SHAMARAN PETROLEUM CORP.

Evaluation of Petroleum Reserves and Contingent Resources
Atrush Field – Kurdistan Region, Republic of Iraq
Based on Forecast Prices and Costs
As of December 31, 2021
Detailed Property Report

McDANIEL

SHAMARAN PETROLEUM CORP.

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Detailed Property Report

Prepared For:

ShaMaran Petroleum Corp.
25th Floor, 666 Burrard Street
Vancouver, British Columbia
Canada V6C 2X8

Prepared By:

McDaniel & Associates Consultants Ltd.
2200, 255 – 5th Avenue SW
Calgary, Alberta
T2P 3G6

March 2022

SHAMARAN PETROLEUM CORP.
ATRUSH BLOCK – KURDISTAN REGION, IRAQ

TABLE OF CONTENTS

McDANIEL

March 31, 2022

ShaMaran Petroleum Corp.
25th Floor, 666 Burrard Street
Vancouver, British Columbia
Canada V6C 2X8

Attention: Mr. Adel Chaouch, President, CEO and Director

Reference: **ShaMaran Petroleum Corp.**
Evaluation of Petroleum Reserves and Contingent Resources
Atrush Field – Kurdistan Region, Republic of Iraq
Forecast Prices and Costs
Detailed Property Report

Dear Sir:

Pursuant to your request we have prepared an evaluation of the petroleum reserves and an assessment of the crude oil and natural gas contingent resources (together the “Evaluation”) as of December 31, 2021 for ShaMaran Petroleum Corp., hereinafter referred to as “ShaMaran” or the “Company”. ShaMaran through its wholly-owned subsidiary General Exploration Partners Inc. has an interest in the Atrush Block within the Kurdistan Region of Northern Iraq.

The reserves and contingent resources estimates have been prepared in accordance with standards set out in the Canadian National Instrument 51-101 (“NI 51-101”) and the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”).

The Company's share of remaining reserves and net present values are presented on a total Company basis in Table 2 at the end of the report. Tables summarizing the reserves, production and revenues for each of the various reserve classes are presented in Tables 3, 4, 5 and 6. A summary of the price forecasts is presented in Table 18.

The Company's share of contingent resources and net present values are presented on a total Company basis in Table 13 at the end of the report. Tables summarizing the contingent resources, production and revenues for the various levels of certainty are presented in Tables 14 through 16. A summary of the price forecasts is presented in Table 18.

An overview of the Atrush Block with a discussion of the geological interpretation, and the methodology for estimating the reserves, revenue forecasts and contingent resources are presented in the Property Discussion of this report. Detailed calculations of the reserves estimates, the contingent resources estimates, the economic parameters employed in the evaluation and the geological maps are presented in the Tables and Figures at the end of this report.

In preparing this report, we relied upon certain factual information including ownership, technical well data, production data, prices, revenues, operating costs, capital costs, contracts, and other relevant data supplied by the Company. The extent and character of all factual information supplied were relied upon by us in preparing this report and has been accepted as represented without independent verification. We have relied upon representations made by the Company as to the completeness and accuracy of the data provided, and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in this report, between the date that the data was obtained for this evaluation and the effective date of this report.

This report was prepared by McDaniel & Associates Consultants Ltd. for the use of ShaMaran Petroleum Corp. and is not to be reproduced or relied upon by any person, company or organization other than ShaMaran Petroleum Corp. without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report was not made available, if any data between the effective date of the evaluation and the date of this report were to vary significantly from that forecast, or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

Cameron T. Boulton, P.Eng.
Executive Vice President
March 31, 2022

Joanne Wong E.I.T.
Evaluation Engineer

Anatoli Tchernavskikh, P.Geol.
Manager, International Geology
March 31, 2022

CTB/JW/AT:jep
[21-0127]

CERTIFICATE OF QUALIFICATION

I, Cameron Boulton, Petroleum Engineer of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an Executive Vice President of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of ShaMaran Petroleum Corp., the report entitled "ShaMaran Petroleum Corp., Evaluation of Petroleum Reserves and Contingent Resources, Atrush Field – Kurdistan Region, Republic of Iraq, Based on Forecast Prices and Costs, As of December 31, 2021, Detailed Property Report", dated March 31, 2022, and that I was involved in the preparation of this report. I am also registered as a Responsible Member as outlined by APEGA for McDaniel & Associates Consultant Ltd. APEGA Permit Number 3145.

2. That I attended the Queen's University in the years 2002 to 2006 and that I graduated with a Bachelor of Science degree in Chemical Engineering, that I am a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of 15 years of experience in oil and gas reservoir studies and evaluations.

3. That I have no direct or indirect interest in the properties or securities of ShaMaran Petroleum Corp., nor do I expect to receive any direct or indirect interest in the properties or securities of ShaMaran Petroleum Corp., or any affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

PROFESSIONAL ENGINEER
CAM BOULTON
ALBERTA

APEGA ID 89981
Calgary, Alberta
Dated: March 31, 2022

CERTIFICATE OF QUALIFICATION

I, Joanne Wong, Engineer In Training of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an Engineer In Training of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of ShaMaran Petroleum Corp., the report entitled "ShaMaran Petroleum Corp., Evaluation of Petroleum Reserves and Contingent Resources, Atrush Field – Kurdistan Region, Republic of Iraq, Based on Forecast Prices and Costs, As of December 31, 2021, Detailed Property Report", dated March 31, 2022, and that I was involved in the preparation of this report.

2. That I attended the University of Calgary in the years 2014 to 2019 and that I graduated with a Bachelor of Science in Chemical Engineering, and that I am a registered Engineer In Training with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of two years of experience in oil and gas reservoir studies and evaluations.

