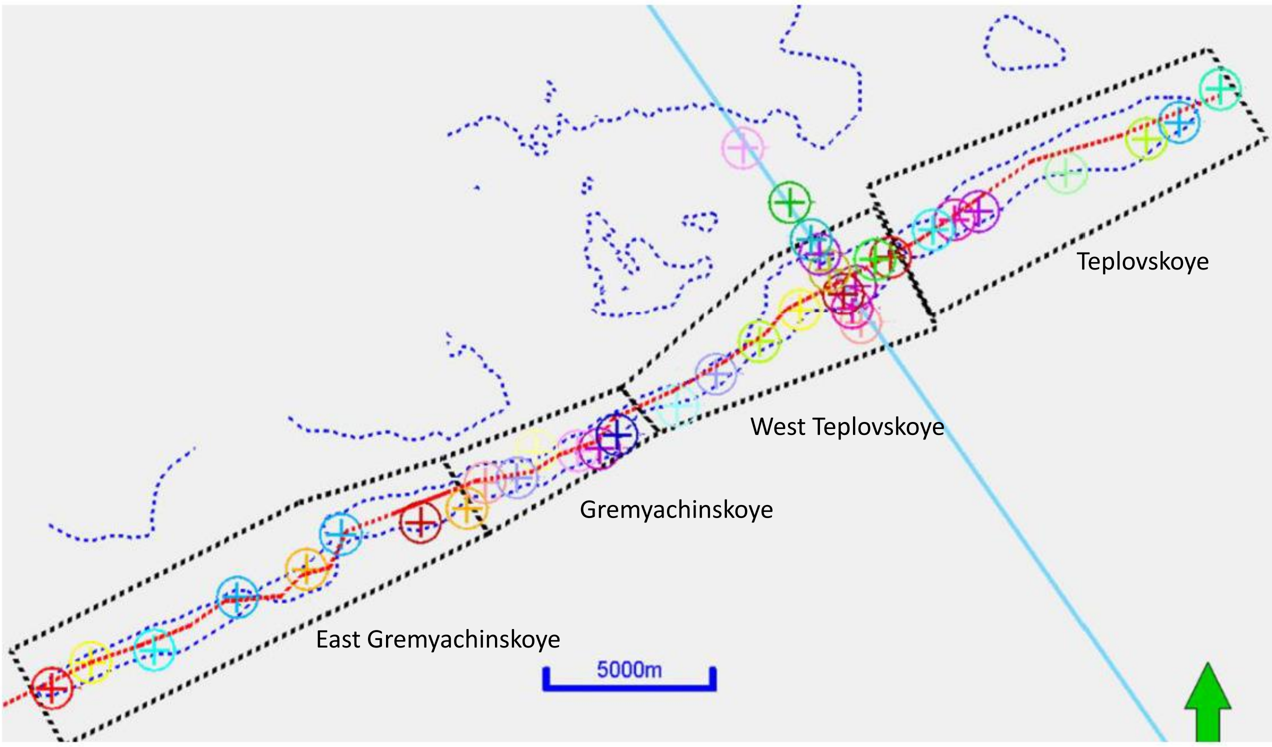


Figure 4-8 Extent of Static Model

From Report: 956-GG-REP-0001

Xodus has received copies of the models and documentation which have been reviewed as part of this CPR. Xodus is satisfied that the static models capture the range of geological uncertainty in the current understanding of the in-place volumes.

A single structural model was built covering all four fields, using the Artinskian and Sakmarian surfaces described in Section 4.1. Well logs and tops were used from the 76 wells provided, although the full log suite is not available in all wells and not all wells penetrate the full reservoir interval. Approximately half the wells lie outside of the hydrocarbon-bearing zones.

The Artinskian to Sakmarian interval was further subdivided into 8 zones, on the basis of GR and PHIE logs. The model grid is unfaulted, and the cells are 25m x 25m x 1.5m, oriented parallel to the reef trend. Cross-sections through the model are shown in Figure 4-9 and Figure 4-10.

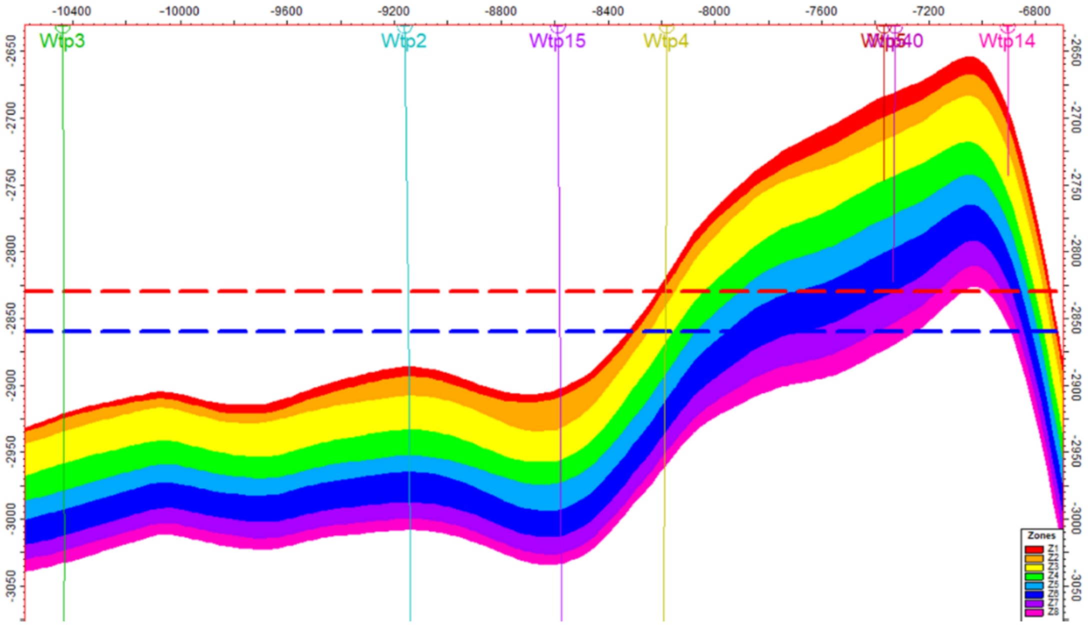


Figure 4-9 NW-SE Model Zonation Cross-Section through West Teplovskoye

From Report: 956-GG-REP-0001 (Blue line of section in Figure 4-8)

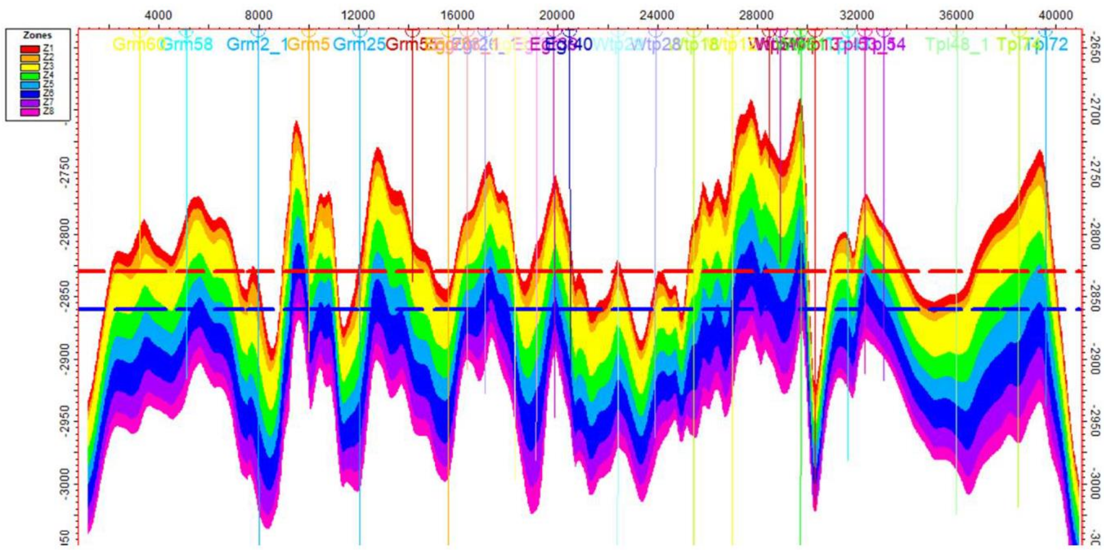


Figure 4-10 SW-NE Model Zonation Cross-Section along Reef Axis

From Report: 956-GG-REP-0001 (Red line of section in Figure 4-8)

PHIE was upscaled into the model grid and modelled in the inter-well volume using a reservoir thickness trend (a proxy for facies distribution in the absence of sufficient data to produce a reliable facies interpretation), combined with a stochastic algorithm to add a degree of "randomness" to the porosity distribution. This has the effect of forcing higher porosity into the thicker reefal areas, and lower porosity into the backreef areas, consistent with the geological conceptual model. By varying the degree of contribution of the thickness trend and the stochastic elements, a range of porosity realisations were generated.

For each porosity realisation, a NTG property was generated using a porosity cutoff of 0.04 in the gas leg, and 0.06 in the oil leg. Thus, NTG varies with changes to porosity and GOC.

Sw was determined using two heights above contact functions, one applied to cells where PHIE <0.054 and the other to cells where PHIE >0.054. Thus, Sw varies with changes to porosity and OWC.

Based on a thorough review of log and well test data including from the re-entry of wells Tpl-72 and -74 in 2023/24, corroborated by an analysis of the structural spill points, the approach to contact interpretation can be simplified from that used previously into single field-wide contacts for all four fields. The range of contacts interpreted were assigned such that oil volumes are minimised in the low case and maximised in the high case. The lack of pressure data, uncertainty in the structural spill points, as well as ambiguity in the log interpretation and well test data mean that a wide range of contact uncertainty is present. The contacts are summarised in Table 4-1.

	GOC /m TVDSS	OWC /m TVDSS
Low Case	-2835	-2855
Mid Case	-2830	-2860
High Case	-2825	-2870

Table 4-1 Range of Contacts for the Eastern Fields

An uncertainty workflow was set up to determine the P90, P50 and P10 volumetric cases, this incorporated porosity and contact variables (and therefore also resulted in a range of NTG and Sw properties) as well as a GRV multiplier, which was used to capture the structural uncertainty.

The workflow was run 100 times for each field to generate a range of volumetric outcomes. The cases were sorted by hydrocarbon pore volume (HCPV) and P10, P50 and P90 HCPV cases were selected for dynamic modelling. HCPV was chosen as the determining output since, due to the nature of the contact uncertainty, a high STOIIP case, tended to correspond to a low GIIP case and vice versa. Therefore, it was decided to handle the contact uncertainty in the simulation model phase and further explore sensitivity to fluid type in the dynamic model.

For the three selected cases, a permeability model was generated using permeability from the wells and co-kriged with each porosity model to achieve an appropriate level of heterogeneity.

Whilst Xodus agrees with the overall modelling approach and the resultant in-place volumes, the model for the four Eastern fields does not fully account for the presence of fractures and vugs, in relation to their enhancement of permeability. As discussed in Section 4.2.1, the dataset under-samples open fractures due to the inherent difficulties in recovering core over fractured intervals. Consequently, it is likely that the static model is pessimistic with respect to permeability. However, without a reliable core or image log database it is impossible to predict the frequency, length and aperture of these fractures and thus determine exactly how and where they will impact on permeability. The nature of these open fractures is explored further in the dynamic model and is discussed in Section 4.5.

4.4 In place Volumes and Uncertainty

The final volumes for each field are shown in Table 4-2.

Volumes in Metric/Oilfield Units	Volume Run	Case Equivalent	GRV	Net Volume	Pore Volume	HCPV in oil	HCPV in gas	Summed HCPV	STOIIP in oil	STOIIP in gas	STOIIP	GIIP in gas	GIIP in oil	GIIP
			Mm³						*MMbbl*			*Bcf*		
Teplovskoye	Tpl_LOWCASENEW1_2830-2855	P90	393,447	290,258	23,130	4,516	12,151	**16,667**	18.9	3.5	**22.4**	111.8	21.0	**132.8**
	Tpl_BASECASENEW1_2830-2860	P50	435,867	346,291	32,427	8,133	15,470	**23,603**	34.0	4.5	**38.4**	142.3	37.9	**180.2**
	Tpl_HIGHCASENEW1pvm_2830-2870	P10	528,342	465,964	45,447	15,156	18,720	**33,876**	63.3	5.4	**68.7**	172.2	70.5	**242.7**
West Teplovskoye	Wtp_LOWCASENEW1_2830-2855	P90	596,211	501,744	41,695	5,069	28,143	**33,212**	21.2	8.1	**29.3**	258.9	23.6	**282.5**
	Wtp_BASECASENEW1_2830-2860	P50	630,546	562,280	54,194	8,759	34,757	**43,516**	36.6	10.1	**46.6**	319.7	40.8	**360.5**
	Wtp_HIGHCASENEW1pvm_2830-2870	P10	703,174	664,938	70,765	15,980	41,445	**57,425**	66.7	12.0	**78.7**	381.2	74.4	**455.6**
East Gremyachinskoye	Egr_LOWCASENEW1_2830-2855	P90	200,920	152,949	12,443	2,310	6,756	**9,066**	9.6	2.0	**11.6**	62.1	10.8	**72.9**
	Egr_BASECASENEW1_2830-2860	P50	219,953	175,187	16,554	3,921	8,302	**12,223**	16.4	2.4	**18.8**	76.4	18.3	**94.6**
	Egr_HIGHCASENEW1pvm_2830-2870	P10	260,727	211,814	19,077	6,053	8,300	**14,353**	25.3	2.4	**27.7**	76.3	28.2	**104.5**
Gremyachinskoye	Grm_LOWCASENEW1_2830-2855	P90	512,700	408,815	34,039	5,985	19,343	**25,328**	25.0	5.6	**30.6**	177.9	27.9	**205.8**
	Grm_BASECASENEW1_2830-2860	P50	555,660	451,279	41,788	9,279	22,198	**31,477**	38.8	6.4	**45.2**	204.2	43.2	**247.4**
	Grm_HIGHCASENEW1pvm_2830-2870	P10	646,279	551,780	50,749	15,201	23,569	**38,770**	63.5	6.8	**70.3**	216.8	70.8	**287.6**

Table 4-2 Eastern Fields Static Model Volumes by Field

From Report: 956-GG-REP-0001

The oil volumes calculated in Teplovskoye, West Teplovskoye and Gremyachinskoye are similar (approx. range of 20-35-65mmbbls), whereas those in East Gremyachinskoye are slightly smaller (10-16-25mmbbls). There is more variability in the gas volumes, with West Teplovskoye having the largest, followed by Gremyachinskoye and Teplovskoye, with East Gremyachinskoye having the smallest gas volume.

The static model was upscaled into the dynamic model, resulting in less than a 2% difference for the in-place volumes between the fine-scale and coarse-scale models. The P10, P50 and P90 models were then initialised with updates to Sw, Sor, Sgr and the fluid PVT, and a range of dynamic sensitivities were analysed. This resulted in dynamic model in-place volumes referred to as the Final Development Dynamic Model. These are summarised in Table 4-3 and the modifications to the dynamic model are discussed further in Section 4.5. The GIIP includes both free gas in the gas cap and associated gas from the oil leg.

GIIP /BCF STOIIP /MMBBLS	P90		P50		P10	
	GIIP	STOIIP	GIIP	STOIIP	GIIP	STOIIP
Final Development Dynamic Model	531	122	784	174	1134	231

Table 4-3 Dynamic Model In-place volumes

4.5 Dynamic Model Build and History Matching

The key uncertainties for input into the dynamic models, prior to History Matching were:

- Condensate Gas Ratio (CGR)
- Oil and Gas Relative Permeability curves
- Size (and Strength) of Aquifer
- Influence of Fracture parameters on Water breakthrough times

Reservoir Net-to-Gross (NtG), porosity and permeability properties were generated as a part of the static modelling and were directly adopted in dynamic models after upscaling

For the Condensate Gas Ratio (CGR) the data acquisition in 2023/24 on Tepl 72 and 74 indicated a P50 base estimate of 50 bbl per mmscf. A sensitivity range for the P90 / P10 cases of +/-10% was assumed.

For the relative permeability, end-point scaling was used. Particular focus was paid to the Residual Oil saturation (Sor), the trapped gas saturation (Sgt) and the Critical / Irreducible Water saturation (Swir). Due to the lack of a reliable set of relative permeability data being available, a set of estimated Corey water-wet curves, allowing for a wide range of outcomes, were derived. The details of the approach to the relative permeability modelling are given in the Eastern Fields Dynamic Modelling Filenote[1].

This approach was reviewed by Xodus, and deemed reasonable given the natural uncertainty range of any subsurface data set.

The History Matching process followed by Nostrum for the P90, P50 and P10 dynamic models considered which datasets were more complete and potentially reliable. Production and test data is available for all of the eastern fields and varies significantly from a single 2-day flow-period to extended test periods over a month. All available test and production data for Gremyachinskoye, East Gremyachinskoye, and West Teplovskoye accumulations was collected in the 1970s and 1980s and have limited duration (max 6 days per test). Limited records exist regarding the tested intervals, gauge depths and accuracy of recorded data for these tests.

In contrast to other fields, the Teplovskoye field has significant test and production from the past, and the Tpl-74 well was also tested in the 2023-2024 appraisal campaign. The recent Tpl-72 and Tpl-74 appraisal program included acquisition of cased-hole logs and transient pressure data, together with testing of gas cap and oil-rim intervals. Therefore this is a good data set to estimate well productivity and likely longer term production forecast characteristics. As a result the Teplovskoye data-set and field was selected for the history matching exercise.

The average permeability in the model is seven times lower than permeability obtained from the test interpretation It was for Tpl-74. Pressure data collected during the recent campaign shows pressure communication between wells Tpl-74 and Tpl-72 and circa 5-6 bar pressure depletion due to the limited production since 1990. Newly collected cased-hole log data shows changes in the fluid saturation along the wellbore associated with production. These observations along with historically recorded rate and pressure data were used in calibrating the P50 model as described below.

[1] *Filenote: Stepnoy Leopard Eastern Fields Dynamic Modelling – Denis Zubarev*

A high permeability multiplier is required for history matching and is supported by the difference in base model average permeability and PTA derived permeability discussed above. The base model permeability being materially lower than the actual PTA estimate.

Large skin factors (20-30) are required to match earlier (pre 2023 / 2024) production due to suboptimal well stimulation. Significantly lower skin factor was obtained in the recent well re-entry campaign due to the additional perforations and significantly larger acid volumes used in the 2023 / 2024 stimulations.

The initial well testing done in 1990 gives a poor match for bottom-hole pressure and rates with the P50 model because of low well and model deliverability. Modification of the model permeability and completion skin factors addresses this problem. However, the tests show that the gas to oil ratio (GOR) of the P50 model is significantly lower than the observed data. This indicates that during the test larger amounts of free gas were produced, which requires the gas-oil contact (GOC) to be deeper and closer to the perforations Adjustment of the GOC from 2825m to 2830m has addressed the issue and enabled a match of the GOR. Larger skin factors (up to 20) were used for tested zones in the final calibrated model.

The increased permeability and well skin factor corrections deliver good matches for gas rate, oil rate and bottom-hole pressure for the first two tests performed in 2024 in the gas cap. For test #3, conducted in the oil zone, a good match of rates and pressure was also achieved. A negative skin factor was used in order to match well productivity for both gas and oil tests, which is in line with additional perforations and significantly larger acid volumes used in the well stimulation in 2023 / 2024.

The observed pressure depletion in the Teplovskoye field was matched by the P50 model. The pressure reported at the reference depths during tests in 1990 and 2024 supports 5-6 bara depletion, which is similar to the pressure observations made during the recent appraisal campaign. This confirms that the modelled aquifer size is reasonable and does not require major adjustment.

Finally, given the depositional environment (carbonates) and regional analogues, it is quite likely that the improved reservoir permeability and connectivity, necessary to achieve a history match for Tpl-74 is due small scale natural fracturing. However the current data set does not allow explicit modelling of the fractures. Natural fractures, as well as boosting productivity, also has the potential to lead to premature water breakthrough. Hence it was necessary to assess this risk, and how to manage the uncertainty associated with it. Xodus has reviewed the original geological work from the 1991 and 1996 PML reports and based on these, Xodus considers that premature water breakthrough as a result of natural fractures and vugs (secondary porosity) in the reservoir is unlikely. Fractures are small and localised, rather than being the long, extensive fracture corridors that allow rapid water breakthrough seen in other fractured carbonate fields around the world. Nostrum has undertaken sensitivity analysis to consider the detrimental effect of water, as a function of fracture length, on the cumulative oil and gas recovered with time. This analysis predicts that fracture lengths greater than 50m are required for a material detrimental effect. The expected fracture lengths in the Stepnoy Leopard fields are less than 10m. However to allow for the possibility of premature water-breakthrough in a P90 scenario incremental well capex will be assumed (see next section).

To summarize, Teplovskoye field history matching leads us to the following conclusions:

- The size of the aquifer introduced into the model is reasonable and agrees well with the observed pressure depletion.

- The absolute permeability of the P50 model is significantly lower than required to match well productivity and should be increased.
- The modelled reservoir connectivity seems to be conservative.
- The well stimulation performed by Nostrum in 2023 / 2024 provides significant well productivity improvement.

Despite multiple factors suggesting that the flow characteristics in the model could be improved, the decision was made to proceed with a more conservative approach until findings are confirmed through early production data in the development phase.

4.6 Field Development Plan and Production Forecast

Nostrum's development plan demonstrates a desire to produce the oil rim, but that the ultimate prize is the gas cap with associated condensate liquids. The Eastern Stepnoy Leopard fields will be developed with a two-step process for each production well.

1) Initial hydrocarbon production from a horizontal lateral placed at the gas-oil contact (GOC) to avoid early water-breakthrough from the aquifer.
2) Abandonment of the horizontal section once it waters out and recompletion of the well in the gas cap, where this section of the well will be closer to vertical.

This strategy is based on sensitivity runs carried out by Nostrum. It allows early gas production while slowing down invasion of liquids into the gas cap, and provides additional recovery of liquid hydrocarbons.

Nostrum's sensitivities show that the optimum water-cut at which to abandon the horizontal part of the wells is approximately 75%. The location of wells is the same for the P90, P50 and P10 cases. However, the depth of the horizontal completions will vary based on the GOC for the P90, P50, P10 case models.

The volumes oil and gas recovered are summarised in Table 4-4.

RESERVES (TO 01/01/2045)	GAS /BCF			OIL & CONDENSATE /MMBBL			LPG /KTONNES		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Eastern Fields	268.75	402.29	532.88	16.63	24.66	32.03	272.65	408.12	540.61

Table 4-4 Eastern Fields Reserves (To 01/01/2045)

The licence expires on January 1st 2045, but volumes are technically recoverable beyond this date in all cases. These volumes have been included as Contingent Resources in the CPR reporting and summary tables (Table 4-5).