3. That I have no direct or indirect interest in the properties or securities of ShaMaran Petroleum Corp., nor do I expect to receive any direct or indirect interest in the properties or securities of ShaMaran Petroleum Corp., or any affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

Joanne Wong, E.I.T.

APEGA ID 233092
Calgary, Alberta
Dated: March 31, 2022

CERTIFICATE OF QUALIFICATION

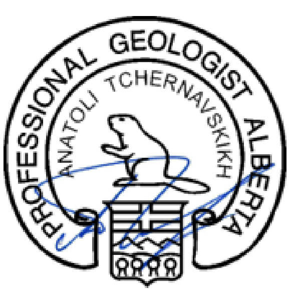
I, Anatoli V. Tchernavskikh, Petroleum Geologist, of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am the Manager of International Geology of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of ShaMaran Petroleum Corp., the report entitled "ShaMaran Petroleum Corp., Evaluation of Petroleum Reserves and Contingent Resources, Atrush Field – Kurdistan Region, Republic of Iraq, Based on Forecast Prices and Costs, As of December 31, 2021, Detailed Property Report", dated March 31, 2022, and that I was involved in the preparation of this report. I am also registered as a Responsible Member as outlined by APEGA for McDaniel & Associates Consultant Ltd. APEGA Permit Number 3145.

2. That I attended Moscow State University (Russia) in the years 1984 to 1991, graduating with a Honorary Master of Science degree in Geology; that I am a registered Professional Geologist with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of 25 years of experience in oil and gas reservoir studies and evaluations.

3. That I have no direct or indirect interest in the properties or securities of ShaMaran Petroleum Corp., nor do I expect to receive any direct or indirect interest in the properties or securities of ShaMaran Petroleum Corp., or any affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.



APEGA ID 66495
Calgary, Alberta
Dated: March 31, 2022

March 31, 2022

ShaMaran Petroleum Corp.
25th Floor, 666 Burrard Street
Vancouver, British Columbia
Canada V6C 2X8

Attention: The Board of Directors of ShaMaran Petroleum Corp.

Re: Revised **Form 51-101F2**
Report on Reserves and Contingent Resources Data
by Independent Qualified Reserves Evaluator
of ShaMaran Petroleum Corp. (the "Company")

To the Board of Directors of ShaMaran Petroleum Corp. (the "Company"):

1. We have evaluated the Company's reserves and contingent resources data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021 estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources as at December 31, 2021.
2. The reserves and contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves and contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2021, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue $M US (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	Dec 31, 2021	Iraq	-	293,183		293,183

6. The following table sets forth the risked volume of contingent resources included in the Company's statement prepared in accordance with Revised Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's Board of Directors:

Classification	**Independent Qualified Reserves Evaluator**	**Effective Date of Evaluation Report**	**Location of Resources Other than Reserves**	**Risked Volume**
Contingent Resources - Development On Hold	McDaniel	Dec 31, 2021	Iraq	1,130 Mbbl Light and Medium Oil; 4,451 Mbbl Heavy Oil
Contingent Resources – Development Not Viable	McDaniel	Dec 31, 2021	Iraq	2,681 Mbbl Heavy Oil;

7. In our opinion, the reserves and contingent resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our report referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our report.

9. Because the reserves and contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

Cam Boulton

Cameron T. Boulton, P. Eng.
Executive Vice President

Calgary, Alberta, Canada
March 31, 2022

SHAMARAN PETROLEUM CORP.

Evaluation of Crude Oil and Natural Gas Reserves and Contingent Resources Atrush Block – Kurdistan Region, Republic of Iraq As of December 31, 2021

Property Discussion

INTRODUCTION

Crude oil reserves estimates and the associated net present values for these reserves were evaluated in this report for the 27.6 percent interest of ShaMaran Petroleum Corp., hereinafter referred to as “ShaMaran” or the “Company” in the Atrush Block (“the Block”) in Iraq. In addition, crude oil and natural gas contingent resources were also estimated. The reserves and contingent resources were estimated as of December 31, 2021 and the revenue forecasts were calculated using forecast prices and costs based on our opinion of future reference crude oil prices at January 1, 2022. The reserves and resources estimates and future net revenue forecasts have been prepared and presented in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and National Instrument 51-101 (“NI 51-101”).

An overview of the property and a discussion of the methodology employed in arriving at the reserves, net present values of the reserves and the contingent resources are presented below.

PROPERTY OVERVIEW

The Atrush Block is located approximately 85 kilometres northwest of Erbil, the capital of the Kurdish administered part of Iraq, as shown in Figure 1 of this report. The Block covers an area of 269 square kilometres (“km^2”) and includes, on the surface, the Chiya Khere Mountain running east to west, which coincides with the Atrush subsurface structure. The Block borders the Shaikan Block to the south where Gulf Keystone found oil in 2009. Immediately to the north of Atrush is the Sarsang Block where HKN Energy is operating the Swara Tika and Swara Tiki East Fields, in which ShaMaran also has a working interest. A more detailed map of the Kurdistan Area of Iraq is presented in Figure 2 of this report.

The Block Production Sharing Contract (the “Atrush Block PSC”) was signed on November 10, 2007. Originally, the participants were General Exploration Partners Inc. (“GEP”), a wholly owned subsidiary of Aspect Holdings LLP (“Aspect”), with an 80 percent working interest and the Kurdistan Regional Government of Iraq (“KRG” or “Government”) with a 20 percent carried third-party interest.

In August 2010, ShaMaran farmed into the Block and acquired a 33.5 percent interest in GEP from Aspect, thereby gaining a 26.8 percent indirect working interest in the Block. In October 2010, the Government assigned their third-party interest to Marathon Oil KDV B.V. (“Marathon”). In December 2012, Aspect sold their entire 53.2 percent indirect interest in the Block to the Abu Dhabi National Energy Company PJSC ("TAQA") who then took over operatorship. Following the sale by Aspect to TAQA of their interest, ShaMaran became the sole shareholder of GEP. In March 2013, the KRG informed TAQA that it intended to exercise its option to acquire a 25 percent interest in accordance with the provisions of the Atrush Block PSC. On November 8, 2016, it was announced that this option had been formally exercised, giving the KRG a 25 percent working interest in the Block effective from November 7, 2012. This has resulted in ShaMaran's interest reducing to 20.1 percent, Marathon's interest reducing to 15 percent and TAQA's interest reducing to 39.9 percent (collectively the Non-Government Contracting Entities ("NGCEs")). Following that, ShaMaran and TAQA agreed to acquire from Marathon, with effect from January 1, 2018, their 15 percent interest in Atrush, which increased ShaMaran's interest to 27.6 percent.

Since 2010, 15 wells (including the CK-9 water disposal well) have been drilled on the Block. The Atrush-1 ("AT-1") exploration well was spudded in 2010 and drilled to a total depth ("TD") of 3,400 metres measured depth ("md"). The well was tested sequentially over 11 intervals producing significant quantities of oil (26.5 degrees API) from three zones incorporating the Barsarin, Naokelekan and Upper and Lower Sargelu formations. As a result of these tests, GEP formally notified the Ministry of Natural Resources ("MNR") in May 2011 that the well was a Jurassic oil discovery and submitted an Appraisal Work Program and Budget ("AWP&B") for a total expenditure of US $137 million.

During 2011 and 2012 the three dimensional ("3D") seismic acquisition defined by the AWP&B was completed. Seismic processing was carried out during the period from 2012 to 2014 resulting in a Pre-Stack Depth Migration ("PSDM") cube.

During 2012, the Atrush-2 ("AT-2") well was drilled to a TD of 1,750 metres md some three kilometres east of AT-1. Separate production tests were carried out on the Mus, Alan, Lower Sargelu, Upper Sargelu and Naokelekan formations. All the tested intervals produced oil with the Naokelekan, Upper Sargelu and Lower Sargelu with each producing more than 10,000 bopd using an electric submersible pump ("ESP"). The Mus and Alan formations flowed what appeared to be heavier, more viscous oil at much lower rates but this was without the aid of an ESP; although the surface oil samples measured a gravity of 10 degrees API (oil-water emulsification suspected) the subsurface samples measured 22 degrees API and are thought to be more reliable. In November 2012, the MNR was notified that the Atrush discoveries were commercial in accordance with Article 12.6 of the Atrush Block PSC.

In March 2013, the Atrush-3 ("AT-3") well was spudded approximately 10 kilometres east of the AT-1 discovery well at a slightly lower structural location. After sidetracking for mechanical problems, the well reached a TD of 1,806 metres md in May 2013. Wireline pressure data in the well suggests pressure communication with the two other wells. The well was tested during July and August 2013 over three intervals with the upper two tests confirming the presence of oil in the Naokelekan ("DST-3") and Upper and Lower Sargelu ("DST-2") formations some 30 metres below the deepest oil tested in AT-2. A test on the Mus Formation ("DST-1") confirmed the presence of water (albeit with approximately five percent oil) at 498 metres subsea ("m ss"). DST-2 produced at rates up to 1,500 bopd and DST-3 produced at rates up to 600 bopd, both with an ESP (the rates are approximate as the viscosity of the fluid prevented flow being diverted through the test separator). The gravity of the oil samples taken at surface ranged from 10 to 17 degrees API.

Other activity on the field during 2013 included the running of a successful interference test between wells AT-1 and AT-2, which are three kilometres apart. The pressure response, as a result of flowing well AT-1 at up to 2,700 bopd, was observed after approximately one day in AT-2 (closed-in) and indicates communication through the fracture system and multi-darcy permeability. It was also determined that AT-1 was unsuitable, due to well integrity issues, for longer term production and was plugged and abandoned later that year.

In May 2013, the Atrush Field Development Plan ("FDP") was submitted to the MNR and subsequently officially approved in October 2013. The FDP called for a phased development with Phase 1 comprising three wells tied back to a processing facility capable of handling up to 30,000 bpd. The FDP approval marked the commencement of the 20 year Development Period with an effective date of October 1, 2013 in accordance with Article 12.9 of the Atrush Block PSC.

Between October 2013 and January 2014, the Atrush-4 ("AT-4") well was drilled to a TD of 2,916 metres md, as a deviated well to appraise the crest of the structure. Due to the surface topography, AT-4 was drilled from the Chamanke-A well pad used for drilling AT-1. The well encountered steeply dipping beds within the front limb of the fold from within the Barsarin and Naokelekan formations that suggested a rollover into the main reverse fault and as such altered the previous structural interpretation. Subsequent stratigraphic correlation suggested that final bed dips were in excess of 80 degrees. The well was tested over three intervals with the upper two tests confirming the presence of oil in what has been interpreted as the Chia Gara Transition Beds ("CGTB") ("DST-3") and Barsarin/Naokelekan ("DST-2") formations. A test on a small interval within the Barsarin Formation ("DST-1") was tight with no production. DST-2 produced at rates up to 3,800 bopd and DST-3 produced at rates up to 5,255 bopd both with an ESP. DST-2 produced oil ranging from 22 to 28 degrees API and DST-3 produced oil ranging from 20 to 28 degrees API. In both cases, an initial emulsion produced during the clean-up phase was successfully broken using demulsifier, providing clean surface samples of the higher gravity oil.