CONTINGENT RESOURCES (TO 01/01/2090)	GAS /BCF			OIL & CONDENSATE /MMBBL			LPG /KTONNES		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Eastern Fields	57.10	130.40	302.90	0.54	1.72	6.70	55.00	125.60	291.75

Table 4-5 Eastern Fields Contingent Resources (To 01/01/2090)

The Technical recovery factors are summarised in Table 4-6. These technical recovery factors (not allowing for licence expiry or economic thresholds) are reasonable for this type of reservoir system where there is a laterally extensive oil rim overlain by a large gas cap. These recovery factors are based on a field gas production time cut-off of 1st January 2090, by which time the field gas rate is <3mmscf/d, even for the P10 case.

TECHNICAL RECOVERY FACTOR	P90	P50	P10
Gas	65.0	72.1	77.2
Oil	13.8	15.8	16.9

Table 4-6 Eastern Fields Technical Recovery Factors

Several factors impact recovery of gas and liquids such as lower permeability and low reservoir connectivity. These factors promote oil-rim smear over the gas cap, which reduces liquids recovery and at the same time reduces gas recovery due to high trapped gas saturation. Over time, water pushes oil into the gas cap past the horizontal sections, leaving stranded volumes in the form of residual oil saturation. Both oil and water also further invade the gas cap, leaving gas trapped. This mechanism is also responsible for the variation in recovery factors between the P90 and P10 cases.

In the P90 case the oil-rim and gas gap are thinner while water mobility is higher. This results in faster movement of water towards the wells and higher trapped saturation for oil and gas. The faster water breakthrough means more severe production decline and results in a lower recovery efficiency.

In the P10 case well productivity is less affected, and wells can sustain higher production rates. The thicker oil-rim and gas cap, combined with less favourable relative permeability for water results in lower trapped hydrocarbon saturations and thus overall better recovery.

Wells with more wellbore-to-reservoir contact and inflow control devices will also improve recovery of liquid hydrocarbons. In the dynamic modelling Nostrum has assumed a horizontal completion of 1,000m. It should be operationally possible to drill longer horizontal sections up to 1,500m. However, at this stage Nostrum has assumed a more conservative well and completion design. It will consider lateral and completion optimization for the later stages of development planning.

The length of vertical completion in the gas cap will be field dependent and is planned to vary from approximately 20m to 118m based on current planned well locations and the top structure of each field.

As a result of the analysis of the sensitivity of early water breakthrough to fracture length, Xodus has assumed that water starts to have an impact twelve months after a well is brought on production for the P90 case, and that $0.5 mm is spent on mitigation for each and every producing well. The typical mitigation is to isolate fractures from the wellbore. This can be achieved through installation of the blank pipe with swell packers across the fractures zone of the wellbore in the case of horizontal wells, or by a cement squeeze in a vertical well.

Assuming one well every three months for nine wells back to back means a total of $4.5mm is spent over 27 months. Additionally, we assume there is no ability for water export and so Nostrum will spend a further $4.5mm on a water disposal well. The total incremental capital expenditure on wells in the P90 case is therefore $9mm. In Xodus' opinion this is a conservative assumption to manage and mitigate a water risk that Xodus considers unlikely. No incremental expenditure is assumed for the P50 and P10 cases.

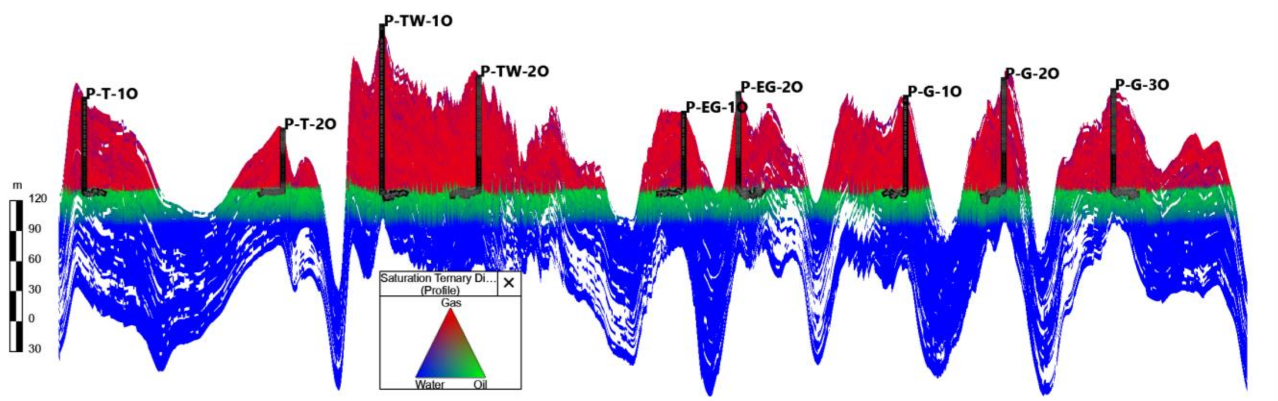
The Eastern field profiles were adjusted for system uptime as follows:

P90 / P50= 95%

P10 = 98%

This is based off the operating statistics achieved at Nostrum's Chinarevskoye Operations.

Overall, the proposed development plan, and the static and dynamic models that underpin it, incorporate a certain degree of conservatism. Nostrum has taken a conservative approach to initial water saturation and water relative permeability. Nostrum have also kept the dynamic model unchanged with a lower absolute permeability and lower levels of connectivity than those implied by the well test and history matching exercise, calibrated to the recent Tpl-72 and Tpl-74 well data gathering exercise. On the well performance side, Nostrum does not assume production benefits from inflow control devices and stimulation of the wells with acid.



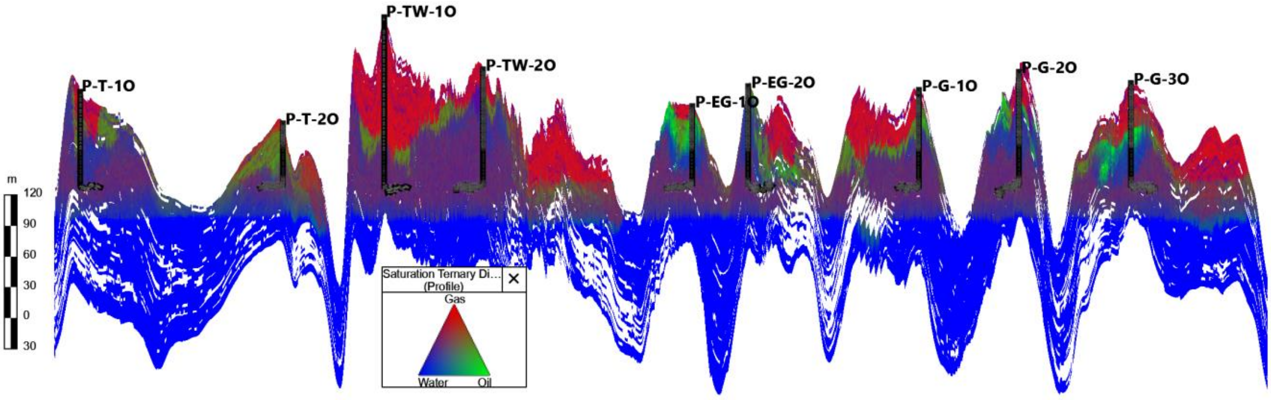


Figure 4-11 P50 Model Fluids Saturations: Initial (top) and Final (Bottom)

4.6.1 Facilities and Infrastructure Overview

The Eastern fields are planned to be developed on a Full Gas Blowdown basis, consisting of raw gas-condensate production from 9 wells located in 4 eastern segments being sent via an intra-field gathering system / trunkline, and an inter-field pipeline, supported by pressure booster compression at the pipeline inlet, to the existing processing facilities at the Chinarevskoe field. At the processing facilities the produced fluids will be de-sulphurised and the products (condensate, LPG and sales gas) will be produced. The new surface facilities are designed for up to 3.6MMSm³/d of raw gas-condensate production containing up to approximately 1% mol H_2S and 125 ppm mol total RSH (mercaptans).

A development concept schematic is shown in Figure 4-12 below:

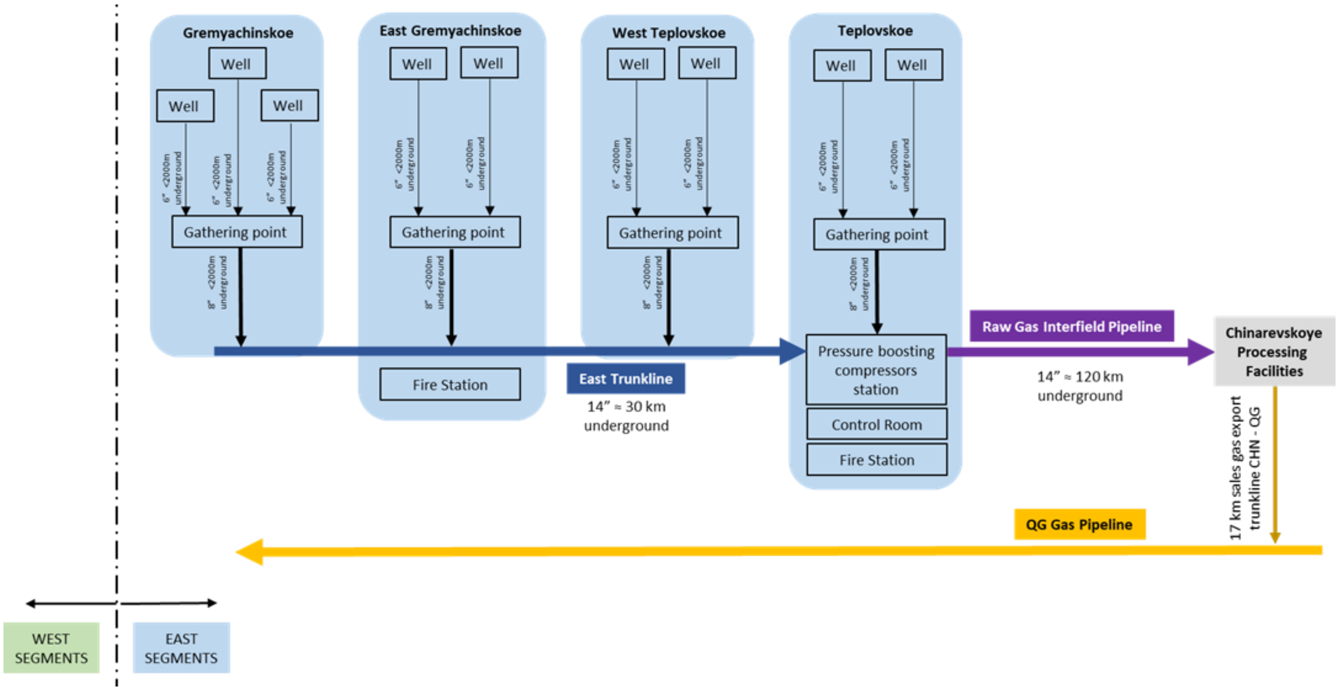


Figure 4-12 Eastern Fields Development Schematic

A map showing the proposed location of the key development elements is shown in Figure 4-13 below.

STEPNOYE LEOPARD FIELDS GATHERING SYSTEM PRELIMINARY CONCEPTUAL MAP

EAST SEGMENTS 1 - Teplovskoe Segment 2 – West Teplovskoe Segment 3 – East Gremyachinskoe Segment 4 – Gremyachinskoe Segment

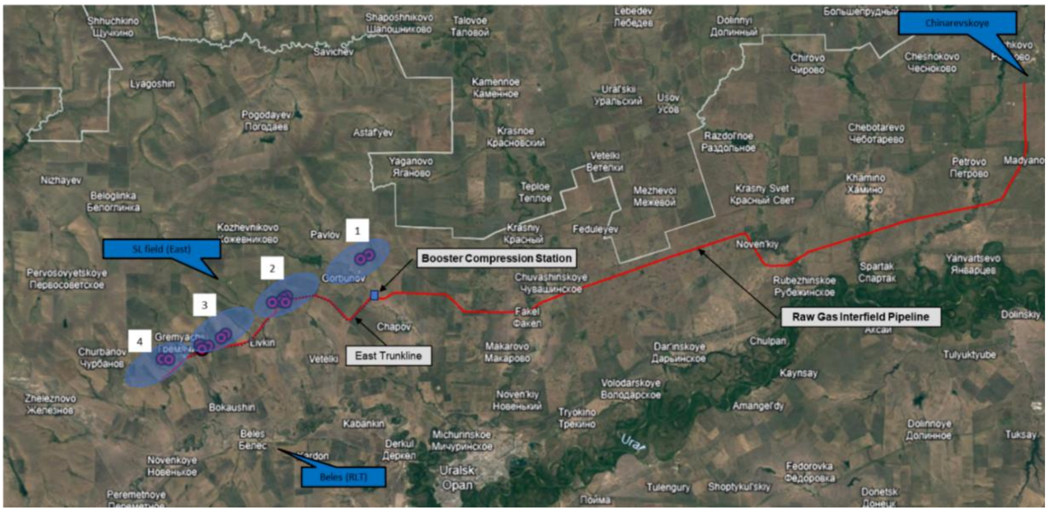


Figure 4-13 Eastern Field Gathering System Conceptual Map

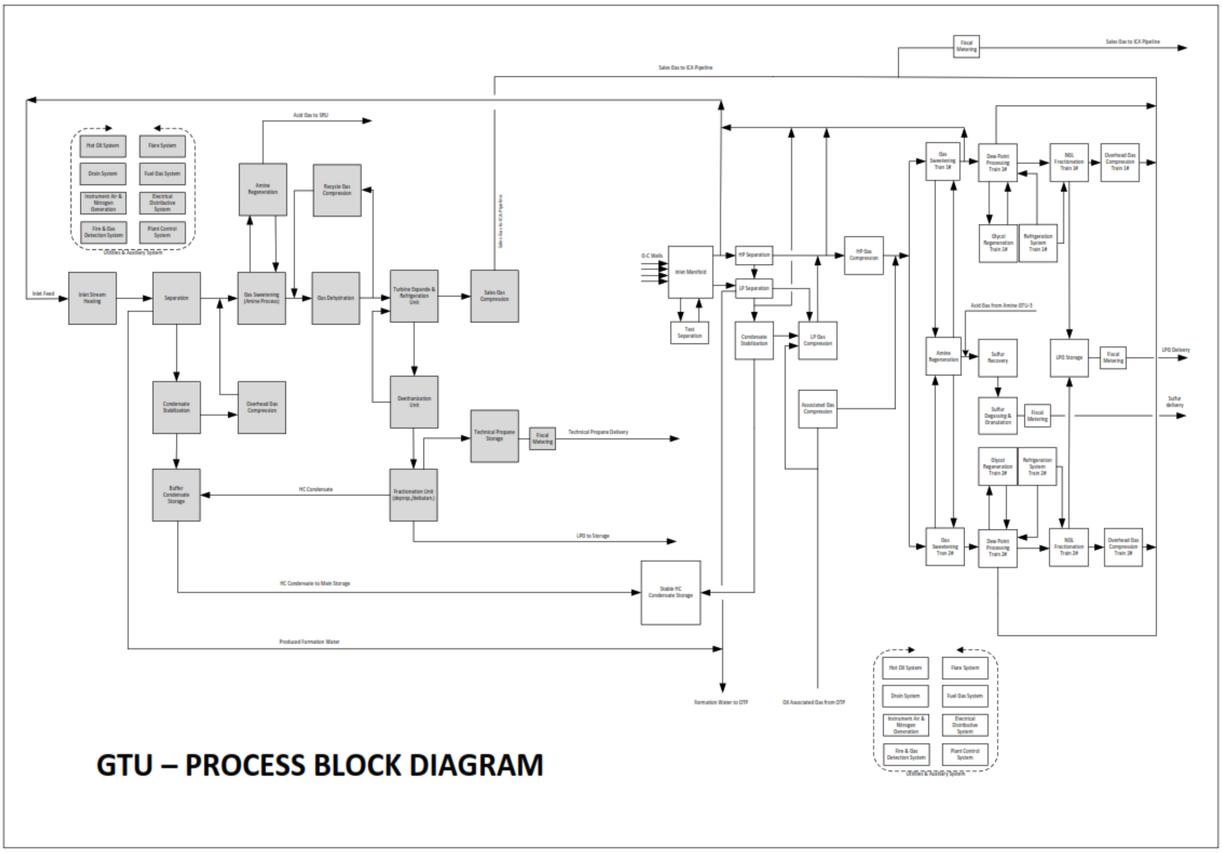


Figure 4-14 Existing Gas-Condensate processing Facilities at Chinarevskoye

4.6.2 Product Yields

In order to determine the product yield rate for the Eastern fields, Nostrum performed HYSYS process simulation modelling of the surface facilities using the estimated composition of the produced Eastern fluids to determine the product rates. Subsequently, Nostrum revised their composition estimate for the produced fluids and recalculated the likely impact on the product rates (and hence yield rates) based on the change in component mass flows of the produced fluids. Xodus has not checked the original simulations or the subsequent calculations, but the methods used to determine the yield factors appears reasonable. The yield factors provided by Nostrum for each product stream are shown in Table 4-7 below:

PRODUCT	YIELD FACTOR (%)
Condensate (factor to oil production)	80
LPG (factor to gas production)	0.0034
Sales Gas (factor to gas production)	94.9

Table 4-7 Eastern Segments Yield Factors

4.7 Costs

Xodus has reviewed the latest Nostrum Capital Expenditure (CAPEX), Operating Expenditure (OPEX) and Abandonment Expenditure (ABEX) assumptions and plans for the 9 well development programme for the Eastern fields. These are discussed separately below.

4.7.1 CAPEX

Nostrum has developed their Class III cost estimate using a combination of early phase engineering (i.e. preliminary route selection for the gathering systems and inter-field pipeline and flow assurance analysis), budgetary quotations from vendors and use of historical norms e.g. standard well-site configurations at the Chinarevskoye (CHN) field and similar booster compression facilities installed in another field in 2023.

Drilling and Wells

Nostrum is planning a 9 well development with drilling due to take place across 2026 (4 wells) and 2027 (5 wells) with first gas targeted for December 2026.

Xodus reviewed the CAPEX estimate for the drilling programme and considers the majority of the costs to be reasonable. The well costs are based on current rig market rates and historical Chinarevskoye drilling and completion durations. The total drilling cost estimate provided by the Nostrum was $62.78 million. Xodus has included an incremental $128k contingency for rig mobilisation and supporting costs to align with the 10% contingency included for each well in the drilling costs provided by Nostrum, taking the total drilling cost to $62.91 million. For the P90 case, the drilling CAPEX estimate was increased by $9 million (to a total of $71.91 million) to account for the following:

- Xodus has assumed that Produced Water (PW) arrives after 12 months and to manage and mitigate it a spend of $0.5 million per production well is required. The typical mitigation is by isolating fracture from the wellbore. This can be achieved through well workover for installation of the blank pipe with swell packers across the fractures zone of the wellbore in case of horizontal well; and by a cement squeeze in vertical well. We assume this mitigation is required on 1 well every 3 months back to back, so the total cost of mitigation measures will be an incremental $4.5 million over 27 months (=3x9 wells).
- Additionally, for the P90 case, Xodus has assumed that Nostrum do not receive dispensation for water to be sent to the CHN processing facility via the gas pipeline and instead requires to be disposed of locally via a single PW disposal well at an incremental cost of $4.5 million.

Pipeline & Surface facilities

Nostrum provided details of their CAPEX estimates for the gathering system, booster compression facilities and the inter-field pipeline.

Based on interviews with Nostrum personnel, Xodus were advised that the CAPEX estimate already included 10% contingency for delivery and construction activities associated with the gathering system, booster compression facilities and the inter-field pipeline. Xodus has also included for an incremental 10% contingency on the support facilities and engineering design.

It is noted that in the P90 case, the surface CAPEX estimate is decreased by $5.5 million to account for the one less booster compressor package being required due to the lower gas flow rates ($5 million each + 10% contingency). The impact on the overall pipeline and surface facilities estimate is shown in the table below.

CASE	NOSTRUM COSTS	CONTINGENCY ADDED	TOTAL
P90	$168.75 million	$1.69 million	$170.44 million
P50 & P10	$174.25 million	$1.69 million	$175.94 million

Table 4-8 Eastern Segments Pipeline & Surface facilities CAPEX

Total CAPEX

The overall impact of the contingencies and additional facilities described in the drilling and pipeline & surface facilities above are summarised in Table 4-9. These figures also include Project Management (to which Xodus has also added 10% contingency) and other costs.

CASE	NOSTRUM COSTS	CONTINGENCY ADDED	TOTAL
P90	$253.27 million	$2.97 million (contingency) +$3.5 million (additional facilities)	$259.75 million
P50 & P10	$253.27 million	$2.97 million	$256.25 million

Table 4-9 Eastern Segments Total CAPEX

Host Facilities

It is intended that the modifications required at the Chinarevskoye processing facility - an additional amine solvent sweetening unit to reduce H_2S levels, a new de-mercaptanisation unit to reduce RSH levels and a new incinerator for waste acid tail gas disposal – will be financed by its operator, Zhaikmunai LLP, who will be compensated through a processing fee.

4.7.2 OPEX

Xodus has used the latest Nostrum OPEX estimate as the basis for future field OPEX. The OPEX includes intervention costs, chemicals, maintenance, employee costs, firefighting service costs, well service engineer costs, personnel camp costs and the processing fee and the total amounts to $197.14 million over the lifetime of the licence as shown in Table 4-10 and Table 4-11.

Transport

For hydrocarbon volumes sold domestically no transport cost has been assumed. In each case the volumes are transported via Qazaqgas infrastructure and so any transport beyond Nostrum facilities is included in the sale price. For exported volumes Xodus has used Nostrum estimates that condensate is currently planned to be exported via rail at a cost of $10.5/bbl and LPG via truck at a cost of $20/tonne. Xodus considers these costs to be reasonable on the basis of Nostrum's prior experience of operating similar assets in the region.

4.7.3 ABEX

At the end of the licence period, an allowance has been made for abandoning all wells and surface facilities. Nostrum provided Xodus with detail of the estimated Abandonment Expenditure (ABEX) for the wells, well sites, flowlines/trunklines and gathering station facilities, assuming surface facilities are decommissioned and removed, with subsequent land recultivation and soil reinstatement. Xodus considers the base ABEX estimate of $6.95 million, developed by Nostrum, to be reasonable, however, we have included an incremental 10% contingency in the total ABEX, taking the total to $7.65 million. No allowance has been made for plugging and abandoning the Produced Water disposal well in the P90 case. It is assumed the cost for doing so will be less than the equivalent cost for the producing wells.