In 2014, the MNR together with the Atrush Management Committee decided, after consultation with the nearby villages, to alter the naming conventions applied to the Atrush Block. As a result, future wells together with the production facilities would be named "Chiya Khere" rather than Atrush, in reference to the Chiya Khere Mountain, under which the field is located, and the well pads used for drilling would be named "Chamanke" in reference to a nearby village. However, the names of the Atrush Block, the four initial wells, the Atrush PSC and Atrush Field were not changed. In June 2014, the Chiya-Khere-5 ("CK-5") development well was drilled to a TD of 2,098 metres mD. The well was deviated from the same well pad ("Chamanke-A") as AT-1 and AT-4 with the bottom-hole location in the Butmah Formation approximately 870 metres west southwest of the surface location. The well came in slightly high to prognosis and with slightly better reservoir than expected. This was followed by the drilling of Chiya Khere-8 ("CK-8") development well, again drilled from the Chamanke-A pad, which is the highest structural well drilled to date. The well came in more or less on prognosis.

Chiya-Khere-6 ("CK-6"), the second appraisal well in the eastern "Phase 2" area of the field, was drilled reaching a TD of 2,105 metres md in November 2014. CK-6 was drilled from the Chamanke-C well pad used to drill AT-3 and has a bottom-hole location approximately 1.1 kilometres southeast of AT-3. The well encountered steeply dipping beds within the front limb of the fold (up to a calculated maximum dip of 45 degrees) within the Alan Formation, which, as with AT-4, impacted the local structural interpretation. The well was tested at the end of 2014 using an ESP over three intervals with the upper two tests confirming the presence of oil in the Naokelekan ("DST-3") and Lower Sargelu ("DST-2") formations. A test on the Alan Formation ("DST-1") produced heavy oil with limited flow preventing recovery of the load fluids. DST-3 produced oil of 26 degrees API at rates up to 7,331 bopd and DST-2 produced at rates up to 1,700 bopd. The oil produced during DST-2 was denser than DST-3 (13 versus 26 degrees API) and, although the surface samples were emulsified with water, are unlikely to be equivalent. In addition, pressure gauges confirmed vertical pressure communication between the DST-2 and DST-3 intervals and together with the density data suggests the oil compositionally grades with depth. During the CK-6 well testing, pressure gauges were run in the AT-2 well to measure interference. Pressure interference is clear on AT-2 gauges establishing pressure communication over the 6.6 kilometres distance between the wells.

In January 2015, well AT-3 was re-entered, re-stimulated with acid, and tested as a commingled Lower Sargelu and Naokelekan producer. The interval produced 14 degrees API oil, at rates ranging between 1,650 to 3,000 bopd. Interwell gauges installed in wells AT-2 and CK-6 monitored the pressure response during the testing of AT-3, and communication with AT-3 was observed in both wells.

An extended well test was run on AT-3 in 2019 to evaluate the productivity and characteristics of the heavy (13 degrees API) oil within the Lower Sargelu and Naokelekan. This testing was inconclusive.

Well CK-5 was tested across three intervals in May and June 2015, confirming the presence of oil in the Naokelekan (“DST-3”), the Lower Sargelu (“DST-2”) and the Mus (“DST-1”) formations. DST-1 produced 13.2 degrees API oil from the Mus at rates up to 1,500 bopd, DST-2 produced 24.4 degrees API oil from the Lower Sargelu at rates up to 9,200 bopd and DST-3 produced 24.7 degrees API oil from the Naokelekan at rates up to 2,100 bopd. Vertical interference gauges confirmed the hydraulic isolation between the Mus and the Upper Jurassic formations, which is likely caused by anhydrites within the Alan Formation providing an effective seal and barrier to flow. The gauges also confirmed vertical communication between the Lower Sargelu and the Naokelekan formations in the Upper Jurassic. The well has been completed on the Lower Sargelu and Naokelekan formations, with the Mus Formation suspended.

Well CK-8 was tested across two intervals in July and August 2015, confirming the presence of oil in the Sargelu (“DST-2”) and the Mus (“DST-1”) formations. DST-1 produced 26.6 degrees API oil from the Mus at rates up to 4,420 bopd and DST-2 produced 23.9 degrees API oil from the Sargelu at rates up to 8,263 bopd. Vertical interference gauges confirmed the results seen in well CK-5, showing hydraulic isolation between the Mus and the Upper Jurassic formations and also vertical communication between the Sargelu and the Naokelekan formations. The well has been completed on both the Mus and Sargelu formations.

In November 2015, TAQA submitted an updated FDP to the MNR, which outlines the work required to further delineate the Atrush Field and to commence full production. As part of this, the CK-7 well was drilled in 2017 and came in structurally higher than prognosis. Core was recovered from four intervals including the Naokelekan, Lower Sargelu, Alan Dolomite and Mus. The well was tested in 2018 using an ESP over three intervals, Lower Sargelu (“DST-3”), Alan (“DST-2”) and Mus (“DST-1”). DST-1 produced between 20.1 and 20.5 API oil from the Mus with rates during the main flow period of 831 bopd, DST-2 produced 27.1 API oil from the Alan at rates of 934 bopd and DST-3 produced 26.4 API oil from the Lower Sargelu at rates of 1,036 bopd. This well was completed in 2018 in the Lower Sargelu and Alan.

In 2018, the water disposal well, CK-9, was drilled in additional to the Upper Jurassic medium oil producer, CK-10. Well CK-10 was perforated in the Sargelu and produced 26 API oil with initial rates during the ESP completion flow of 3,497 bopd.