4.7.4 Forecast of Costs

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2024	0	1,210	7,406	8,616	0
2025	0	42,943	3,162	46,105	0
2026	31,648	124,283	1,072	157,003	1,015
2027	31,261	7,500	1,072	39,833	12,184
2028	0	0	1,072	1,072	12,184
2029	0	0	997	997	12,184
2030	0	0	175	175	12,184
2031	0	0	175	175	12,184

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2032	0	0	175	175	12,184
2033	0	0	175	175	12,184
2034	0	0	175	175	12,184
2035	0	0	175	175	12,184
2036	0	0	175	175	11,953
2037+	0	0	175	175	9,412
Total	62,910	175,936	17,400	256,246	197,136

Table 4-10 Eastern Field Forecast of Costs P50 and P10

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2024	0	1,210	7,406	8,616	0
2025	0	42,943	3,162	46,105	0
2026	31,648	118,783	1,072	151,503	1,015
2027	36,261	7,500	1,072	44,833	12,184
2028	2,000	0	1,072	3,072	12,184
2029	2,000	0	997	2,997	12,184
2030	0	0	175	175	12,184
2031	0	0	175	175	12,184
2032	0	0	175	175	12,184
2033	0	0	175	175	12,184
2034	0	0	175	175	12,184
2035	0	0	175	175	12,184
2036	0	0	175	175	11,953
2037+	0	0	175	175	9,412
Total	71,910	170,436	17,400	259,746	197,136

Table 4-11 Eastern Field Forecast of Costs P90

4.8 Economics

4.8.1 Methodology

Reserves and Net Present Values (NPVs) have been calculated using an Excel™ economic model prepared by Nostrum of Nostrum's interest (80%) in the four eastern Artinskian fields.

4.8.2 General Assumptions

General assumptions used by Xodus in the economic evaluation are tabulated in Table 4-12.

PARAMETER	VALUE
Discount Rate (Annual)	10%
Discount Methodology	Monthly
Cost Inflation	2% per annum
Evaluation Date	1st January 2024

Table 4-12 General Economic Assumptions

Xodus notes that the liquids produced in the four eastern fields consisting of oil and gas condensate are sold under a gas condensate agreement. Therefore, for the purposes of the CPR these are referred to together as condensate.

4.8.3 Fiscal Assumptions

A summary of the key fiscal terms that apply to the four eastern Artinskian fields are presented in Table 4-13.

ELEMENT	RATE
Corporate Income Tax	20%
Mineral Extraction Tax	Depends on volumes, for this development: Liquids Export – 5% Liquids Domestic – 2.5% Gas Domestic – 0.5%
Export Rent Tax	Dependent on oil price – varies between 14% and 19% using Xodus price assumptions
Property Tax	30% of assets subject to 1.5% tax
Excess Profit Tax	Ranges from 0-60%

Table 4-13 Key Fiscal Terms

Mineral Extraction Tax

Mineral Extract Tax (MET) is a tax on revenue, the rate of this tax depends on whether the hydrocarbon is for domestic use or export, and on the volume extracted in each year. The rate can be as high as 18% for export volumes, which exceed 120mm tonnes per year of exported oil. However, the production forecasts for the four eastern fields are low enough that in all scenarios the lowest tax rate is applicable.

Excess Profit Tax

Excess profits tax ranges from zero to 60% on the net profits earned. If in any year the ratio of net profit to tax deductions is more than 0.25. For increments above a ratio of 0.25 the taxable profit in that increment is subject to a higher rate of tax. The rate increases up to 60% for those profits where the ratio of net profits to tax deductions is more than 0.7.

Hydrocarbon Sales Destination

Based on information provided by Nostrum we understand that 100% of dry gas will be sold domestically, LPG sales will be split equally between domestic and export, and 20% of condensate sales will be domestic with the remaining 80% exported.

4.8.4 Commodity Prices

A summary of the commodity prices used in the model including any marketing discounts and the assumption behind them is included in Table 4-14. Xodus understands that the domestic prices for condensate and LPG are set by the Kazakhstan Ministry of Energy (MoE). As these numbers are fixed, we have not applied inflation to these prices in the same way that we have for export prices. However, in the past the MoE has increased the prices and it is possible they will do so again before or during production from the four eastern fields.

DESTINATION	COMMODITY & UNIT	JAN 27 PRICE	INFLATION	SOURCE/BASIS
Export	Condensate $/bbl	70.6 (63.6 in P90)	2% p.a. after Mar-31	Brent forward curve*, inflated at 2% thereafter minus an adjustment for market based discounts
	LPG $/tonne	333	2% p.a.	2017-2021 average Sonatrach LPG price minus an adjustment for market based discounts
	Dry Gas $/'000m^3	N/A	-	-
Domestic	Condensate $/bbl	37.7	None	120% of domestic crude oil price set by Kazakhstan Ministry of Energy (MoE) at $240/tonne
	LPG $/tonne	100	None	Set by Kazakhstan Ministry of Energy (MoE)
	Dry Gas $/'000m^3	44.13	In line with export condensate	As per Qazaqgas contract

Table 4-14 Hydrocarbon Sales Prices (Brent forward curve from Intercontinental Exchange Futures EU May 2024)*

4.8.5 Reserves Evaluation

Reserves	Gross in the four Eastern Artinskian Fields			Working Interest (80%)		
	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE
Sales Gas (BCF)	292.63	453.57	572.88	234.1	362.9	458.3
Condensate and Oil (MMSTB)	16.60	25.52	32.03	13.3	20.4	25.6
LPG (ktonnes)	296.88	460.15	581.19	237.5	368.1	464.9

Table 4-15 Reserves Volumes

A summary of the Reserves associated with the four eastern fields on both a gross and working interest basis are shown in Table 4-15. Production is assumed to end at the expiry of the subsoil contract in December 2044 or at the end of the year preceding the year of first negative EBITDA (the economic limit), whichever is earlier. In the case of 1P the economic limit is reached in December 2041, whereas for 2P and 3P reserves the expiry of the subsoil contract is earlier. These reserves are produced between 2026 until either the economic limit or the end of the field license. The sales volume gross profiles are provided below in Table 4-16.

YEAR	CONDENSATE & OIL (MMSTB)			LPG (KTONNES)			SALES GAS (BCF)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
2026	0.2	0.2	0.2	2.4	2.4	2.4	2.4	2.4	2.4
2027	2.5	2.6	2.5	35.7	35.3	36.4	35.2	34.8	35.8
2028	2.6	2.6	2.5	36.3	36.6	38.4	35.8	36.0	37.9
2029	2.7	2.6	2.5	35.4	36.5	38.8	34.9	35.9	38.3
2030	2.5	2.6	2.5	35.6	36.4	39.1	35.1	35.9	38.5
2031	1.9	2.6	2.4	31.2	36.5	39.3	30.8	36.0	38.8
2032	1.2	2.4	2.4	23.3	37.7	39.6	22.9	37.2	39.1
2033	0.8	2.2	2.4	20.0	39.2	39.9	19.7	38.6	39.3
2034	0.6	1.8	2.3	15.8	36.2	40.6	15.5	35.7	40.0
2035	0.4	1.3	2.0	12.7	29.8	38.5	12.5	29.3	38.0
2036	0.3	1.0	1.8	9.4	25.7	34.7	9.2	25.3	34.2
2037	0.3	0.8	1.6	10.3	22.6	31.5	10.2	22.3	31.0
2038	0.2	0.7	1.4	8.3	18.8	28.7	8.2	18.5	28.3

YEAR	CONDENSATE & OIL (MMSTB)			LPG (KTONNES)			SALES GAS (BCF)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
2039	0.2	0.6	1.3	6.4	15.1	29.4	6.3	14.9	29.0
2040	0.1	0.5	1.1	7.4	12.3	25.6	7.3	12.1	25.2
2041	0.1	0.4	0.9	6.6	12.6	21.9	6.5	12.4	21.6
2042	0.0	0.3	0.8	0.0	11.6	20.0	0.0	11.4	19.7
2043	0.0	0.2	0.8	0.0	8.6	18.5	0.0	8.5	18.2
2044	0.0	0.2	0.7	0.0	6.3	17.9	0.0	6.2	17.7

Table 4-16 Gross Sales Volume Profiles

4.8.6 Economic Evaluation

The Net Present Values (NPV) and Internal Rate of Return (IRR) of future cash flows derived from the extraction of the Reserves are tabulated below in Table 4-17. The values stated are net to Nostrum's interest after deduction of costs and taxes. It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets. The NPVs and IRRs do not include Nostrum's outstanding liabilities/assets at the evaluation date, and do not relate to the actual dividend stream that may accrue to shareholders.

NPV10 ($USMM) AND IRR OF RESERVES NET TO NOSTRUM (WI 80%)			
The Four Eastern Artinskian Fields	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE
NPV(10) US$MM	108.0	196.8	237.6
IRR % (NET)	26.4%	33.3%	33.8%

Table 4-17 Nostrum Project NPV(10) and IRR (Net)

5 KAMENSKOYE FIELD

5.1 Seismic Data and Interpretation

The Kalinovski reservoir in the Kamenskoye Field is a thick carbonate-clastic sequence developed between two evaporate formations in the Lower Permian. Regionally, the reservoir was broken into numerous tilted and fractured blocks (or rafts) by movement of the underlying and overlying salt. In the hydrocarbon bearing part of the Kamenskoye field area, the reservoir appears to be a single raft with minor internal faulting, a northerly-dipping Eastern limb and a southerly-dipping Western limb. Some previous studies have considered these as two separate rafts with a central non-reservoir segment. There is limited data to support one interpretation over the other. Xodus reports volumes separately for the three segments and considers a development plan with wells placed in each of the three sectors to mitigate this uncertainty.

The top Kalinovski is relatively easy to follow in the 3D seismic because of the good quality of the seismic data (3D KTTT), the robust seismic-well correlation and the continuity of the reflector, as shown in Figure 5-2. However, it presents some challenges due to poor image and discontinuity in the reflectivity in some areas which is likely a result of the complexity of the salt movement and displacement of the carbonate blocks. This salt intrusion also represents a challenge for depth imaging and correction of salt velocities which can interfere in the correct depth imaging of the Kalinovski structure. The base of the carbonate reservoir was interpreted by Nostrum following the seismic and tying to well tops, however, other internal layers were interpolated using well tops and trends. On average, the Kalinovski thickness is about 130 m, varying from 100 to 180 meters in different areas.

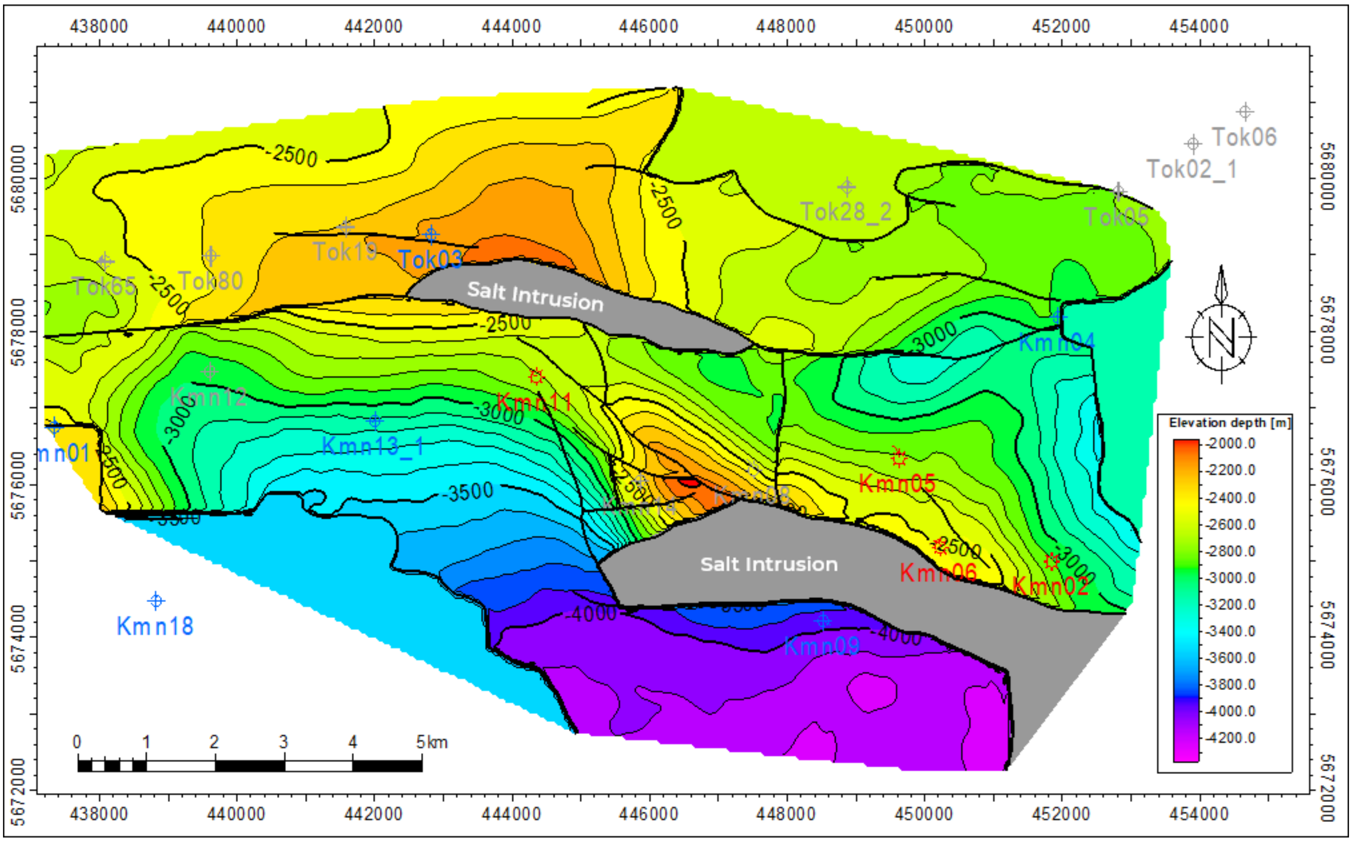


Figure 5-1 Kalinovski horizon, P2kl

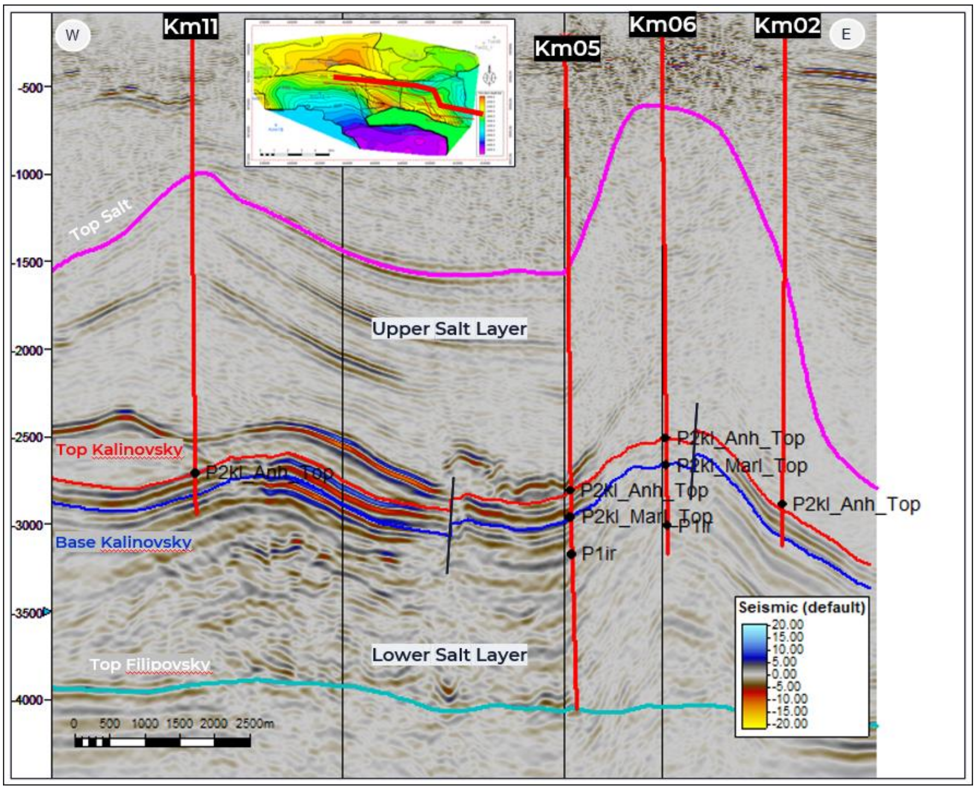


Figure 5-2 Seismic Section showing Kalinovski intra salt formation (red) along discovery wells of the Kamenskoye Field

5.2 Petrophysics

5.2.1 Core Studies

A comprehensive (for the period) special core analysis was performed on Kalinovski core data including digital microscopic photos, luminophore impregnation fracture analysis on cube shaped samples, XRD lithology as well as standard core measurements such as bulk and matrix density, lithological descriptions, calcimetry, porosity and permeability.

The fracture and pore structure study were performed by VNIGNI (Russian Research institute) in 1990 and included the detailed analysis of fracture network using the technique developed in the early 1980 by VNIGNI. The analysis workflow includes soaking the cube-shaped core samples in luminophore fluid and photography of the cube surfaces under UV light. The open fractures invaded with the fluid are represented by the bright objects in the photograph, allowing the image-based evaluation of the fracture density in different directions and fracture aperture based on the scaled size of the bright areas of the core cube (Figure 5-3).

Note that the measurements are made in ambient conditions and the fracture properties are affected by the lack of the net confining stress. Another factor affecting the fracture data based on core is that the big open fractures are underrepresented in the recovered core due to bad recovery in heavily fractured intervals.

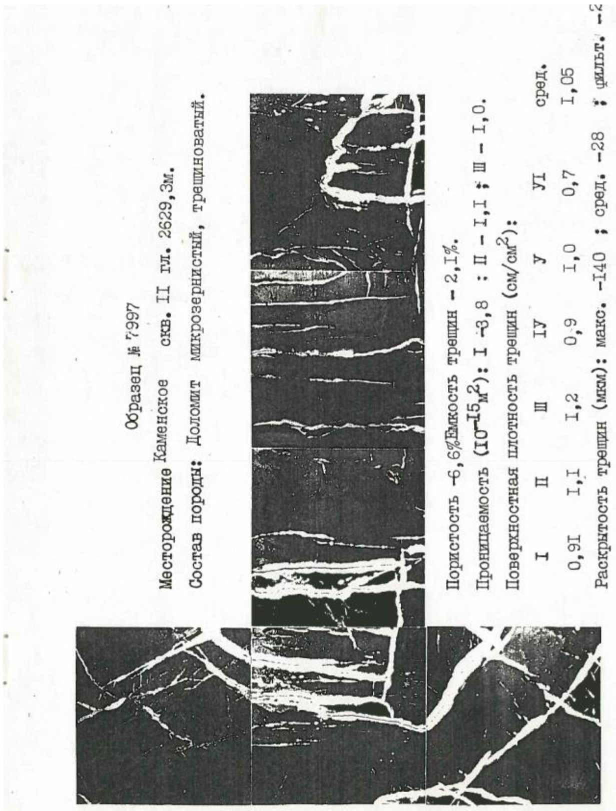


Figure 5-3 Luminophore soaking technique results example

Thin section analyses (Figure 5-4) and rock typing was also performed on Kalinovski core samples and integrated in 1996 Reserves submission report and later PM Lucas studies.

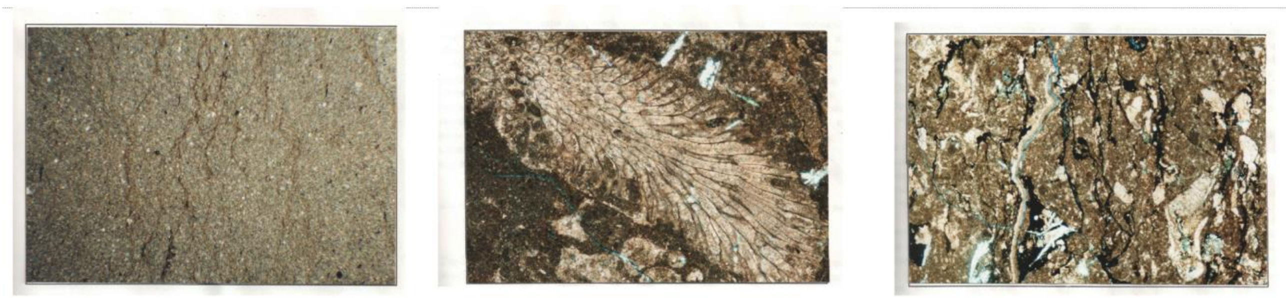


Figure 5-4 Thin section image examples

Based on lithology descriptions and XRD analysis, the EOD of the Kalinovski formation was described in the 1996 Reserves report and confirmed by PM Lucas in core studies review document (745-CDA-SSE-20006).

Kalinovski horizon is a lithologically complex, carbonate-clastic horizon resting on Ufimian terrigenous-halite deposits. The lowermost part is built up of a clastic parasequence, which thickens in northward direction toward basin's margin. The clastic wedge is a result of a complete evaporate drawdown marking the end of Ufimian times (drying out of at least basin margins), *when clastic sedimentation was established (proluvial and Aeolian deposits). Soon after evaporate drawdown, the basin was flooded by marine transgression. Clastic sediments making the foundations to Kalinovski carbonates show a clear fining upward Gama Ray (GR) log pattern indicating relative water level riseup of a clastic parasequence, which thickens in northward direction toward basin's margin. The clastic wedge is a result of a complete evaporate drawdown marking the end of Ufimian times (drying out of at least basin margins), when clastic sedimentation was established (proluvial and eolian deposits). Soon after evaporate drawdown, the basin was flooded by marine transgression.* (Page 473 PML Report)

All existing reports and studies reach the very similar conclusion that the reservoir properties of Kalinovski carbonate reservoir rocks are controlled by the lithology and secondary dolomitization and fracturing in all lithology types.

Dolomites are characterised by the highest matrix porosity with some exceptions where the dolomitization process did not result in intergranular porosity development. Prediction of the vertical and areal distribution of secondary dolomite is extremely challenging given the data available. Images logs in subsequent wells may assist with the understanding which zones/areas may have been subject to a higher degree of dolomitization.

Primary porosity in Kalinovski carbonates is very poor due to micro- to fine-grained texture. As per core data it varies from 0.1 to 11.8%. According to Report on reserves (1996), average porosity (without effective porosity cut-off applied) per carbonate lithotypes are:

- dolomites: 3.6%,
- limestone-dolomites: 2.4%,
- limestones: 1.3%.

Porosity-permeability plot reveals the general reservoir rock classification pattern:

> Most of the reservoir core datapoints fall into unclassified (using Lucias classes) area and the permeability is driven by fracture presence independent of the matrix porosity, the Classified, “conventional” poro-perm trends occurring almost exclusively in porous dolomites.

5.2.2 Formation Evaluation

The formation evaluation methodology for Kamenskoye was the same as that for the four eastern Artinskian Fields and is documented in Section 4.2.2.