The 2019 development campaign entailed drilling CK-11, CK 12, CK-13 and CK-15. The CK-11 well targeted the Upper and Lower Sargelu which produced at 8,200 bopd. The CK-12 well targeted the Mus Formation; however, it has a lower than expected reservoir productivity index with rates of around 400 bopd and was converted to an Upper Jurassic producer in April 2021 with initial rates of around 5,000 bopd. The CK-13 well targeted the Naokelekan and the Upper Sargelu and produced at initial rates of 5,500 bopd. Well CK-15 targeted the Upper and Lower Sargelu and produced at rates of over 7,000 bopd.

During 2020 and 2021 new 3D seismic re-processing and re-interpretation work was performed by TBI. A total of 360 square kilometres of seismic volume was re-processed and a new velocity model was utilized. The final interpretation was done based on a new PSDM cube. The resulting structural mapping appears to be significantly different and ShaMaran intends to conduct a detailed seismic review of this latest work.

In 2021, CK-17 was drilled in the western part of the field south from CK-5. The well came in approximately 200 metres deeper than prognosis and did not encounter the Barsarin Formation and was ultimately abandoned. This area could be separated by a fault from the main field and is significantly deeper than expected. ShaMaran hired a third-party to conduct a detailed seismic review as the latest seismic interpretation also does not tie to this well. This is discussed later in this report.

The new sidetrack CK-17ST was drilled further inward between AT-1 and CK-8 and was successfully completed in the Upper Jurassic at initial rates of around 2,000 bopd. Plans are to conduct a workover of this well to increase the production rates of this well upwards of 5,000 bopd.

A summary of the well tests within the tested Atrush wells is presented in Table 1 at the end of this report with the formations listed according to the latest stratigraphic nomenclature.

First oil from the Atrush Field was achieved on July 3, 2017, with export being sent on July 16, 2017 via a 35 kilometre trunk line to the Khurmala-Fishkabour export pipeline to Turkey. At the end of December 2021, the total field production was approximately 40,000 bopd at 12 percent water-cut with the majority of production coming from the Upper Jurassic.

TAQA and its partners are committed to drilling wells in the core area as part of a drill to fill philosophy. Crude oil reserves have been assigned as part of this evaluation to the development of the core oil region. The remainder of the discovered, potentially recoverable volumes are classified as contingent resources.

SOURCE AND QUALITY OF DATA

All the basic information available up to and including December 31, 2021 was provided by ShaMaran and employed in the preparation of this report.

GEP acquired 143 kilometres of two dimensional ("2D") seismic data in 2008 comprising five dip lines and three strike lines. During 2011 and 2012, a 309 square kilometre 3D seismic survey was acquired over the Atrush structure in two batches. The seismic data was provided within a Kingdom Project and included ShaMaran's PSDM interpretation and depth grids of the key Jurassic horizons. The seismic quality is affected by the large topographic variations associated with the Atrush anticline, particularly the crestal part of the structure. In 2020 and 2021, the seismic was re-processed and re-interpreted and ShaMaran has conducted its own review of this work and the results of this work have been incorporated into this Evaluation.

Atrush well data including mud logs, wireline logs, core data and well test data were provided for all the wells together with an updated FDP submitted to the Government in 2015.

Production and test data were provided for all wells in digital format. Additionally, the 2020 Technical Committee Meeting ("TCM") and Management Committee Meeting ("ManCom") documents and presentations were also available for review.

In our opinion, the data available for this evaluation was of sufficient quality commensurate with the classification of reserves and contingent resources.

REGIONAL GEOLOGY

The Atrush Block is located within the Zagros Sedimentary Basin (the "Basin"), which is a world-class hydrocarbon province, located on the northeastern margin of the Arabian Platform. This Basin is located along the Zagros thrust belt and covers an area of some 200,000 square kilometres. It extends from the Taurus thrust zone in the north (Turkey) to the Arabian Gulf and Oman in the south. The Basin is a typical foreland compressional basin formed by the collision of the Afro-Arabian and Iranian plates in Late Cretaceous and Cenozoic times.

The Zagros Basin is characterized by a series of sub parallel faults, compressed anticlines and adjoined synclines along the Zagros mountain system. Deposition within the basin is interpreted as the product of three major geotectonic events:

- Opening of the Neo-Tethys Ocean in late Permian–Triassic time.
- Expansion of the Basin in Jurassic and early Cretaceous time when massive carbonate sedimentation occurred in the Basin.
- Burying and closing of the Basin in late Cretaceous Turonian time when the Iranian platform collided with the Arabian plate.

The late Permian and Triassic rocks were deposited in relatively stable shelf conditions and consist of shallow water carbonates with minor evaporite and clastic content. Jurassic sediments were also deposited in the shelf environment and consist primarily of carbonates ranging from deep water mudstones-wackestones to shallow water packstones-grainstones interbedded with supra-tidal carbonates and anhydrites.

From middle Jurassic to late Cretaceous time the carbonate platform was divided into several semi-isolated basins. Clastic sedimentation dominated the western part of the area. Several uplifts and erosional periods occurred in Cretaceous time. Carbonate deposition was dominant during Mesozoic time in the Zagros Basin Area.

During the Alpine orogeny, Neo-Tethys oceanic crust was overthrusted on to Arabian passive continental margin and dramatically changed the structural and stratigraphic regime of the area. A northwest southeast trending foredeep was developed along the rising orogen. While flysch deposits accumulated along the thrust zone, deeper shelf pelagic limestone and marls were deposited towards the west.

During Paleocene–Early Eocene time, a deep open marine basin was oriented along the thrust belt in northern Iraq. Carbonate and evaporite sediments were deposited in the central and southwestern parts of the basin and coarse clastic rocks were deposited in the northeastern areas.