5.3 Field specific geology and Static Model

Kamenskoye is the only field in the Stepnoy Leopard license to have encountered hydrocarbons in the Upper Permian Kalinovski reservoir and is located at the extreme western end of the Stepnoy Leopard chain of fields. The Kalinovski is a lithologically complex, carbonate-clastic sequence, developed between two evaporite formations. The Kalinovski is composed of mainly dolomites, formed through the process of early diagenetic dolomitization of lime muds under evaporitic conditions. The basal clastic unit is heterogenous and comprises carbonate and siliciclastic lithologies, interpreted to have been deposited during a drying out of the basin margins due to evaporation. Subsequent marine transgression initiated the deposition of carbonates, with the Kalinovski carbonates being deposited in a shallow marine shelf environment, behind a shelf-edge reefal system/bioherm (Figure 5-5).

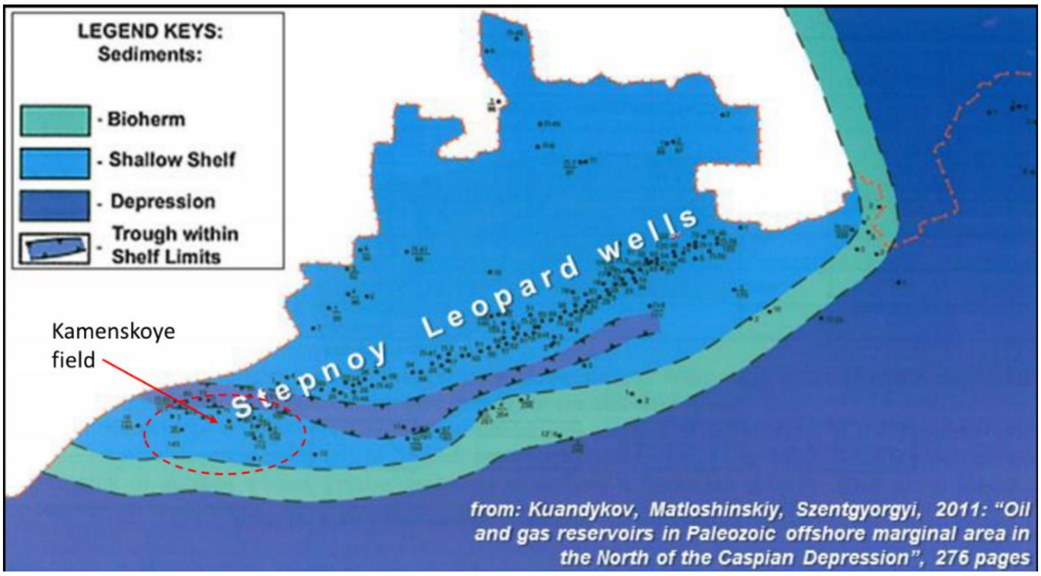


Figure 5-5 Depositional Setting of the Kalinovski, from Report: 956-GG-REP-0002

As discussed in Section 5.2, matrix porosity and permeability are very low. However, core and well test data indicate that the Kalinovski is fractured, and that the fractures provide most of the effective permeability.

The Kalinovski is developed between two thick salt deposits, as a result of deformation of these units (halokinesis), the Kalinovski was formed into structural traps and the intensive fracturing caused the enhancement of its reservoir properties (Figure 5-6).

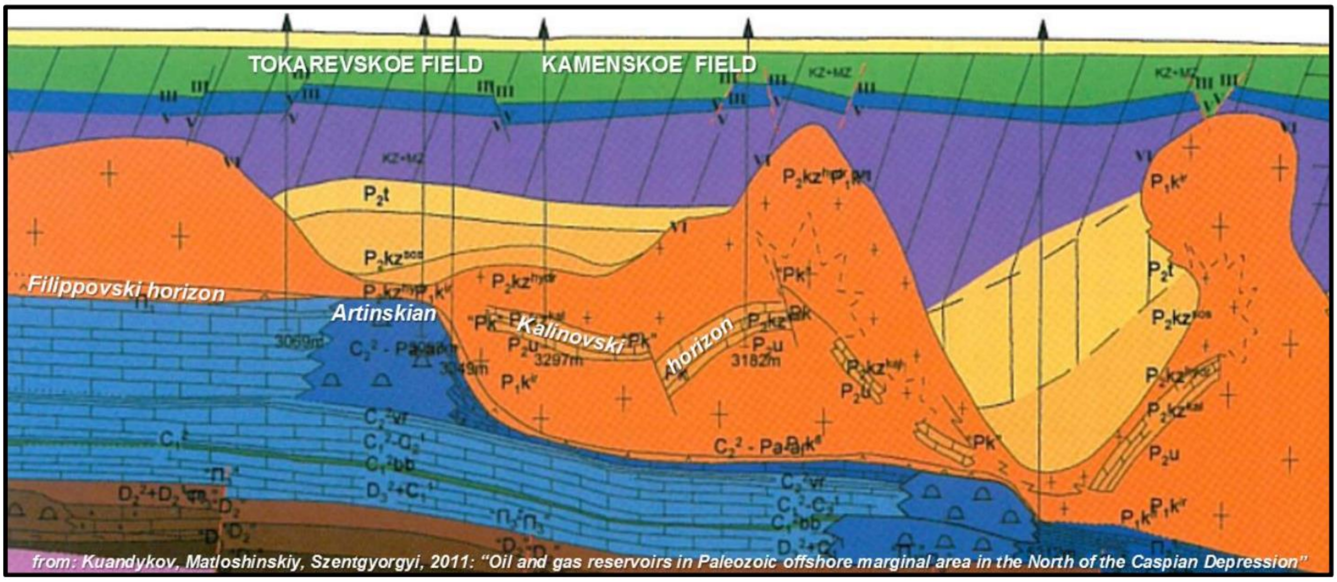


Figure 5-6 Schematic cross-section through western Stepnoy Leopard, showing structural setting of the Kalinovski from Report: 745-GMR-GEO-SSE-20115_B (PM Lucas)

Macro-fractures are observed intersecting core cubes, but are not wholly contained within them, so their length is difficult to predict, but based on their aperture, they can be expected to be dm-m scale. Meso-fractures are observed within core cubes, and are of mm-cm scale length. Micro-fractures are observed in thin sections and are of μm scale. These sets combine to give a locally pervasive fine fracture system (including fracture-related vugs) with a chaotic habit (i.e. no preferred orientation) and can be variably open or filled. Fractures at all scales occur throughout the reservoir section, including the clastic section and are not limited to a particular zone. Based on the available well data it appears there is a higher proportion of open fractures in the eastern area of Kamenskoye, compared to the centre and west.

Most of the samples fall into Lucia's "unclassified" domain, supporting the interpretation of intensively fractured rocks, where permeability is dominated by fracture presence, largely independent of the matrix. Without image logs and/or full bore core measurements is it impossible to predict the nature of any localised large fractures or fracture systems. From analysis of caliper logs and wellbore washouts it is evident that these do exist within the Kalinovski, but there is not sufficient data available to reliably characterise these features.

Nostrum built a suite of static models of the Kalinovski reservoir for the Kamenskoye field in 2024. Xodus has received copies of the models and documentation which have been reviewed as part of this CPR.

Nostrum built a single structural model using the top and base Kalinovski and a top clastic unit surface as described in Section 5.1. Well logs and tops were used from the 15 Kamenskoye wells, although no logs are available in Kmn-14 and only the upper part of Kmn-11 has log coverage. Nostrum further identified four zones within the carbonate sequence, which were used to subdivide the reservoir model (Figure 5-8). The cells are 50m x 50m x 2.5m (5m thick in the clastic zone). The model contains a number of faults as shown in Figure 5-7.

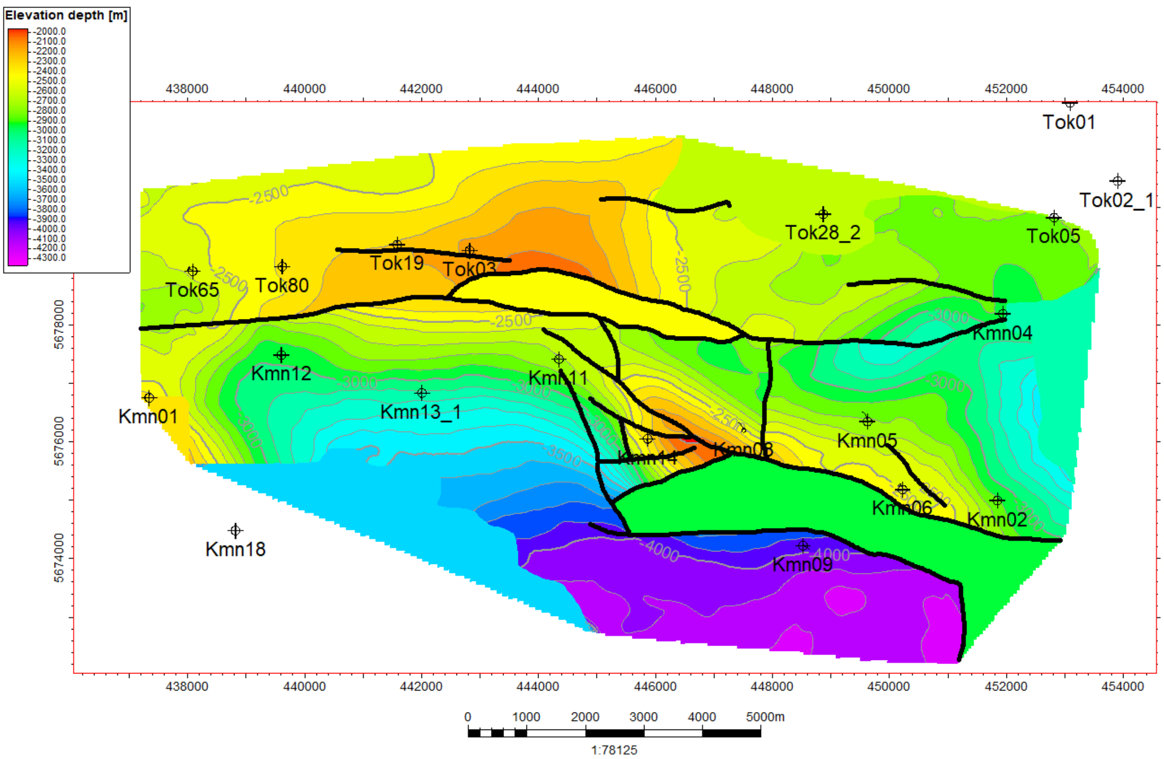


Figure 5-7 Top Kalinovski Depth Map with Faults

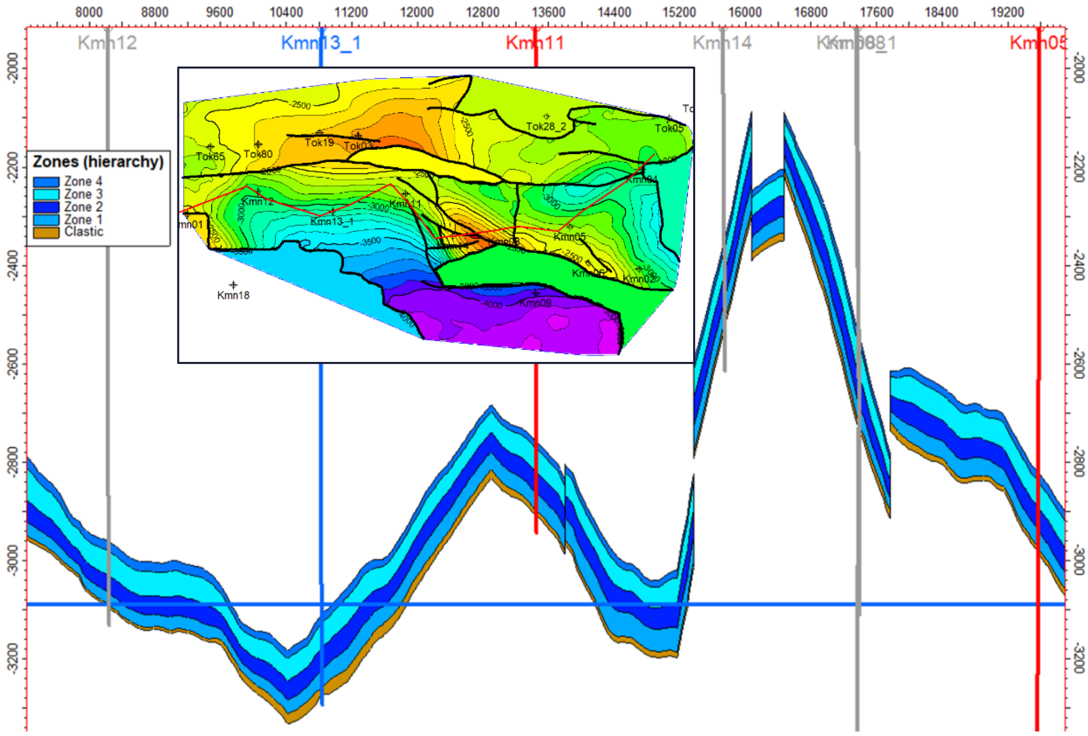


Figure 5-8 W-E Cross-Section showing model zonation in Kamenskoye across the centre of the field (inset map shows location of cross-section line in red)

Nostrum opted not to build a DFN (Discrete Fracture Network) model because of the lack of reliable data to characterise the fractures, and instead focused on capturing the diffuse small-scale fracture network using the available core data. A fracture likelihood property was created from the available core and well test data, which indicates fewer open fractures in the crestal part of the field and in the extreme west of the field. This was modified using a distance-to-fault property giving higher fracture intensity closer to faults. This fracture likelihood property was then combined with the fracture porosity seen in the core cube analysis to generate a fracture porosity property. Porosity was modelled using PHIE upscaled from well logs and stochastically distributed into the model using the Gaussian Random Function Simulation (GRFS) algorithm and a Moving Average algorithm to create alternative scenarios for porosity distributions. The fracture porosity model was subtracted from the porosity models to give matrix porosity properties.

For each of the porosity realisations, a NTG property was created using a dual porosity cut-off. Reservoir was designated as non-net if both “total” porosity (modelled PHIE) is less that 0.04 (as for the Artinskian) and fracture porosity is less than 0.004 (allowing interconnected fractures with low matrix porosity to contribute). The cut-offs were varied as part of the uncertainty analysis.

Sw in the fracture porosity was modelled as a constant of 0.1. Sw in the matrix was modelled using functions relating Sw and porosity based on the core data.

Limited reliable data is available on the GWC, so the range of contact is defined from highest known water (HKW) and lowest known gas (LKG). The contacts are summarised in Table 5-1.

	GWC /m TVDSS	
Low Case (LKG)	-3054	Test interval in Kmn-02 (flowed gas)
Mid Case	-3089	Midpoint between LKG and HKW
High Case (HKW)	-3124	Top of test interval in Kmn-13_1 (flowed water)

Table 5-1 Range of GWC for Kamenskoye

Using the core cube data and conventional core analysis, Nostrum defined two poro-perm trends: one for matrix permeability (the yellow line on Figure 5-9) and one for fracture permeability (the grey line on Figure 5-9). Nostrum then applied these poro-perm transforms to the porosity properties for matrix and fracture porosity respectively, and combined them to give an overall model permeability.

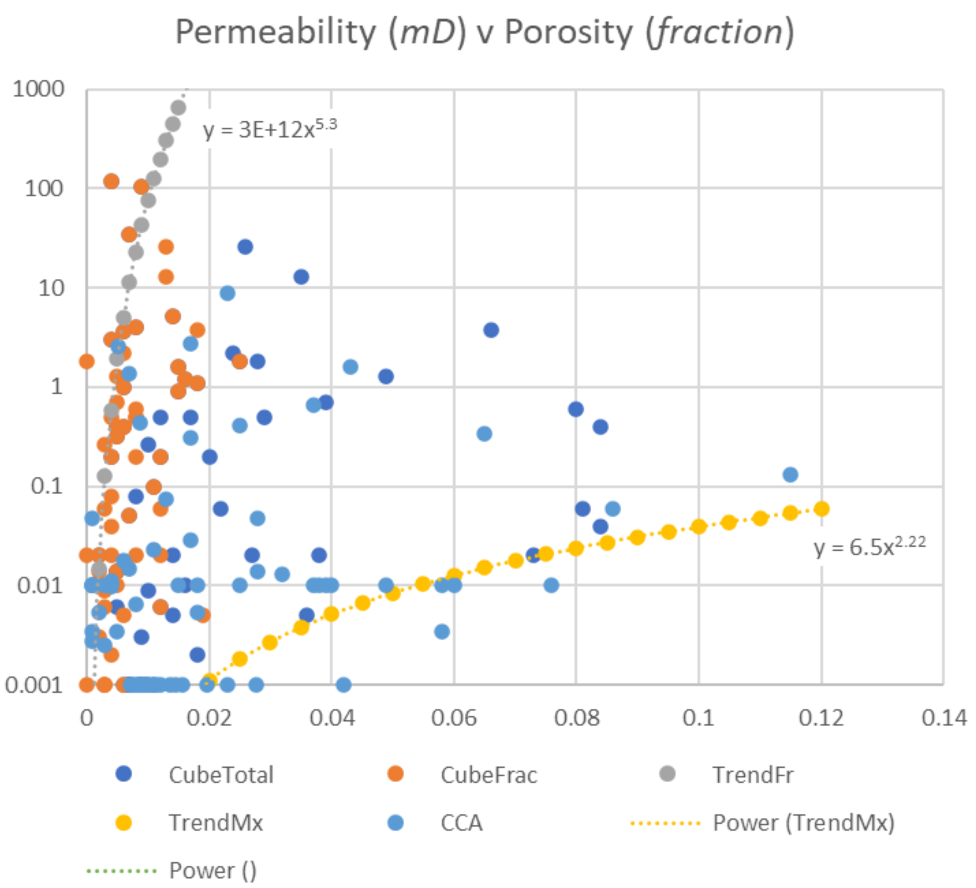


Figure 5-9 Porosity-Permeability Cross-plot for conventional core analysis and core cube data

An uncertainty workflow was run to determine the P90, P50 and P10 volumetric cases. This incorporated variables for porosity, GWC, fracture proportion, fracture porosity cut-off (for NTG determination) and Bg. In total 600 cases were run, and the outputs sorted by GIIP. P10, P50 and P90 cases were selected for dynamic simulation.

Xodus has some reservations about the modelling approach, particularly with regards to the averaging of porosity and permeability across the field. This has the effect of homogenising the reservoir properties, particularly so given that the porosity will be dominated by the matrix and the permeability will be dominated by the fractures. This is not fully represented in the suite of models provided. Consequently, Xodus calculated gas in-place using an analytical approach based on GRVs from seismic data and reservoir properties from the wells directly and used this for volumetrics.

5.4 In place Volumes and Uncertainty

Xodus conducted an independent assessment of the GIIP for the Kalinovski reservoir at Kamenskoye and compared this to the GIIP ranges from the Nostrum 2024 static model. Xodus used Crystal Ball to run a Monte Carlo simulation to assess the range of GIIP. The simulation was run 10,000 times, with inputs and resulting volumes being separated into the three segments (East, Central and West) as shown in Figure 5-10 and separated by type: fractures and matrix (including the basal clastic unit). These were summed probabilistically to obtain the total GIIP.

GRVs were calculated using a range of GWCs 3054m – 3089m – 3124m (as used by Nostrum and explained in Table 5-1) to represent the full range from HKW to LKG, additionally a +/-15m variation in reservoir thickness was used to represent the structural uncertainty. The same GRV range was used for the fractures and matrix, and these were given a correlation factor of 1, so in a given Monte Carlo run, the same GRV value was used for fractures and matrix.

For the petrophysical ranges, wells were grouped as follows:

- Eastern segment: Kmn-02, -04, -05 and -06
- Central segment: Kmn-08
- Western segment: Kmn-01, -11, -12 and -13

No systematic difference was found between the properties of the 4 zones identified by Nostrum, nor between the matrix properties of the carbonates and the clastics, so the same properties ranges were used across all zones within a segment.

Porosity ranges for the matrix were calculated from the average PHIE in the well log interpretation. NTG ranges were calculated from the average NTG in the well log interpretation for a range of cutoff values (2-4-5%). Sw was calculated using a range of saturation functions. Given the high degree of uncertainty in Sw calculation from wireline logs in these reservoirs, saturation functions from both the Kalinovski and the Artinskian were used to ensure a realistic range of Sw uncertainty was captured. Matrix porosity and Sw were negatively correlated (i.e. low matrix porosity corresponds to high Sw). The range of petrophysical inputs for the matrix used for each parameter is shown in Table 5-2.

For the fractures, a constant NTG value of 1 and a constant Sw value of 0.1 were used. The porosity range used was 0.2-0.4-0.6%. The core data suggest a fracture porosity average of 1%, but based on our experience of fractured carbonates, this is considered over-optimistic. It should also be remembered that the core measurements of fracture porosity are made at ambient conditions, so corrections need to be made for in-situ conditions (see Section 5.2.1), thus a lower range of porosity than that reported from the core measurements is used.

The resulting range of GIIP is shown in Table 5-3 (note the total is a probabilistic sum, rather than an arithmetic sum) and visually in Figure 5-11.

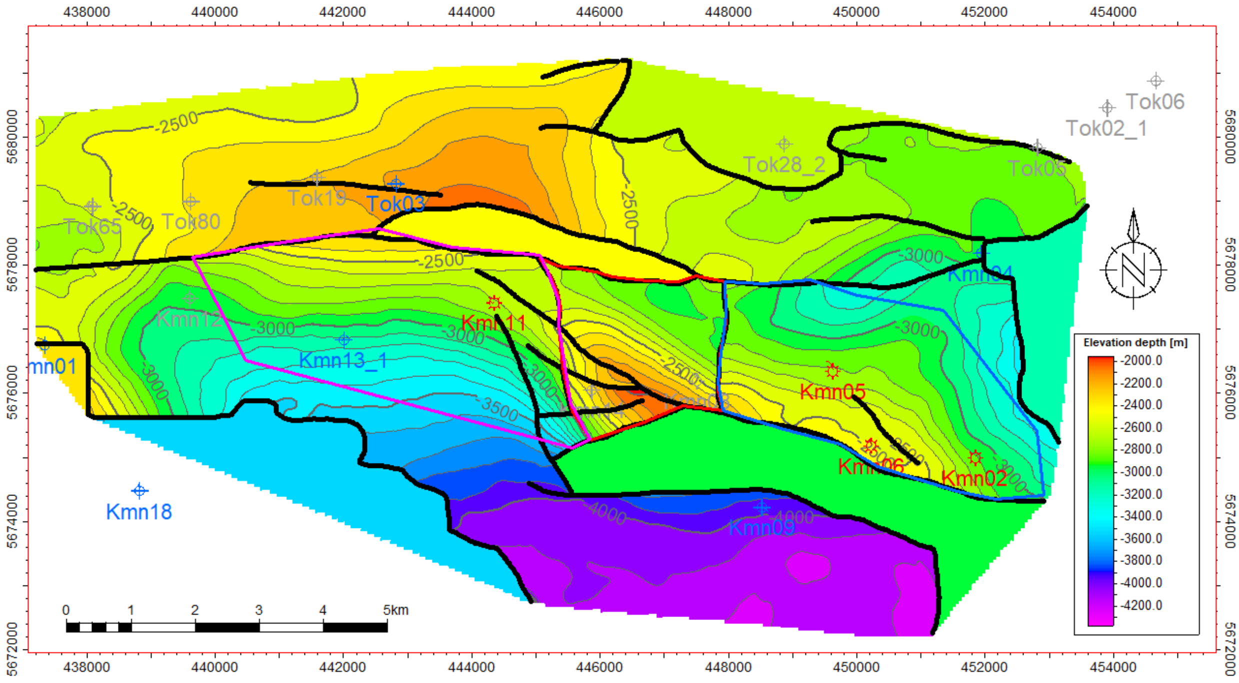


Figure 5-10 Top Kalinovski Depth Map showing the polygons used for Xodus' Volumetric Calculation (Blue=East, Red=Central, Pink=West)

MATRIX (INCLUDING CLASTICS)		NTG	POROSITY	SW
West	Low	0.062	0.034	0.448
	Mid	0.101	0.050	0.315
	High	0.332	0.057	0.182
Central	Low	0.012	0.029	0.503
	Mid	0.025	0.052	0.337
	High	0.255	0.062	0.171
East	Low	0.222	0.043	0.377
	Mid	0.377	0.054	0.275
	High	0.681	0.061	0.173

Table 5-2 Range of Petrophysical Inputs for GIIP Calculation (Matrix inc. Clastics)

RESERVOIR TYPE	GIIP /BCF		
	P90	P50	P10
Fractures	82.03	118.61	160.46
Matrix (inc. Clastics)	186.50	311.39	517.85
TOTAL	306.39	435.57	635.06

SEGMENT	GIIP /BCF		
	P90	P50	P10
West	64.26	118.82	193.05
Central	35.75	60.85	99.12
East	149.12	243.15	416.12
TOTAL	306.39	435.57	635.06

Table 5-3 Range of GIIP for Kamenskoye (by reservoir type and by segment)

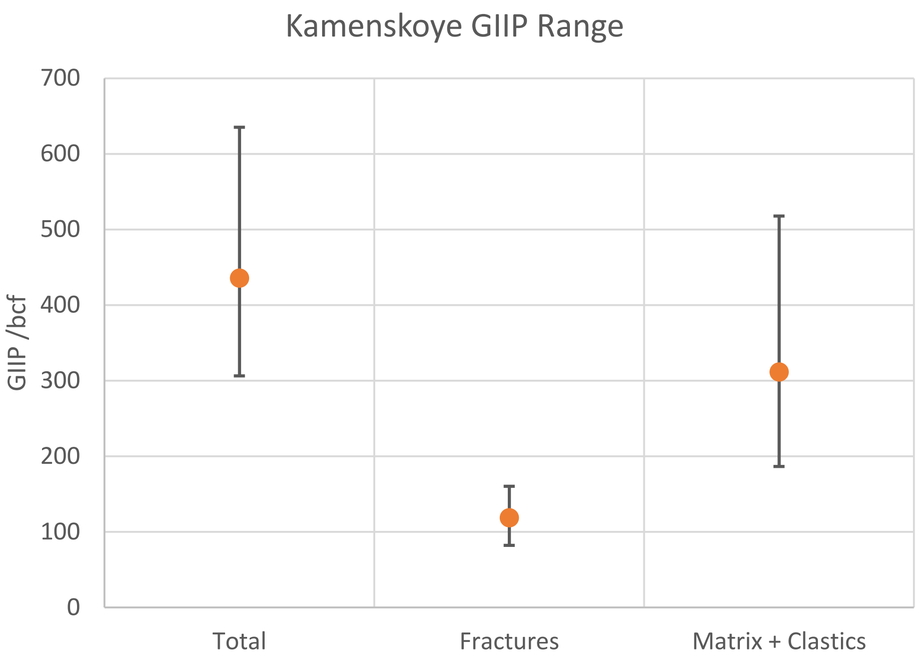


Figure 5-11 Range of GIIP for Kamenskoye

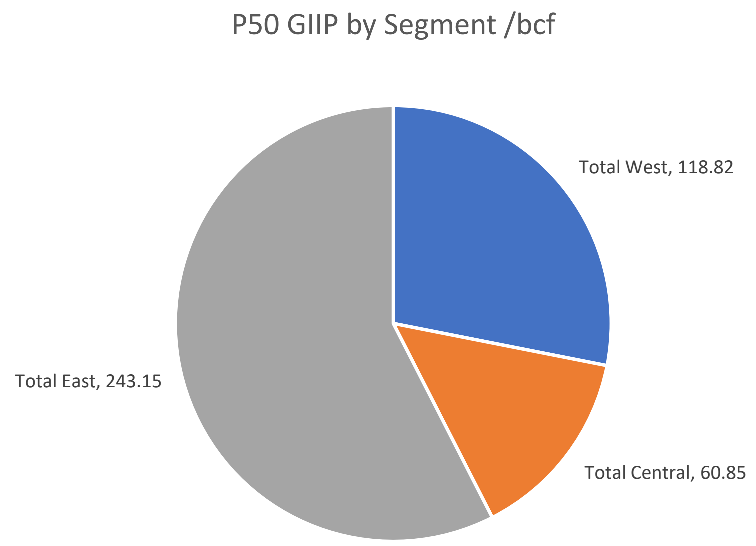


Figure 5-12 Xodus P50 GIIP by Segment

As expected, the majority of the GIIP (65%) is contained in the matrix, with over half the total GIIP (57%) in the eastern segment (Figure 5-12) as a result of the better reservoir properties in this segment. The GRV of the eastern and western segments is very similar.

5.5 Dynamic Model and Recoverable Volumes

The development of the Kamenskoye field is not being considered on a standalone basis and production will only commence once suitable ullage is available in the 14" trunkline from the eastern fields. Therefore, whilst costs and production for Kamenskoye are estimated independently to the eastern fields, they should be considered as a single development project. This means Reserves are not calculated for Kamenskoye alone, but only combined with the eastern fields.

Xodus has however calculated technically recoverable resources for Kamenskoye, based on Xodus' independent calculation of in-place volumes and recovery factors derived from Nostrum's reservoir model and development plan outlined in the Kamenskoye Dynamic Modelling Report[2], adjusted to match recovery factors from analogue fields.

This development plan consists of 5 vertical producers drilled to maximise gas recovery in the reservoir. It is assumed the wells are placed structurally high and in the areas of highest permeability-thickness as estimated from the historical well test results for the field as shown in Figure 5-13 and Figure 5-14.

[2] *Filenote: Stepnoy Leopard Kamenskoye Field Dynamic Modelling Report*

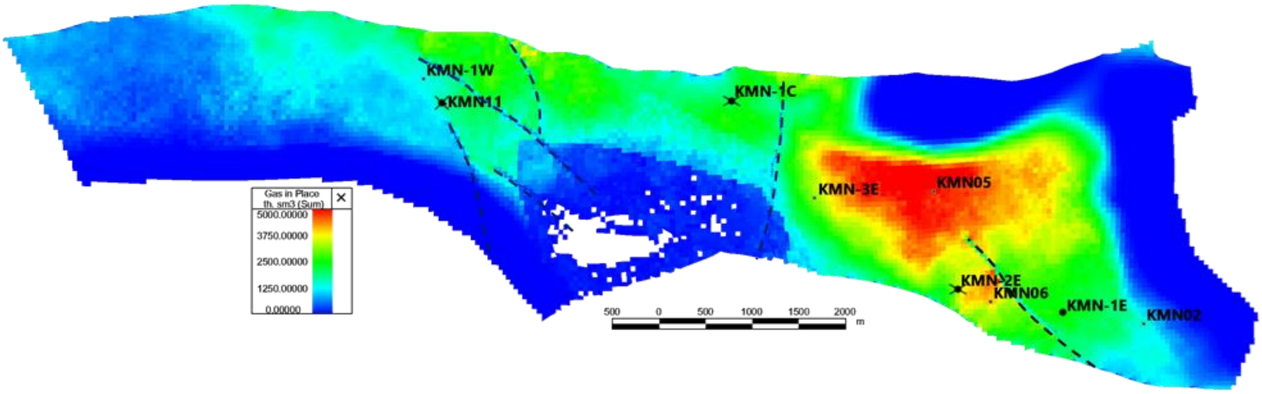


Figure 5-13 - Kamenskoye P50 Gas In-place Map

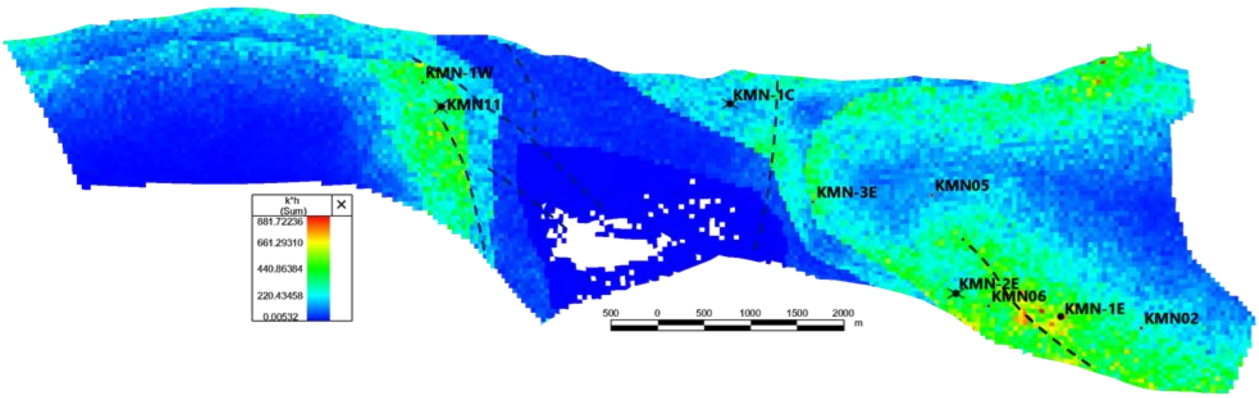


*Figure 5-14 - Kamenskoye P50 k*h Map*

Based on historical well test results, the Eastern panel has reliable reservoir productivity with tests carried out on Kmn2, Kmn5 and Kmn6 which had gas rates varying between ~10 and 50 mmscf/d. Kmn11 in the Western panel is reported to have flowed at even higher rates, but based on the PML report 745-WTI-RE-SSE-20033, the Kmn-11 test results are viewed as having questionable reliability.

The central panel had one flow test from Kmn8, which flowed low rates of water.

Based on these results Nostrum plan three wells in the eastern panel, one well in the central panel and one well in the western panel.

Xodus has reviewed the dynamic model build assumptions and the production forecasts generated by the model.

Overall, the Nostrum dynamic model assumptions and development plan are reasonable given the natural uncertainty and reliability of the historical data. However, Xodus' opinion is that the assumed Nostrum well count and associated recovery is optimistic. Hence based on the Xodus EUR per well benchmarking (described below) and the Xodus estimated GIIPs that are less than Nostrum, the well count and profiles generated by Nostrum's simulation model have been adjusted.

			By 01/01/2045	By 01/01/2045
Case	Nostrum Well Count (East/Central/West)	Xodus Well Count (East/Central/West)	Xodus Produced (Raw) Gas (bcf)	Nostrum Produced (Raw) Gas (bcf)
P90	5 (3/1/1)	6 (5/0/1)	~147	~113
P50	5 (3/1/1)	7 (4/1/2)	~168	~144
P10	5 (3/1/1)	6 (4/0/2)	~177.5	~177.5

Table 5-4 - Nostrum vs. Xodus Kamenskoye Well Count / Volumes Produced Comparison

For the P90 and the P10 Xodus cases the central panel is viewed as much higher risk relative to the GIIP available at lower risk in the Eastern and Western panels, and hence in the Xodus cases priority is given to adding additional wells in these panels.

The Kamenskoye profiles were adjusted for system uptime as follows:

P90 / P50= 95%

P10 = 98%

This is based off the operating statistics achieved at Nostrum's Chinarevskoye Operations.

As described in Section 5.1, the Kalinovski reservoir is composed of carbonate rafts which are both underlain and overlain by Kungurian salt, as well as being compartmentalised. This implies that it is highly likely that the reservoir in Kamenskoye is isolated and sealed in all directions, and therefore unlikely to be in contact with any significant aquifer. Hence CAPEX for management and mitigation of premature water breakthrough is not deemed necessary for the Kamenskoye development.

Condensate recovery factors have been assumed to be half of those for the gas. These resources are shown in Table 5-5.

KAMENSKOYE TECHNICAL RESOURCES	GAS /BCF			CONDENSATE /MMBBL		
	P90	P50	P10	P90	P50	P10
Recovery factor (%)	65	75	80	32.5	37.5	40
Resources (BCF	199	327	508	0.70	2.37	5.59

Table 5-5 Kamenskoye technically recoverable resources

Xodus has used in-house knowledge and data to obtain analogues for the Kamenskoye field area in Kazakhstan, see Figure 5-15. These analogues help support the recoverable ranges that we would expect from similar settings to the Kamenskoye field. Representative analogues are mainly onshore in Poland and Germany where Permian Zechstein Carbonates within the Zechstein salt formations are developed. The style of these plays are close geological analogues to the Kalinovski reservoir in Kamenskoye.

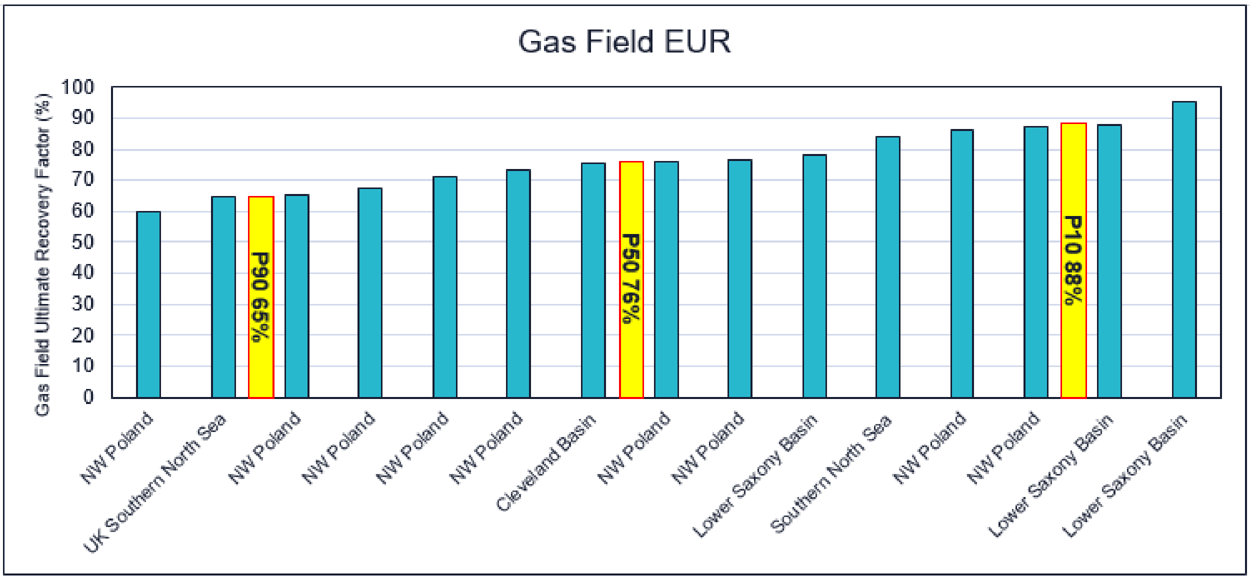


Figure 5-15 Recovery factors from analogue fields for Kamenskoye

5.6 Development Plan

5.6.1 Facilities and Infrastructure Overview

The Kamenskoye field, like the Eastern fields, is planned to be developed on a Full Gas Blowdown basis, consisting of raw gas-condensate production from 7 wells (P50) (6 wells in P90 and P10 cases) being sent via a gathering system / 10" trunkline which will tie-into the western end of the Eastern field 14" trunkline. The Kamenskoye fluids will therefore be comingled with the Eastern field fluids and sent via the pressure booster compression and inter-field pipeline to the existing processing facilities at the Chinarevskoye field to be de-sulphurised and the condensate, LPG and sales gas will be produced. Kamenskoye production will therefore not commence until suitable ullage becomes available in the Eastern field 14", trunkline, pressure-booster compression and inter-field pipeline.

A development concept schematic showing the Kamenskoye field gathering system and the West trunkline connection to the East trunkline is shown in Figure 5-16. Figure 5-16 shows a typical 3 well arrangement for Kamenskoye. Additional wells will be configured and connected to the West trunkline in the same way.

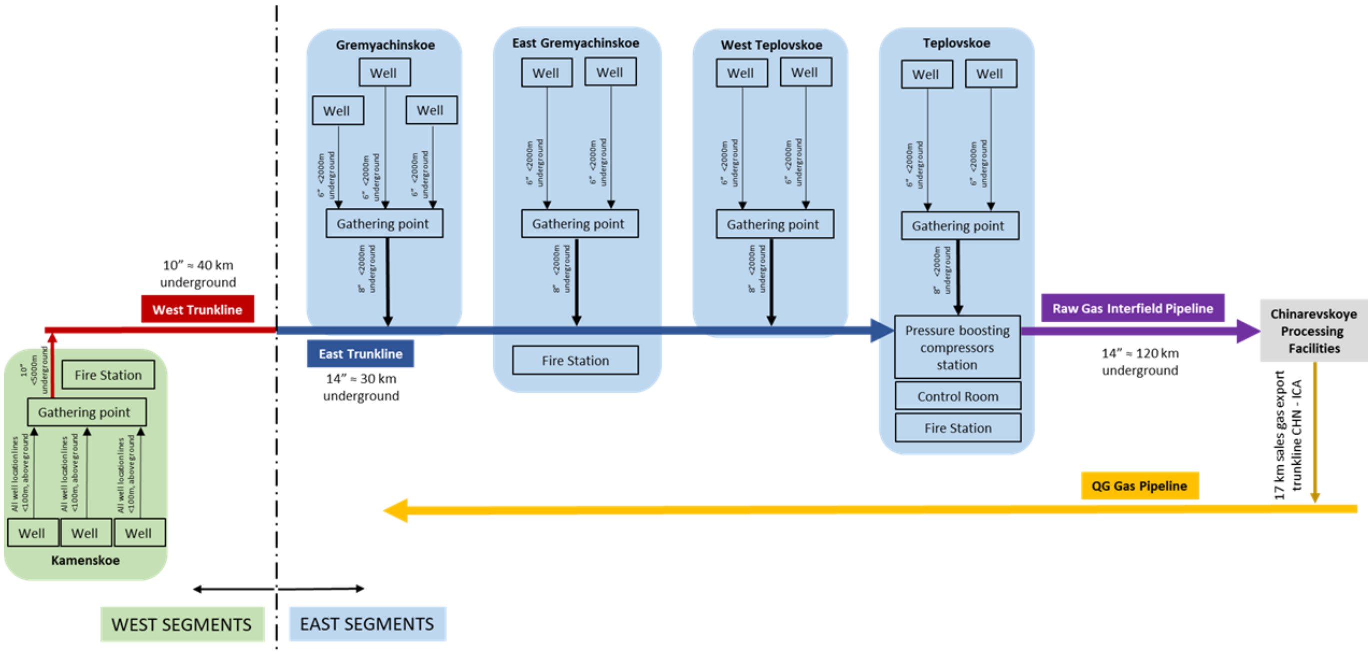


Figure 5-16 Kamenskoye Development Schematic

5.6.2 Product Yields

In order to determine the product yield rate for the Kamenskoye field, Nostrum performed HYSYS process simulation modelling of the surface facilities using the estimated composition of the produced Kamenskoye fluids to determine the product rates. Subsequently, Nostrum revised their composition estimate for the produced fluids and recalculated the likely impact on the product rates (and hence yield rates) based on the change in component mass flows of the produced fluids. Xodus has not checked the original simulations or the subsequent calculations, but the methods used to determine the yield factors appears reasonable. The yield factors provided by Nostrum for each product stream are shown in Table 5-6.

PRODUCT	YIELD FACTOR (%)
Condensate (factor to oil production)	75.9
LPG (factor to gas production)	0.0034
Sales Gas (factor to gas production)	94.9

Table 5-6 Eastern Segments Yield Factors

5.7 Costs

Xodus has reviewed the latest Nostrum Capital Expenditure (CAPEX), Operating Expenditure (OPEX) and Abandonment Expenditure (ABEX) assumptions and plans for the 7 well development (P50) programme for the Kamenskoye field. These are discussed separately below.

5.7.1 CAPEX

Nostrum has developed their cost estimate using a combination of early phase engineering (i.e. preliminary route selection from 2018 for the west trunkline) and use of historical norms e.g. standard well-site configurations at the Chinarevskoye (CHN) field, and historical norms for flowlines in locations with similar topography.

Drilling and Wells

Nostrum is planning a 7 well development (P50) with drilling for the initial 4 wells due to take place across 2032 and early 2033. First gas is targeted for May 2033 once ullage becomes available in the Eastern field 14"NB trunkline and 14"NB inter-field pipeline. The additional 3 wells are targeted to be drilled in late 2034 and early 2035.

For the P90 case, a total of 6 wells are planned, with the initial 4 due to be drilled in 2030 and the remaining 2 in the second half of 2032. Again, first gas will be targeted for when ullage becomes available, which for P90 is expected in January 2031.

For the P10 case, a total of 6 wells are also planned, with the initial 4 due to be drilled starting in December 2033 and the remaining 2 starting in June 2037. Again, first gas will be targeted for when ullage becomes available, which for P10 is expected in December 2034.

Xodus reviewed the CAPEX estimate for the drilling programme and considers the majority of the costs to be reasonable. The well costs are based on current rig market rates and historical Chinarevskoye drilling and completion durations. Xodus has included a 10% incremental contingency for rig mobilisation and supporting costs to align with the 10% contingency included for each well in the drilling costs provided by Nostrum. The impact on the overall Drillex estimate is shown in Table 5-7.

CASE	NOSTRUM COSTS	CONTINGENCY ADDED	TOTAL
P90 & P10	$36.45 million	$153 thousand	$36.61 million
P50	$42.73 million	$199 thousand	$42.93 million

Table 5-7 Kamenskoye Drilling CAPEX

Pipeline & Surface Facilities

Nostrum provided details of their CAPEX estimates for the Kamenskoye gathering system.