Folding and uplift of the Zagros Mountains began in the Late Cretaceous and the upper Miocene and Pliocene rocks have syn-orogenic and post-orogenic genesis.

According to published information, the main source rocks in the area are in the Jurassic Sargelu and Naokelekan formations. Additional hydrocarbon source rocks are found in the Cretaceous Chia Gara Formation and Triassic Kurra Chine Formation. Hydrocarbon generation and migration in the Zagros Basin began during the late Cretaceous time. Faults and fracture development created vertical migration paths to hydrocarbons, but may have also resulted in some hydrocarbon loss. Most likely a combination of vertical and horizontal migration charged the structures in the Atrush Block Area.

Geology of the Atrush Block

The Atrush Block is located within an intensively folded and thrusted zone close to the Zagros Mountains. The main feature within the block is a compressed anticline visible both at surface and in the seismic data. The Atrush structure has been interpreted as a fault propagation fold, which is supported by very steep dips observed in wells close to the front limb of the structure. The main trap is interpreted as a four-way dip closed structure, but there is a possibility the structure is a three-way dip closed with a fault to the south. Upper Cretaceous and Aqra-Bekhme carbonates are mostly mapped at surface; however, locally Qamchuqa sediments may be exposed. Based on the drilling results, the stratigraphical section appears similar to the nearby Shaikan Block where the Shaikan-1 well established reservoirs in the Cretaceous, Jurassic and Triassic sections. The Aqra-Bekhme and Qamchuqa formations of the Cretaceous, which are common reservoirs elsewhere in the region, are not considered prospective as they are close to surface, intensively fractured and have no anhydrites or shale present to act as seals. The discovered hydrocarbons within the Atrush Field are interpreted to be in the Jurassic section.

ShaMaran's 3D seismic interpretation shows the main axis of the anticline is parallel to an east to west oriented thrust fault interpreted on the south side of the structure that extends to surface. There is significant structural uncertainty due to the quality of the 3D seismic over the crest of the structure and based on surface geology work TAQA interprets the structure as four-way dip closed and this interpretation has been used for the purposes of this evaluation.

The results of all drilled wells, including the data from drilling, wireline logs (including fracture analysis from borehole imagery), core data, pressure data and well test data were used as the basis for this Evaluation. A stratigraphic summary of the geology and based on our interpretation of the data is presented in Table 1 below with columns indicating the main reservoirs, source rocks and seals as related to the Atrush Field.

Table 1 – Atrush Block Stratigraphic Summary

e	Epoch	Formation (1)	Lithology	Reservoir	Source	Seal
Cretaceous	Upper	Aqra-Bekhme	Karstic & Dolomitic Limestone			
		Qamchuqa	Karstic & Dolomitic Limestone			
	Lower	Sarmord	Interbedded Marls, Limestone & Shale			
		Garagu	Limestone			
		Chia Gara	Shale & Marls			
Jurassic	Upper	Chia Gara Transition Beds	Shale with layers of Anhydrite and Limestone			
		Barsarin	Shale & Marls over Limestone with Anhydrite			?
		Naokelekan	Organic rich Shale with layers of Limestone			
	Middle	Upper Sargelu	Limestone & Shaly Limestone			
		Lower Sargelu	Dolomite with layers of Limestone			
	Lower	Alan	Anhydrites with a few layers of Dolomite			
		Mus	Limestone & Dolomite			
		Adaiyah	Predominantly Anhydrite with some Dolomite			
		Butmah	Dolomite with isolated layers of Anhydrite and Limestone			
Triassic	Upper	Baluti	Interbedded Marls, Dolomites & Shale			
		Kurra Chine A	Interbedded Anhydrite, Limestone & Dolomite		?	
		Kurra Chine B	Interbedded Anhydrite, Limestone & Dolomite		?	
		Kurra Chine C	Interbedded Anhydrite, Limestone & Dolomite		?	

(1) A wavy line between formations represents an unconformity.

The Jurassic formations consists mostly of carbonates and anhydrites with the anhydrites mostly located in the Barsarin and Alan formations.

Source rocks are present in the Naokelekan and Chia Gara formations. Deeper source rocks are possible based on regional information but have not been identified by the existing wells. Fluid samples from various wells suggest the oil gravity increases with depth from 26.5 degrees API in the Barsarin in well AT-1 to 13.4 degrees API in the Sargelu in well CK-6; the solution gas-oil ratio ("GOR") varies from 140 to 300 scf/bbl. Based on the geochemical analysis of the crude oil sampled from many wells, the Atrush Field may have multiple oil sources.

Reserves and contingent resources were assigned to six intervals in Jurassic section: Barsarin, Naokelekan, Upper Sargelu, Lower Sargelu, Alan and Mus. Estimations of the net pay, porosity and water saturation were derived from petrophysical analysis of the wells drilled within the field boundary. Porosity was estimated from the neutron and density logs and backed up by the sonic log. Net reservoir was determined using a five percent porosity cut-off, which is based on core analysis and analogous regional reservoirs.

The production rates obtained during testing (and summarized in Table 1 at the end of this report) are a function of the fracturing present at a given well location rather than the quality of the underlying reservoir matrix; however, most transient pressure analysis from the well tests in most wells indicate the presence of a dual porosity system. Petrophysical analysis indicates the best developed matrix porosity is present within the dolomite layers of the Lower Sargelu and Mus formations, which have an overall average porosity of 10.2 and 8.8 percent, respectively. Typically, with carbonate reservoirs, the properties of any particular zone can be highly variable across the field. The Naokelekan Formation is regionally an organic rich carbonate source rock; the organic matter, which has a very low matrix density and sonic matrix transit time, can sometimes be misinterpreted as high porosity carbonates. In Atrush, most matrix porosity within the Naokelekan has been occluded by kerogen. The Alan Formation is comprised of an upper and lower anhydrite, which based on the vertical interference tests in wells CK-5 and CK-8 acts as an intra-reservoir seal. The Alan Formation does contain some layers of dolomite which were productive in wells AT-2 and CK-7 and oil bearing (but with limited productivity) in CK-6.