Based on interviews with Nostrum personnel, Xodus were advised that the CAPEX estimate already included 10% contingency for delivery and construction activities associated with the gathering system. Xodus has allowed for 10% contingency on the support facilities, engineering design and project management costs. The impact on the overall pipeline and surface facilities estimate is shown in Table 5-9.

CASE	NOSTRUM COSTS	CONTINGENCY ADDED	TOTAL
P90 & P10	$38.00 million	$452 thousand	$38.45 million
P50	$40.00 million	$452 thousand	$40.45 million

Table 5-8 Kamenskoye Pipeline & Surface facilities CAPEX

Total CAPEX

The overall impact of the contingencies and additional facilities described in the drilling and pipeline & surface facilities above are summarised in Table 5-9. These figures also include Project Management (to which Xodus has also added 10% contingency) and other costs.

CASE	NOSTRUM COSTS	CONTINGENCY ADDED	TOTAL
P90 & P10	$79.52 million	$1.11 million	$80.64 million
P50	$88.01 million	$1.18 million	$89.19 million

Table 5-9 Kamenskoye Total CAPEX

5.7.2 OPEX

Xodus has used the latest Nostrum OPEX estimate as the basis for future field OPEX. The OPEX includes intervention costs, chemicals, maintenance, employee costs, firefighting service costs, well service engineer costs, and personnel camp cost and amounts to $35.29 million (P90) / $30.70 million (P50) / $23.73 million (P10) over the lifetime of the licence as shown in Table 5-10 to Table 5-12.

No additional processing fee is required to be paid to the operator of the Chinarevskoye processing facility for the additional volumes from Kamenskoye. Transport costs for Kamenskoye hydrocarbons are the same as in the Eastern fields.

5.7.3 ABEX

At the end of the licence period, an allowance has been made for abandoning all wells and surface facilities. Nostrum provided Xodus with detail of the estimated Abandonment Expenditure (ABEX) for the wells, well sites, flowlines/trunklines and gathering station facilities, assuming surface facilities are decommissioned and removed, with subsequent land recultivation and soil reinstatement. Xodus considers the base ABEX estimate of $5.3 million (P90 and P10 cases) and $5.85 million (P50), developed by Nostrum, to be reasonable, however, we have included an incremental 10% contingency in the total ABEX, taking the total to $5.83 million (P90 and P10 cases) and $6.44 million (P50).

5.7.4 Forecast of Costs

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2024	0	0	0	0	0

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	330	16,276	4,191	20,797	1,174
2030	23,964	18,176	924	43,064	2,012
2031	0	0	0	0	2,012
2032	10,315	3,333	385	14,033	2,110
2033	1,997	667	77	2,741	2,348
2034	0	0	0	0	2,348
2035	0	0	0	0	2,348
2036	0	0	0	0	2,348
2037+	0	0	0	0	2,348
Total	36,606	38,452	5,577	80,635	35,294

Table 5-10 Kamenskoye Field Forecast of Costs P90

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	0	0	0	0	0
2031	0	4,200	2,508	6,708	0
2032	16,306	30,252	2,299	48,857	1,845
2033	7,988	0	308	8,296	2,012
2034	4,324	1,333	154	5,811	2,040
2035	12,312	4,000	462	16,774	2,362
2036	1,997	667	77	2,741	2,516
2037+	0	0	0	0	2,516
Total	42,927	40,452	5,808	89,187	30,698

Table 5-11 Kamenskoye Field Forecast of Costs P50

YEAR	DRILLING	SURFACE FACILITIES	PROJECT MANAGEMENT & OTHER	TOTAL CAPEX	OPEX
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	0	0	0	0	0
2031	0	0	0	0	0
2032	0	0	0	0	0
2033	2,327	20,835	4,268	27,430	0
2034	21,967	13,617	847	36,431	839
2035	0	0	0	0	2,012
2036	0	0	0	0	2,012
2037	12,312	4,000	462	16,774	2,166
2038+	0	0	0	0	2,348
Total	36,606	38,452	5,577	80,635	23,273

Table 5-12 Kamenskoye Field Forecast of Costs P10

5.8 Economics

5.8.1 Methodology

The development of the Kamenskoye field is not being considered on a standalone basis and production will only commence once suitable ullage is available in the 14" trunkline from the eastern fields. Therefore, whilst costs and production are estimated independently for Kamenskoye, it should be considered as a single development project together with the eastern fields, for the purposes of Reserves and economics calculations.

As with the eastern fields alone, Reserves and Net Present Values (NPVs) have been calculated using an Excel™ economic model prepared by Nostrum of Nostrum's interest (80%) in the combined four eastern Artinskian fields and Kamenskoye field.

5.8.2 Assumptions

General assumptions used by Xodus in the economic evaluation of the combined Eastern fields and Kamenskoye field are the same as those used in the Eastern fields alone. The assumptions can be found in the following previous sections:

- General Assumptions – Page 43
- Fiscal Assumptions – Page 43

- Commodity Prices – Page 44

5.8.3 Reserves Evaluation

A summary of the Reserves associated with the combined Eastern fields and Kamenskoye field on both a gross and working interest basis are shown in Table 5-13. Production is assumed to end at the expiry of the subsoil contract in December 2044 or at the end of the year preceding the year of first negative EBITDA (the economic limit), whichever is earlier. In the case of 1P the economic limit is reached in December 2041, whereas for 2P and 3P reserves the expiry of the subsoil contract is earlier.

Reserves	Gross in the combined Eastern Fields & Kamenskoye Field			Working Interest (80%)		
	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE
Sales Gas (BCF)	408.54	620.93	779.36	326.8	496.7	623.5
Condensate and Oil (MMSTB)	16.96	26.62	34.27	13.6	21.3	27.4
LPG (ktonnes)	414.47	629.93	790.66	331.6	503.9	632.5

Table 5-13 Reserves Volumes

These reserves are produced between 2026 until either the economic limit or the end of the field license. The sales volume gross profiles are provided below in Table 5-14.

YEAR	CONDENSATE & OIL (MMSTB)			LPG (KTONNES)			SALES GAS (BCF)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
2026	0.2	0.2	0.2	2.4	2.4	2.4	2.4	2.4	2.4
2027	2.5	2.6	2.5	35.7	35.3	36.4	35.2	34.8	35.8
2028	2.6	2.6	2.5	36.3	36.6	38.4	35.8	36.0	37.9
2029	2.7	2.6	2.5	35.4	36.5	38.8	34.9	35.9	38.3
2030	2.5	2.6	2.5	35.6	36.4	39.1	35.1	35.9	38.5
2031	2.0	2.6	2.4	49.6	36.5	39.3	48.9	36.0	38.8
2032	1.3	2.4	2.4	44.2	37.7	39.6	43.6	37.2	39.1
2033	0.9	2.3	2.4	39.2	50.7	39.9	38.6	49.9	39.3
2034	0.6	2.0	2.3	30.8	57.2	41.3	30.4	56.4	40.7
2035	0.5	1.5	2.4	24.1	50.8	58.1	23.8	50.0	57.2

YEAR	CONDENSATE & OIL (MMSTB)			LPG (KTONNES)			SALES GAS (BCF)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
2036	0.4	1.2	2.1	18.2	46.7	55.9	17.9	46.0	55.1
2037	0.3	1.0	1.9	17.3	42.4	52.7	17.0	41.8	52.0
2038	0.2	0.8	1.7	13.9	35.9	49.9	13.7	35.4	49.2
2039	0.2	0.6	1.5	11.0	29.5	50.6	10.8	29.1	49.9
2040	0.1	0.5	1.3	11.1	24.2	46.8	10.9	23.8	46.1
2041	0.1	0.4	1.1	9.6	22.9	43.1	9.5	22.6	42.5
2042	0.0	0.3	1.0	0.0	20.7	41.2	0.0	20.4	40.6
2043	0.0	0.2	0.9	0.0	15.8	39.7	0.0	15.6	39.1
2044	0.0	0.2	0.8	0.0	11.7	37.4	0.0	11.5	36.8

Table 5-14 Gross Sales Volume Profiles

5.8.4 Economic Evaluation

The Net Present Values (NPV) and Internal Rate of Return (IRR) of future cash flows derived from the extraction of the Reserves are tabulated below in Table 5-15. The values stated are net to Nostrum's interest after deduction of costs and taxes. It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets. The NPVs and IRRs do not include Nostrum's outstanding liabilities/assets at the evaluation date, and do not relate to the actual dividend stream that may accrue to shareholders.

NPV10 ($USMM) AND IRR OF RESERVES NET TO NOSTRUM (WI 80%)			
THE COMBINED EASTERN FIELDS & KAMENSKOYE FIELD	PROVED	PROVED & PROBABLE	PROVED, PROBABLE & POSSIBLE
NPV(10) US$MM	120.3	220.4	267.9
IRR % (NET)	26.8%	33.8%	34.3%

Table 5-15 Nostrum Project NPV(10) and IRR (Net)

6 THE THREE WESTERN ARTINSKIAN FIELDS

6.1 Seismic Data and Interpretation

The Western fields in the Stepnoy Leopard licence are Tokarevskoye, Tsyganovskoye and Ulyanovskoye from West to East, and they are imaged by the 3D KTTT Seismic survey (Figure 6-1). The Tokarevskoye and Ulyanovskoye fields are composed of a few separated reef closures along the shelf rim, while Tsyganovskoye is a small closure positioned between them.

As mentioned for the Eastern fields in Section 4.1, the Artinskian horizon is highly variable and presents a challenge to interpret as a result of poor seismic resolution and a poor match between seismic and well data. This dataset shows more mismatch than the 3D Melovaya survey used for the Eastern fields. Examples of the Artinskian reefal fields are shown in dip seismic sections from the 3D KTTT survey in Figure 6-2. Wherever there was a poor seismic-well tie between the well tops and the seismic reflector, RES finalised the interpretation by matching horizons to well tops first and then following the seismic as much as possible. In some cases, the final surface appears to cut across the seismic reflections in order to be able to tie the wells at the crest of the reef and those in the back reef or lagoon area. This appears to be unavoidable with the data available at present and the uncertainties associated with this have been captured to a reasonable degree.

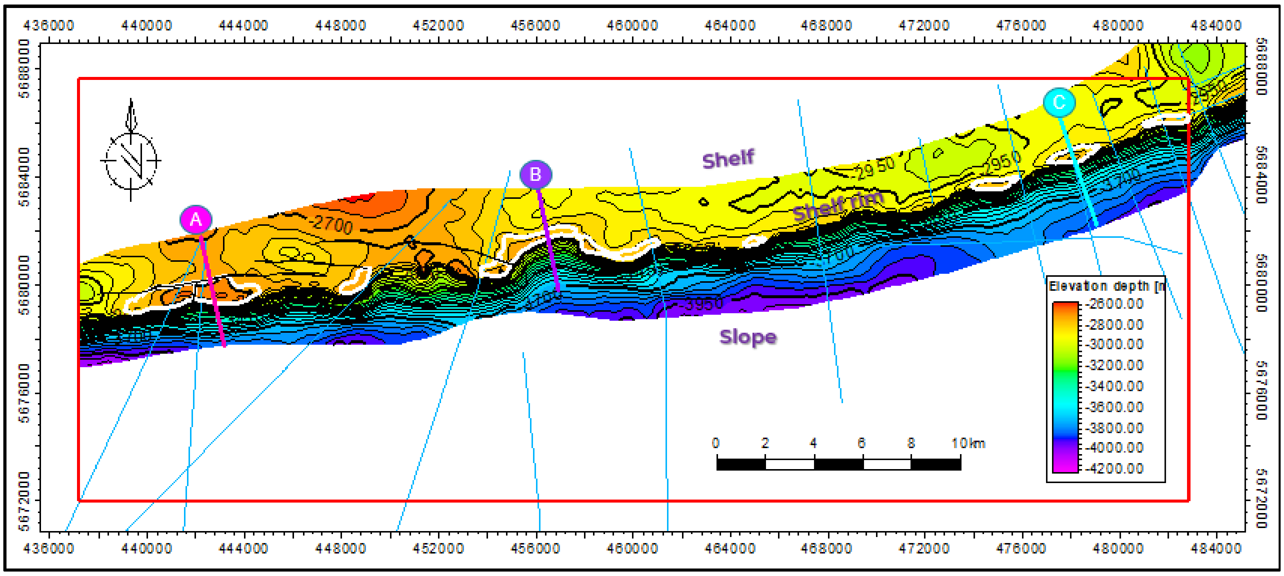


Figure 6-1 Structural Map of the Artinskian horizon (P1ar), CI=50m, 3D KTTT survey in red, 2D seismic lines in light blue and fields outlines in white. Lines A, B, C are seismic section across the fields.

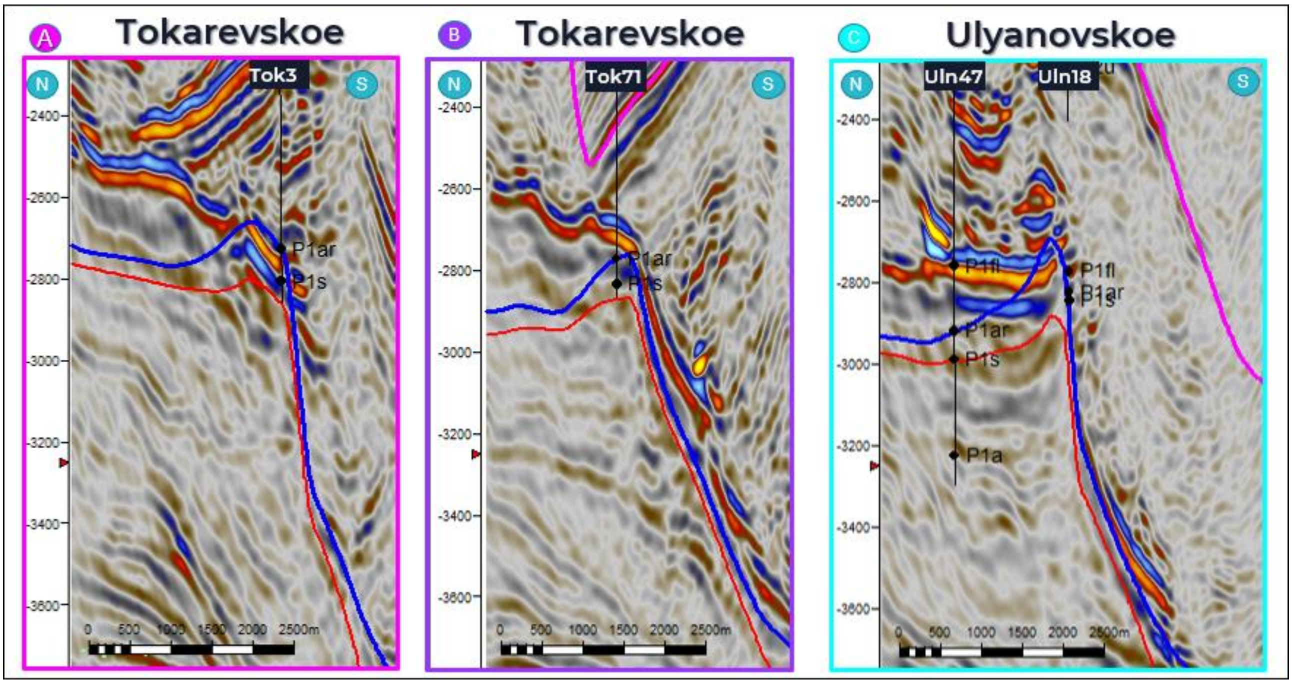


Figure 6-2 Dip Seismic Sections showing interpretation of the Artinskian (P1ar, blue) and Sakmarian (P1S, red) in different fields.

6.2 Petrophysics

Petrophysics for the Artinskian is discussed in Section 4.2. The same approach was used for the wells drilled in Ulyanovskoye, Tsyganovskoye and Tokarevskoye.

6.3 Field specific geology

The geology of the Artinskian is discussed in Section 4.3. Since well data over the three western fields is scarce in some fields/segments, this has been supplemented by using data from the four eastern fields as an analogue.

6.4 In place Volumes and Uncertainty

No static models have been built for the three western fields, so the volumes presented here are calculated using an analytical method. Xodus conducted an independent assessment of the GIIP for the Artinskian reservoir at Ulyanovskoye, Tsyganovskoye and Tokarevskoye. Xodus used Crystal Ball to run a Monte Carlo simulation to assess the range of GIIP. The simulation was run 10,000 times, with inputs and resulting volumes being separated into the various field segments. These were summed probabilistically to obtain total GIIPs for each field and for the three fields combined.

The GRV calculation was estimated using the different possible contacts as Low, Mid and High cases, as shown in Table 6-1. However, in three structures of the Tokarevskoye field, different areal extension and possible interpretation were also considered to capture a wider range. In Figure 6-3, the Tok-6, Tok-71 pool has a low case GRV which includes only the closure which has been penetrated by the wells, in the high case the pool extends across a small saddle to include the whole structural closure. In the Tok-3, Tok-28_2 pool, the low case includes only the structural closure, the mid case considers the most likely fault closure and the high case includes a more optimistic extent based on a fault further to the east providing the seal. In Figure 6-4, GRV of the Tok-19, Tok-80 area was calculated using two different top structure interpretations.

FIELD/SECTOR	CASE	GWC /M TVDSS	GRV ($10^3 M^3$)		
			LOW POLYGON	MID POLYGON	HIGH POLYGON
Uln-65	Low	-2830		14,956	
	Mid	-2832.5		16,195	
	High	-2835		17,487	
Uln-18	Low	-2830		25,493	
	Mid	-2832.5		27,270	
	High	-2835		29,149	
Uln-63	Low	-2830		11,329	
	Mid	-2832.5		12,689	
	High	-2835		14,149	
Tsyganovskoye	Low	-2794		1,082	
	Mid	-2803		2,387	
	High	-2815		5,249	
Tok-6, Tok-71	Low	-2776	27,945		37,744
	Mid	-2783	37,010		52,395
	High	-2790	48,012		70,332
Tok-2_1	Low	-2787			15,853
	Mid	-2796			19,630
	High	-2802			25,425
Tok-3, Tok-28_2	Low	-2772	189,401	253,073	469,358
	Mid	-2776	198,825	273,145	509,323
	High	-2768	222,386	325,998	615,499
Tok-19, Tok-80	Low	-2796	43,893		135,622
	Mid	-2802	53,196		147,197
	High	-2809	65,262		161,716

Table 6-1 Table with GRV for different contacts and polygon areas

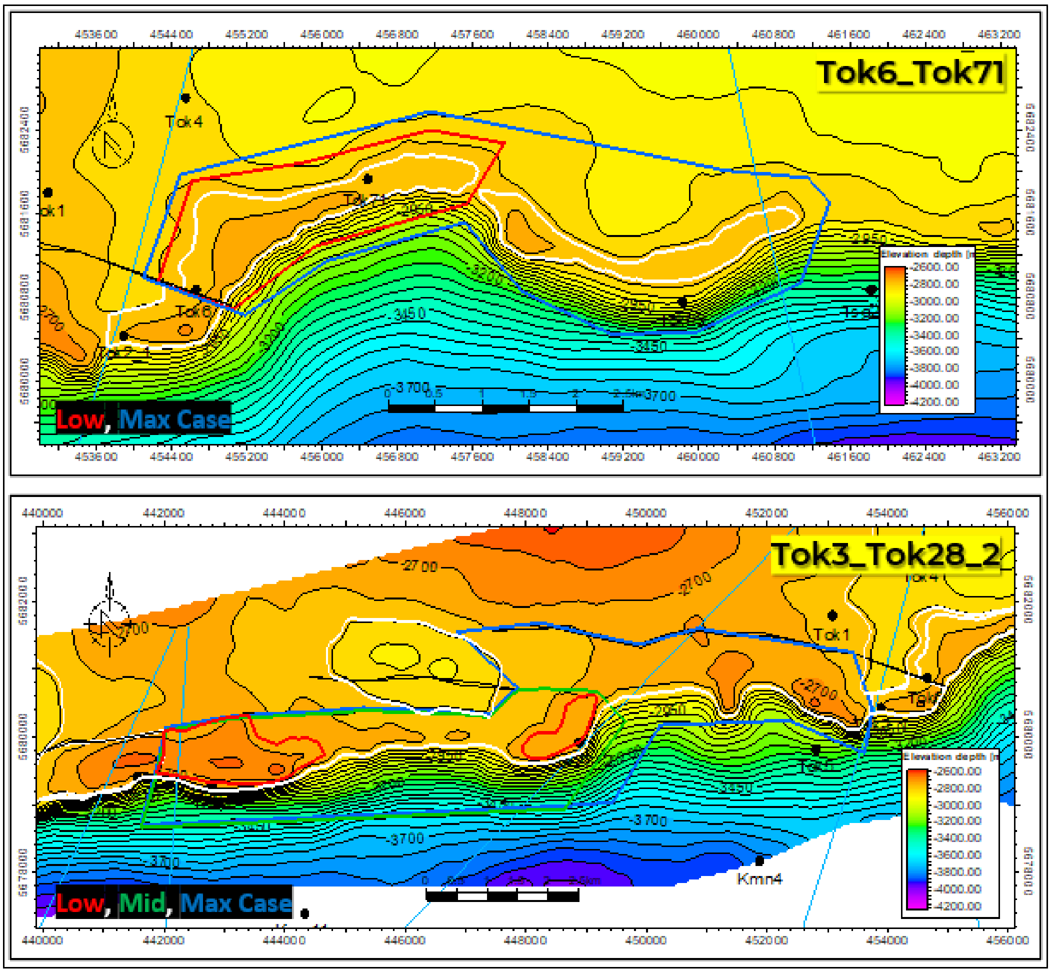


Figure 6-3 Top Artinskian Map with different areal cases (Low, Mid, High) for GRV calculation in two structures of the Tokarevskoye Field

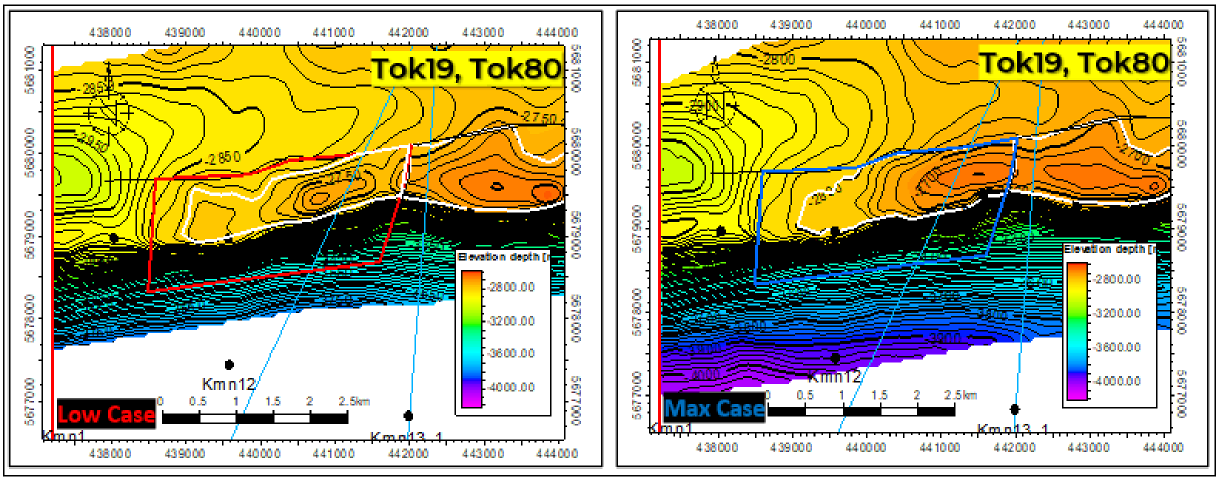


Figure 6-4 Top Artinskian Map with two different interpretations for the same area in one structure of the Tokarevskoye Field.

The range of contacts used for the GRV calculations is shown in Table 6-2, where GDT is the Gas Down To and WUT is the Water Up To.

FIELD/SECTOR	CASE	GWC /m TVDSS	COMMENTS
Ulyanovskoye	Low	-2830	GDT in Uln-65 (well test)
	Mid	-2832.5	Mid-point
	High	-2835	WUT in Uln-63 (well test)
Tsyganovskoye	Low	-2794	GDT in Tsg-24
	Mid	-2803	Possible GWC in Tsg-24 from wireline data
	High	-2815	WUT in Tsg-24
Tok-6, Tok-71	Low	-2776	GDT in Tok-6 (well test)
	Mid	-2783	Mid-point
	High	-2790	WUT in Tok-6 (well test)
Tok-2_1	Low	-2787	Low case GWC interpretation from wireline
	Mid	-2796	GDT in Tok-2_1 (well test)
	High	-2802	High case GWC interpretation from wireline
Tok-3, Tok-28_2	Low	-2772	GDT in Tok-3 (well test)
	Mid	-2776	WUT in Tok-3 (well test) – equivocal result
	High	-2768	Lowest closing contour (LCC)
Tok-19, Tok-80	Low	-2796	GDT in Tok-19 (well test)
	Mid	-2802	Mid-point
	High	-2809	WUT in Tok-19 (well test)

Table 6-2 Ranges of GWC for Western Fields

For the NTG and porosity ranges, the average NTG and Phie was calculated for each well from the available well logs.

For Ulyanovskoye, the well averages were very consistent between the three wells, so a tight low-mid-high range was defined from the range observed in the well data and the same ranges were used for all three pools.

For Tsyganovskoye there is only one well, Tsg-24, which has low reservoir quality. The mid case values were taken as the average NTG and Phie from that well, the high case assumes the well is not representative and takes the average properties from all Artinskian wells in Stepnoy Leopard as an assumed “background”. Given the low values from the well, there is not much scope for further downside, so a sensible low case which fitted a log-normal distribution was selected.

For Tokarevskoye segments “Tok-6, Tok-71” and “Tok-3, Tok-28_2” the average NTG and average porosity for the best and worst well in each segment was taken as the high and low cases, and the mean as the mid case. For segment “Tok-2_1”, the well is relatively high quality, so the well averages were taken as the high case and the average for all Artinskian wells as the low case, with a normal distribution fitted between the two values. For the final segment, “Tok-19, Tok-80” the

NTG of the two wells are at the opposite extremes of what has been encountered across Stepnoy Leopard in the Artinskian, so the low-mid-high NTG ranges were taken from the average ranges across all of the Artinskian in the license to ensure a sensible range of GIIP. The porosity range was taken using Tok-80 as the low case, Tok-19 as the high case and fitting a normal distribution between the two.

Since no reliable Sw measurements were available for the three Western fields, no saturation height function could be derived. Therefore the saturation height functions used for the Artinskian in the four Eastern fields were applied to each of the pools in the west. The height above contact term was taken as the average height of the reservoir above the contact in each of the pools and a range obtained by varying the contact, as defined in Table 6-2. The values used in the Monte Carlo simulation are given in Table 6-3.

		NTG	POROSITY	SW
Ulyanovskoye	Low	0.900	0.076	0.248
	Mid	0.955	0.086	0.185
	High	1.000	0.096	0.122
Tsyganovskoye	Low	0.100	0.041	0.692
	Mid	0.230	0.051	0.432
	High	0.810	0.061	0.173
Tok-6, Tok-71	Low	0.510	0.045	0.497
	Mid	0.660	0.060	0.322
	High	0.810	0.075	0.148
Tok-2_1	Low	0.800	0.075	0.251
	Mid	0.900	0.085	0.187
	High	1.000	0.095	0.123
Tok-3, Tok-28_2	Low	0.360	0.062	0.289
	Mid	0.470	0.072	0.214
	High	0.570	0.081	0.139
Tok-19, Tok-80	Low	0.738	0.057	0.307
	Mid	0.810	0.073	0.218
	High	0.940	0.089	0.130

Table 6-3 Range of Petrophysical Inputs for GIIP Calculation

The resulting range of GIIP is shown in Table 6-4 (note volumes are summed probabilistically, rather than arithmetically), and visually in Figure 6-5, Figure 6-6 and Figure 6-7.

GIIP /BCF	P90	P50	P10
Uln-65	8.6	10.8	13.5
Uln-18	14.7	18.3	22.8
Uln-63	6.7	8.5	10.8
Total Uln	32.6	37.9	44.2
Tsg	0.0	0.2	0.6
Tok-6, Tok-71	5.4	11.5	23.6
Tok-2_1	8.9	12.5	17.5
Tok-3, Tok-28_2	45.2	89.9	176.5
Tok-19, Tok-80	16.9	25.8	37.9
Total Tok	85.6	141.6	244.7
Total Western Fields	123.4	180.2	283.6

Table 6-4 Range of GIIP for Western Fields

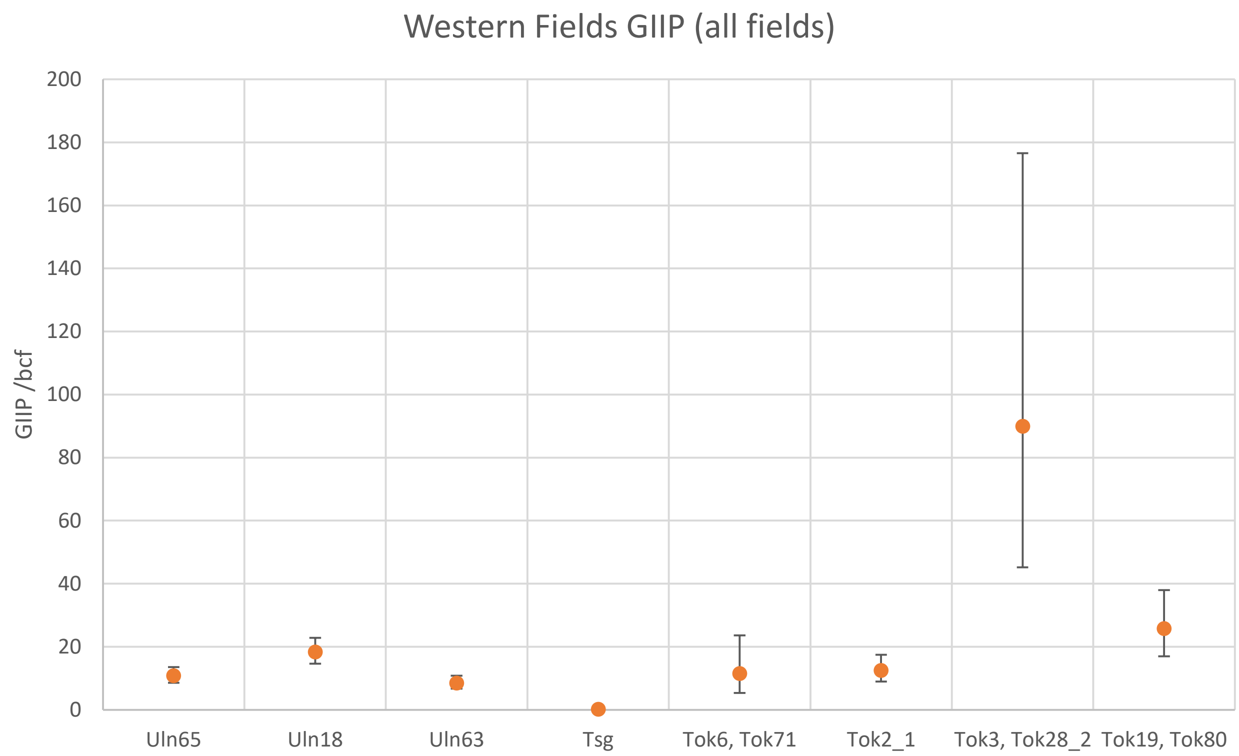


Figure 6-5 Western Fields GIIP (all fields)

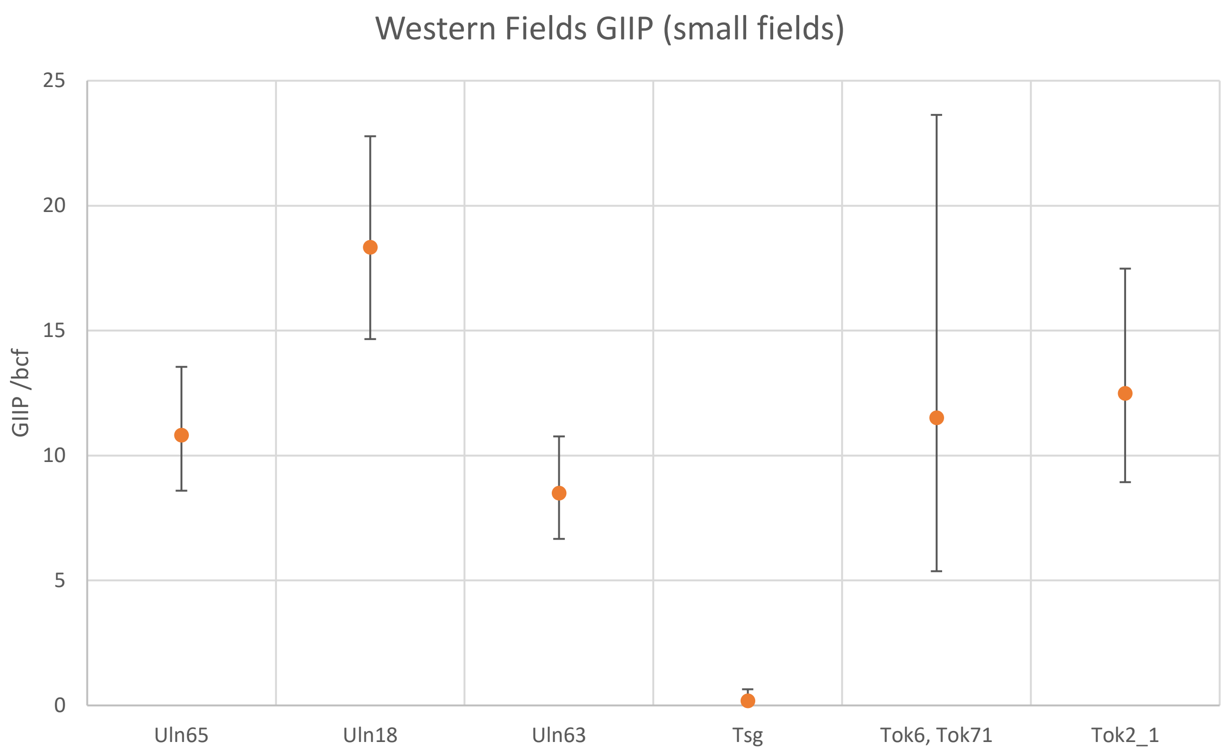


Figure 6-6 Western Fields GIIP (small fields only)

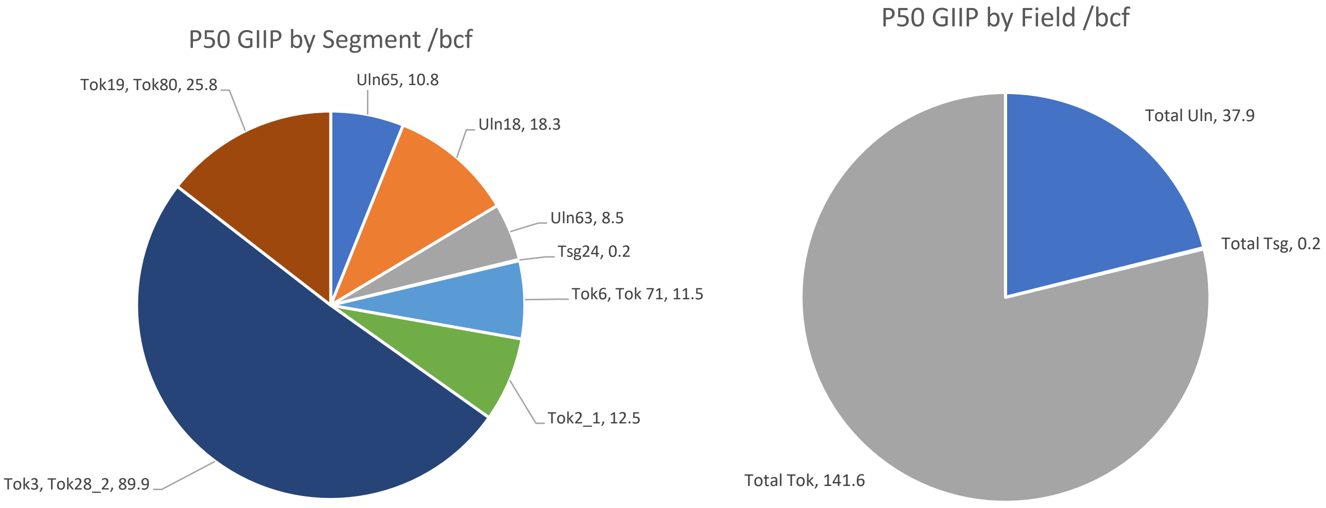


Figure 6-7 Western Fields GIIP by Segment and by Field

The volumes for the three western fields are dominated by the Tok-3, Tok-28_2 pool, with a moderate contribution from the Tok-19, Tok80 pool. All the other fields are relatively small by comparison.

6.5 Recoverable Volumes

As shown above in Figure 6-6 and Figure 6-7 above the currently estimated GIIP and CIIP in the Western Artinskian Fields is materially smaller than the Eastern and Kamenskoye Fields. Given the current gas price, and technical understanding, development of the western Artinskian fields is a lower priority.

Hence currently there is no development plan defined for the three western Artinskian fields; however these are discovered volumes. Therefore Xodus considers these to be Contingent Resources – Development Unclarified. As shown in Table 6-5, Xodus has calculated technically recoverable resources based on its independent assessment of in-place volumes, combined with recovery factors from the dynamic model for the four eastern Artinskian fields. Condensate recovery factors have been assumed to be half of those for the gas.

WESTERN FIELDS TECHNICAL RESOURCES	GAS /BCF			CONDENSATE /MMBBL		
	P90	P50	P10	P90	P50	P10
Recovery factor (%)	64	71	77	32	35	38
Resources (BCF)	79	127	217	1.97	3.19	5.42

Table 6-5 Technically recoverable resources for the western Artinskian fields

7 CARBONIFEROUS AND DEVONIAN PROSPECTIVITY

Most of the Stepnoy Leopard fields are in the Lower Permian Artinskian barrier reef. However, there are nearby fields, such as Rozhkovsky, which have hydrocarbons in the Bashkirian and Tournaisian carbonates of the Lower-Middle Carboniferous. Nostrum's producing field at Chinarevskoye also has oil and gas production from the Tournaisian. These formations are separated by lower-middle Visean and lower Moscovian (Verey Horizon) clastic sections (Figure 7-1).

Below the Tournaisian are upper Devonian barrier reefs that extend for many hundreds of kilometres at depths of 4–5 km and greater. While Chinarevskoye has gas in middle to upper Devonian reservoirs forming a carbonate shelf and slope.

There are local Carboniferous and Permian carbonate buildups (atolls, pinnacles) on top of upper Devonian and lower Carboniferous platform and slope carbonates. These form the Karachaganak field for example, which contains oil and retrograde gas condensate in a hydrocarbon column of over 1600m from the Devonian Frasnian to the Permian Artinskian.

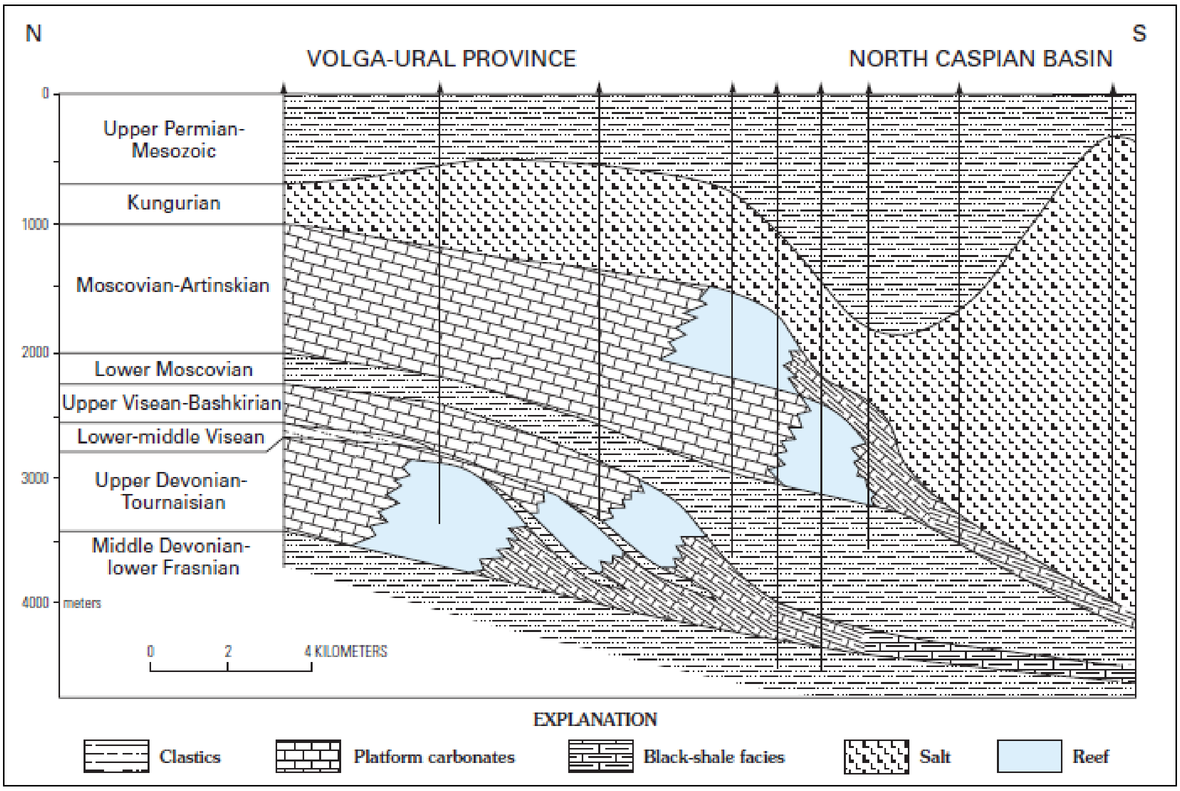


Figure 7-1 Cross section through north basin margin (modified from Grachevsky, 1974). The section is located in the westernmost portion of the northern margin.

Nostrum has identified potential for prospective plays in the Carboniferous and Devonian barrier reef trend in Stepnoy Leopard (Figure 7-2). Xodus has identified and reviewed two prospects in this play. They are four-way dip closures of 13 km^2 and 22 km^2). One is in the area of the 3D seismic Melovaya survey and offset well CK-1, which shows reefal features in the seismic data (Figure 7-3 and Figure 7-4). The other is based on 2D seismic data in the east of Stepnoy Leopard (Figure 7-5 and Figure 7-6).

These may be part of an older Devonian (or early Carboniferous) barrier reef cycle with location as shown in Figure 7-2. This trend has high potential to extend to the west and to form further closures along it. In general, the 2D data is of poor quality. However, there are some lines showing what looks like barrier reefs in the deepest section (Figure 7-6). More information on well CK-1 will be important to incorporate in further studies of this play and leads. Only nine wells have been drilled below the Permian, including the CK-1 well in the license. New seismic acquisition to the north of the KTTT 3D seismic survey in the west of Stepnoy Leopard could reveal more exploration opportunities in this play.