Top structure and gross oil thickness maps for each of the intervals assigned reserves and/or contingent resources are presented in Figures 3 to 20 at the end of this report. The uncertainty in the oil-water contacts ("OWC") and the various oil density interfaces presented on the maps are discussed in more detail in the next section.

RESERVES AND CONTINGENT RESOURCES EVALUATION METHODOLOGY

The methodology adopted for this Evaluation was to first estimate the discovered, potentially recoverable resources (reserves plus contingent resources) and then the reserves. The contingent resources were then estimated incrementally. In the case of the heavy oil contingent resources, the total recoverable resource was split into an additional drilling component as part of the next potential drilling campaign aligned with the remainder of the medium oil and a heavy oil focused development, tied specifically to incremental heavy oil volumes. This allowed for the heavy oil contingent resources to be broken into two groups: those volumes associated with a development on hold and those volumes associated with a development not currently viable. This is discussed further in the Contingent Resources section of the report.

For this Evaluation, the discovered, potentially recoverable resources were estimated deterministically. A summary of the parameters used and their basis is presented in Table 2 below.

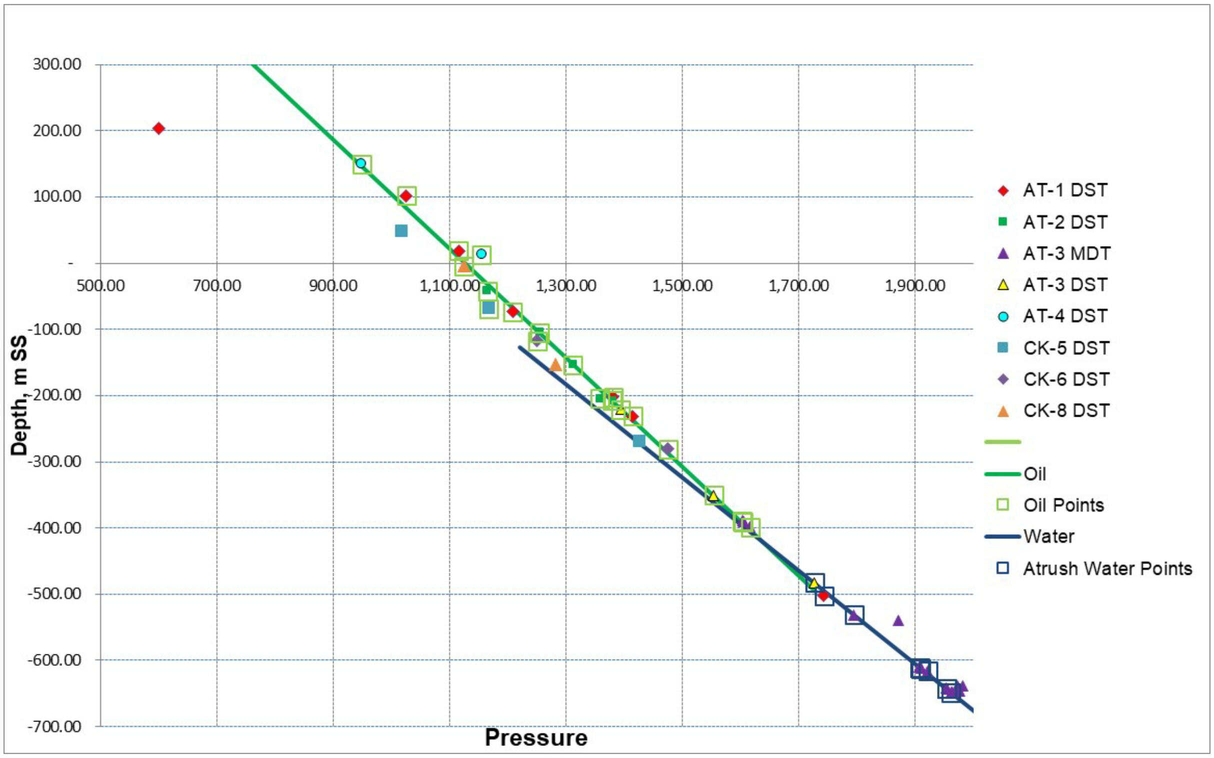
Table 2 – Basis for Evaluation Input Parameters

Input Parameter	Source of Estimate
Gross Rock Volume	Atrush 3D Seismic and well results
Matrix Net to Gross Ratio	Available well data
Fracture Net to Gross Ratio	Kurdistan experience
Matrix Porosity	Available well data and Kurdistan experience
Fracture Porosity	Worldwide carbonate experience and inferences from well test data
Matrix Oil Saturation	Available well data
Fracture Oil Saturation	Worldwide carbonate experience
Oil Shrinkage	PVT data
Solution Gas GOR	PVT and well test data
Matrix Recovery Factor	Well performance, reservoir simulation and worldwide carbonate experience
Fracture Recovery Factor	Well performance, reservoir simulation and worldwide carbonate experience

Based on well test data the Barsarin, Naokelekan, Upper Sargelu and Lower Sargelu, collectively the "Upper Jurassic formations," appear to be in pressure communication within a single oil column. Oil within the Alan and Mus formations is not in direct pressure communication with the Upper Jurassic formations and are assumed to have separate oil column. Oil density and viscosity appear to increase with depth but it is unclear if this is because there is more than one oil source or because of compositional grading.