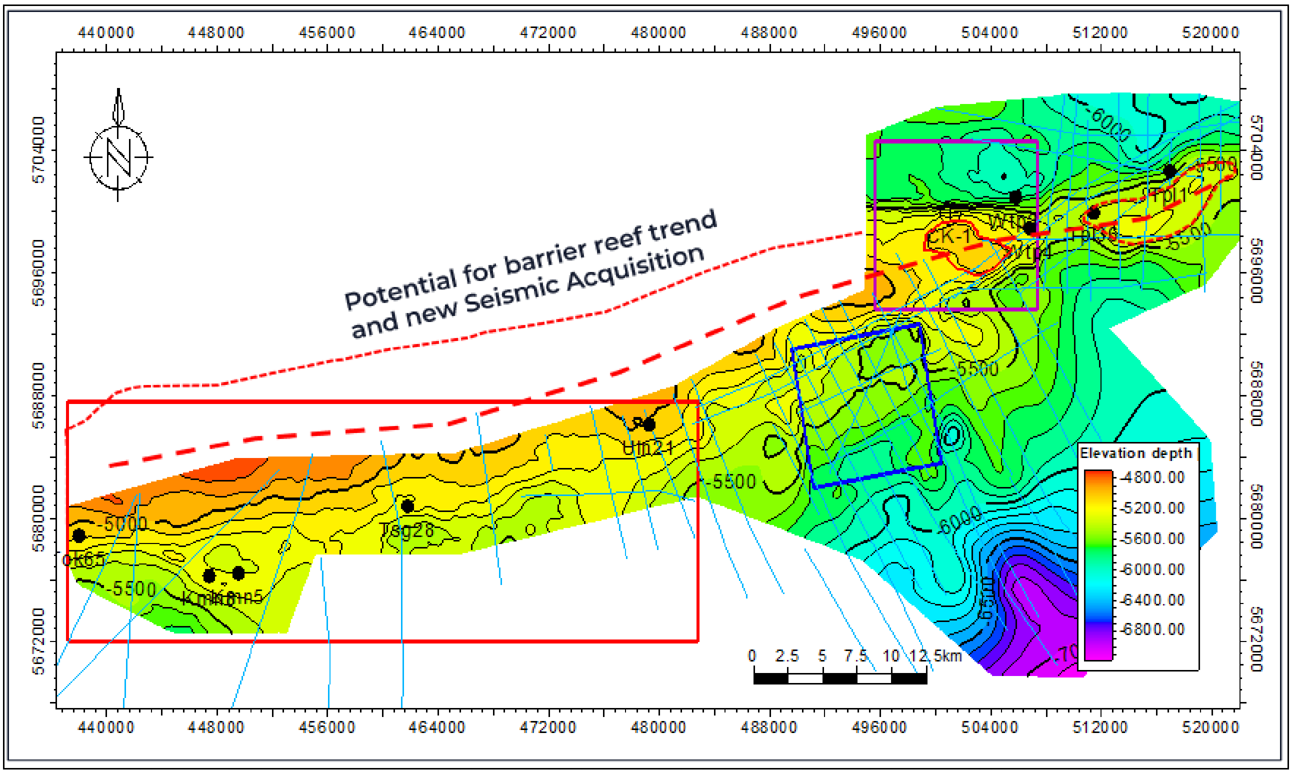


Figure 7-2 Near Devonian Top showing potential barrier reef play and 2 prospects (red) and wells drilled in Carboniferous or Devonian age

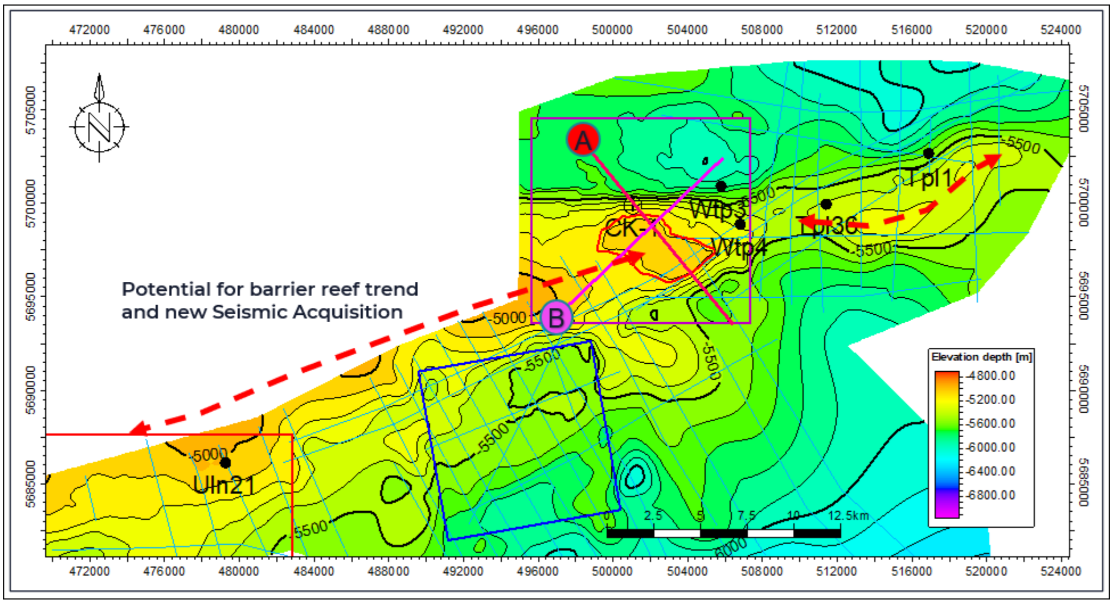


Figure 7-3 Zoom of the Prospect in the 3D Melovaya Survey

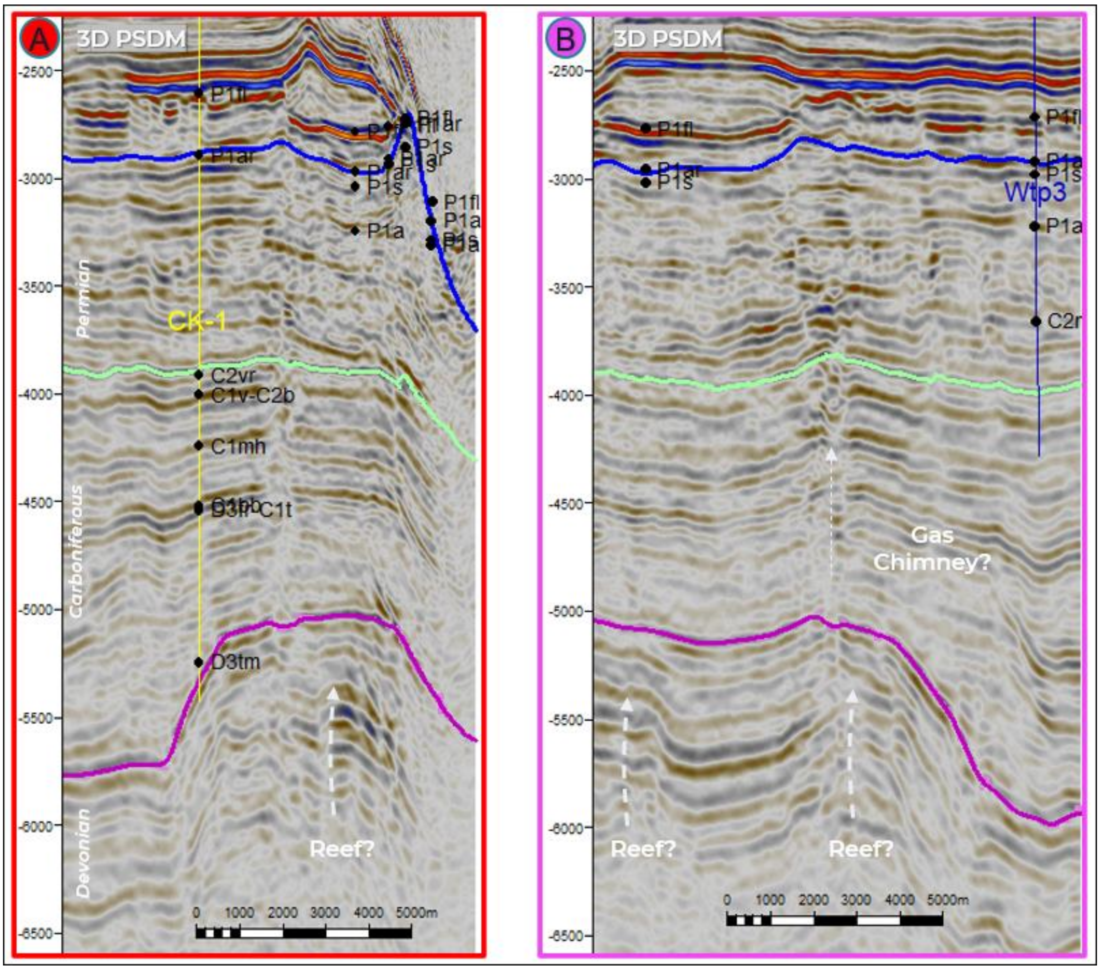


Figure 7-4 Seismic Sections along the prospect in the 3D Melovaya Survey (Purple horizon)

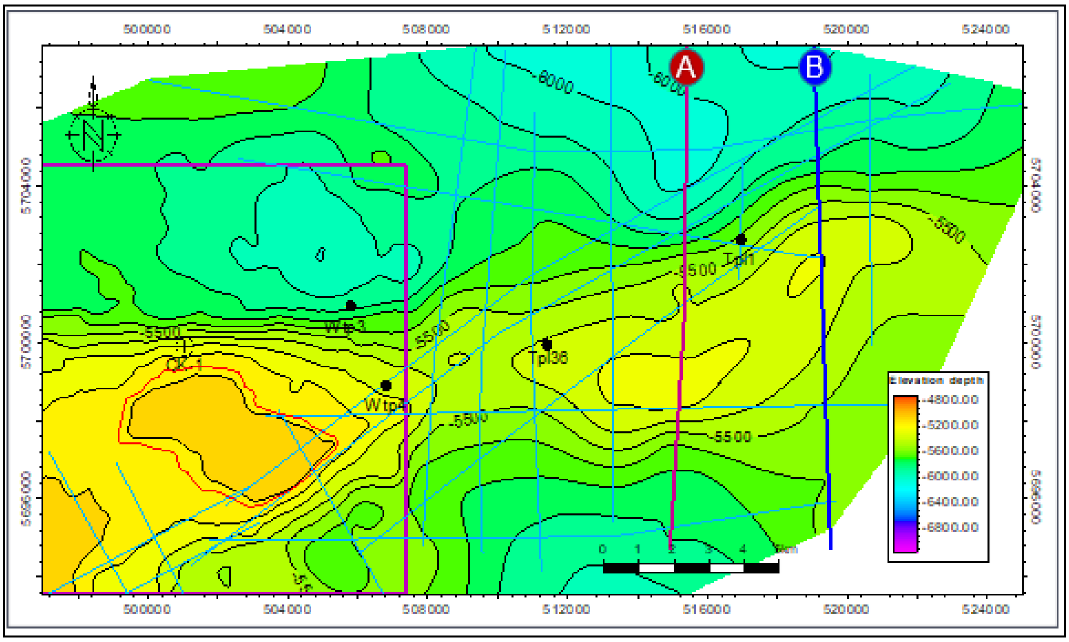


Figure 7-5 Zoom of the prospect identified in the 2D data on the East

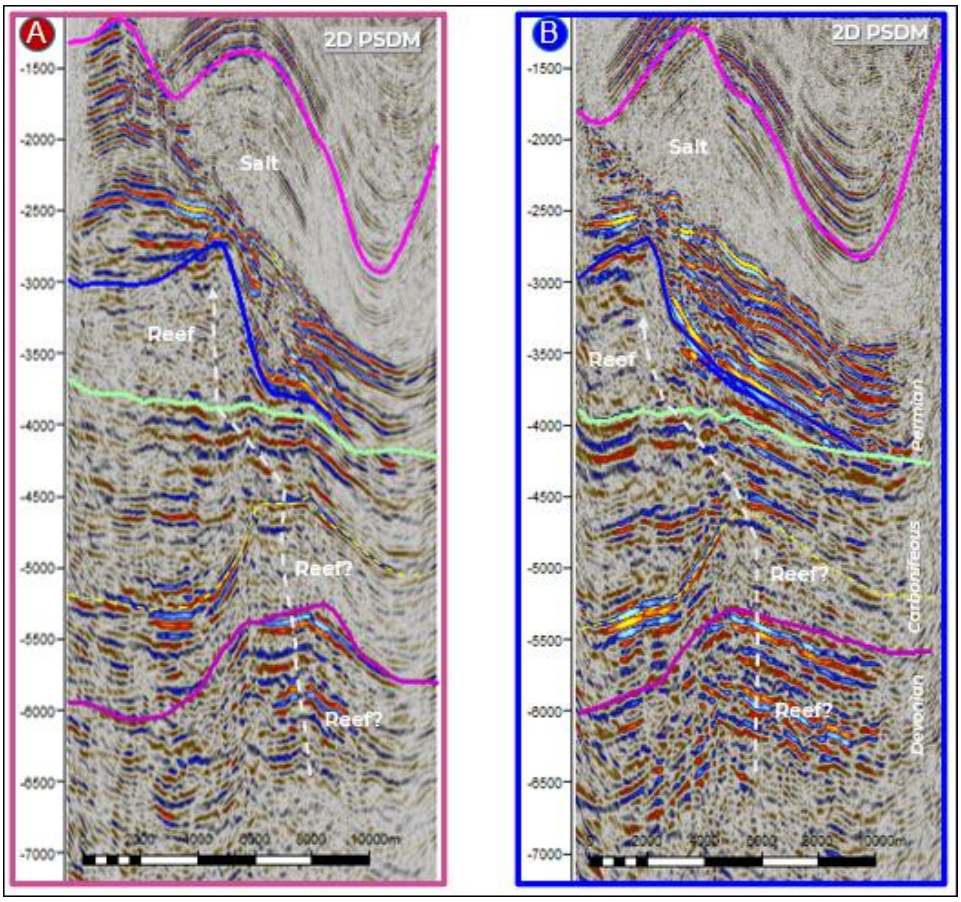


Figure 7-6 2D Seismic Sections along the prospect identified on the East (Purple horizon) and further potential in yellow

APPENDIX A DEFINITIONS

A.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in June 2018, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

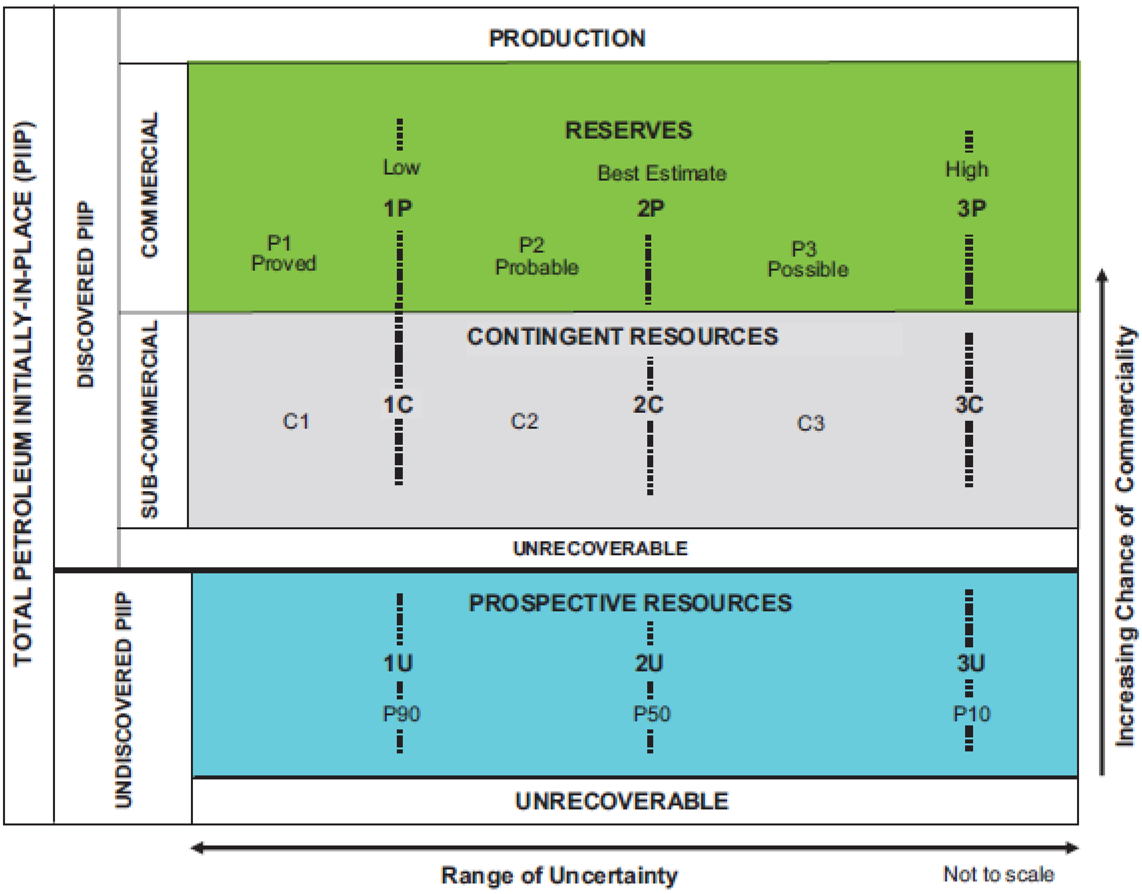


Figure A 1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

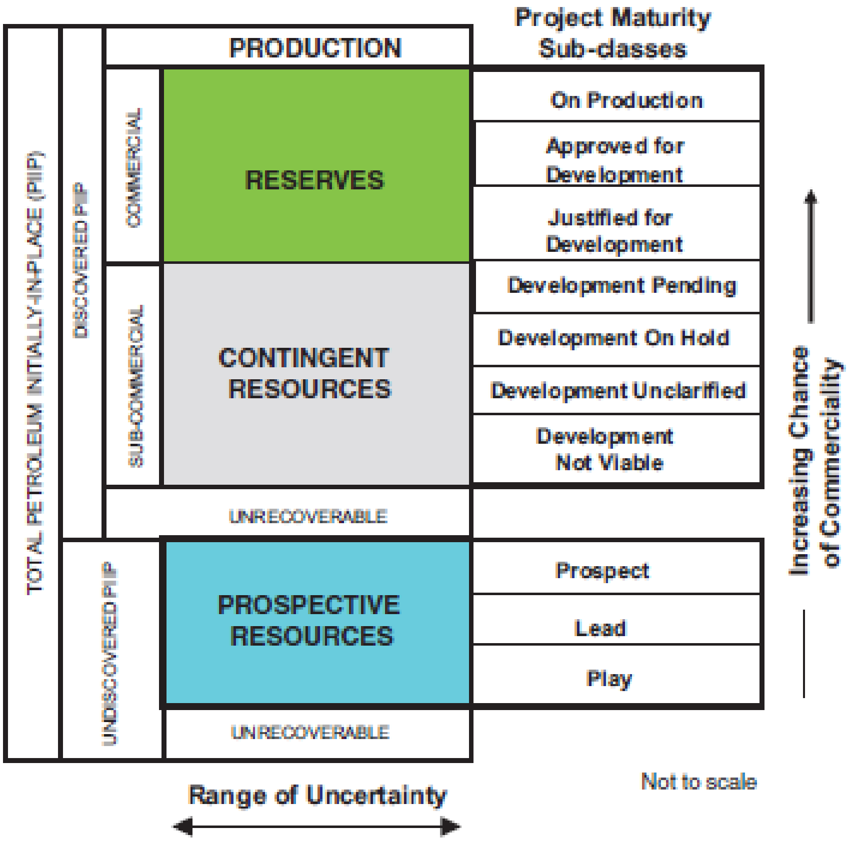


Figure A 2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System 2018)

Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

Undiscovered Petroleum Initially-In-Place

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

A.2 Production

Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

A.3 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: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

(1) From new wells on undrilled acreage in known accumulations,

(2) From deepening existing wells to a different (but known) reservoir,

(3) From infill wells that will increase recovery

(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. 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.

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.

Possible Reserves

Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest 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) Reserves, 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 that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

A.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies.

Contingent Resources have an associated chance of development. 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 categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

1C denotes low estimate scenario of Contingent Resources 2C denotes best estimate scenario of Contingent Resources 3C denotes high estimate scenario of Contingent Resources

Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.

The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Contingent Resources: Development Unclarified

A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.

This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

Contingent Resources: Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.

The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

A.5 Prospective Resources

Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

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

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources 2U denotes best estimate scenario of Prospective Resources 3U denotes high estimate scenario of Prospective Resources

A.5.1 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 geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

A.5.2 Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation 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 geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

A.5.3 Play

A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation 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 geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

A.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

APPENDIX B NOMENCLATURE

ABBREVIATION	DEFINITION	ABBREVIATION	DEFINITION
1D, 2D, 3D	1-, 2-, 3-dimensions	ESP	Electrical Submersible Pump
1P	proved	et al.	and others
2P	proved + probable	EUR	estimated ultimately recoverable
3P	proved + probable + possible	ftMD	feet measured depth
acre	43,560 square feet	ftss	feet subsea
AOF	absolute open flow	G & A	general & administration
API	American Petroleum Institute	G & G	geological & geophysical
av.	Average	g/cm3	grams per cubic centimetre
AVO	Amplitude vs. Off-Set	Ga	billion (109) years
bbl	barrel	GIIP	gas initially in place
bbl/d	barrels per day	GIS	Geographical Information Systems
BHP	bottom hole pressure	GOC	gas-oil contact
BHT	bottom hole temperature	GOR	gas to oil ratio
boe	barrel of oil equivalent	GR	gamma ray (log)
Bscf	billion standard cubic feet	GWC	gas-water contact
Bscm	billion standard cubic metres	H2S	hydrogen sulphide
Btu	British thermal unit	ha	hectare(s)
BV	bulk volume	HI	hydrogen index
c.	circa	HP	high pressure
CCA	conventional core analysis	Hz	hertz
CD-ROM	compact disc with read only memory	IDC	intangible drilling costs
cgm	computer graphics meta file	IOR	improved oil recovery
CNG	compressed natural gas	IRR	internal rate of return
CO2	carbon dioxide	kg	kilogram
DHC	dry hole cost	km	kilometre
DHI	direct hydrocarbon indicators	km2	square kilometres

ABBREVIATION	DEFINITION	ABBREVIATION	DEFINITION
DPT	deeper pool test	kWh	kiloWatt-hours
DROI	discounted return on investment	LoF	life of field
DST	drill-stem test	LP	low pressure
DWT	deadweight tonnage	LST	lowstand systems tract
E & P	exploration & production	LVL	low-velocity layer
E	East	M & A	mergers & acquisitions
e.g.	for example	m	metre
EAEG	European Association of Exploration	M	thousand
Mbbl/d	thousands of barrels per day	OWC	oil-water contact
Mbbl/d	thousands of barrels per day	P & A	plugged & abandoned
mbdf	metres below derrick floor	pbu	pressure build-up
mbsl	metres below sea level	perm.	permeability
mD	millidarcies	pH	-log H ion concentration
MD	measured depth	Ø	porosity
mdst.	mudstone	plc	public limited company
MFS	maximum flooding surface	por.	Porosity
mg/gTOC	units for hydrogen index	poroperm	porosity-permeability
mGal	milligals	ppm	parts per million
MHz	megahertz	PRMS	Petroleum Resource Management System(SPE)
MJ	megajoule	psi	pounds per square inch
ml	millilitres	RFT	repeat formation test
mls	miles	RT	rotary table
MM	million	S	South
MMbbl	million barrels of oil	SCAL	special core analysis
MMboe	million barrels of oil equivalent	scf	standard cubic feet
MMscfd	million standard cubic feet per	scm	standard cubic metre*

ABBREVIATION	DEFINITION	ABBREVIATION	DEFINITION
	day		
MMscm	million standard cubic metres	SPE	Society of Petroleum Engineers
mmsl	metres below mean sea level	SS	sub-sea
MMSTB	million stock tank barrels	ST	sidetrack (well)
MMt	million tons	stbbl	stock tank barrel
mN/m	interfacial tension measured unit	std. dev.	standard deviation
MPa	megapascals	Sw	water saturation
Mscfd	thousand standard cubic feet per day	STOIIP	stock tank oil initially in place
Mscm	thousand standard cubic metres	Tscf	trillion standard cubic feet
Msec	millisecond(s)	TD	total depth
MSL	mean sea level	TDC	tangible drilling costs
mSS	metres subsea	TVD	true vertical depth
MWh	MegaWatt-hours	TVDSS	true vertical depth subsea
N	north	TWT	two-way time
NaCl	sodium chloride	US$	US dollar
NFW	new field wildcat	US$MM	Millions of US dollars
NGL	natural gas liquids	VDR	virtual dataroom
no.	number (not #)		
NPV	net present value		

* 1 scm = 35.3147 scf