Whilst it appears highly likely that there may be several oil columns present, pressure analysis, assuming a common aquifer, indicates the variation in OWC could still be relatively small. The pressure data is presented in Figure 1 below with the oil points plotting on an oil gradient of 0.370 psi/ft.

Figure 1 - Atrush Field Pressure-Depth Plot



The well test data in general, and in particular in the CK-6 (DST-2 and DST-3), indicates the oil becomes denser with depth implying the oil gradient would also normally increase with depth. A change of oil gradient cannot be determined from Figure 1 above and is likely masked by the resolution of the pressure data; the gradient is mostly based on well test data, rather than wireline ("MDT") data which was only run in AT-3. This shortcoming also prevents determining a reliable OWC estimate from the pressure-depth plot.

Oil-water contacts have therefore been estimated as the mid-point between the lowest tested oil ("LTO") and either the highest tested water ("HTW") or the lowest closing contour ("LCC") when, as is the case of the Upper Jurassic Formation and the Alan Formation, no water has so far been tested. To account for the increasing oil density with depth, the Lower Jurassic Formation and Upper Jurassic Formation were divided between medium oil and heavy oil. A summary of the resulting fluid levels is presented in Table 3 below. The medium oil region for the Upper Jurassic is represented by the 26 to 27 degrees API oil produced in well tests above -232.6 m ss that pressure-volume-temperature ("PVT") analysis suggests has an in-situ oil viscosity of approximately 5 to 10 cP. Well CK-7 tested 20.1 to 20.5 API from the Mus Formation at base perf of -176 m ss and it is expected that this is near the medium-heavy interface. The heavy oil region of the Upper Jurassic is represented by the successful tests that have produced oil at somewhat lower rates with apparent oil gravities below 20 degrees API (for example CK-6 DST-2) with an in-situ viscosity of 50 to 500 cP. Whilst this is a simplistic approximation of what is likely to be a gradual transition in oil quality, it is considered a reasonable approach for the purposes of this evaluation given the overall uncertainty in the gross rock volume ("GRV").

Table 3 – Atrush Field Estimated Fluid Levels from Well Tests

Formation	Oil Density Region	Fluid Level	Depth, m ss	Based on Well/DST
Upper Jurassic	Medium	LTO	-225.9	AT-2 DST#3
	Medium-Heavy	**P50 Interface**	**-232.6**	
	Heavy	HTO	-239.4	AT-3 DST#3
	Heavy	LTO	-408.1	AT-3 DST#2
	Heavy	LCC	-490.0	
	Heavy	**P50 OWC**	**-449.1**	
Lower Jurassic	Medium	LTO	-176.0	CK-7 DST#1
	Medium-Heavy	**P50 Interface**	**-215.0**	
	Heavy	HTO	-254.4	AT-2 DST#2
	Heavy	LTO	-376.3	AT-2 DST#1
	Heavy	HTW	-498.2	AT-3 DST#1
	Heavy	**P50 OWC**	**-437.3**	

(1) LTO - Lowest Tested Oil
(2) HTO - Highest Tested Oil
(3) HTW - Highest Tested Water
(4) LCC - Lowest Closing Contour

To incorporate the different fluid types, three separate deterministic calculations were made for each formation. GRV estimates were derived from gross oil thickness maps. The GRV ranges incorporate the possible variation in the fluid contacts and the likely extent of the discovered resources. Total resource volumes for all formations, were based on the full mapped area and varying percentages of the West Area which is more uncertain due to the results of the CK-17 well as shown on the maps presented in Figures 3 to 20 at the end of this report. For the medium oil volumes, the total proved + probable + possible ("3P") case included the entire volume in the West and the 1P case did not include any of the volume in the West. The total proved + probable ("2P") was based on the average of the two at 50 percent. It is expected that this will be further modified as more seismic work is undertaken to understand the flanks of the structure.

A range of porosities was used to estimate the in-place volumes but other reservoir properties were held constant to avoid aggregating too many low and high estimates. The fracture porosity is difficult to estimate but is based on worldwide experience, which, in these types of tectonic environments, suggests values of 0.1 to 0.9 percent (low to high) might be expected which for the purposes of an overall deterministic estimate were narrowed to 0.4 to 0.6 percent. The fracture NTG was varied between formations depending on how much anhydrite or shale is present, however pervasive fracturing throughout the tested intervals is suggested by the high calculated well test PIs.

The fluid properties were based on PVT analysis of fluid samples from AT-1, AT-2, AT-4 and CK-6 for the different fluid types.

Different matrix and fracture oil recovery factors ("RF") were used for each of the fluid types. Matrix recovery in a fractured carbonate with limited production history is very uncertain. SCAL studies on core from well AT-3 suggest mixed USBM wettability with spontaneous imbibition ranging from 17 to 32 percent and suggests recovery using a water displacement process may be appropriate. Matrix recovery factors of 12.5, 14 and 16 percent were used for estimating the total recoverable resources within the medium density oil region and 1.25, 2.5 and 3.5 percent were used for the heavy oil region including an additional drilling development with the medium oil beyond the development assigned reserves and 5, 10 and 12.5 percent were used for the heavy oil region incorporating all heavy oil development. Fracture oil recovery is likely to be very high as the interference tests between the wells show good pressure communication. Fracture recovery factors of 75, 80 and 82.5 percent were used for estimating the total recoverable resources within the medium density oil region; 30, 35 and 60 percent were used for the heavy oil regions including an additional drilling development with the medium oil beyond the development assigned reserves and 60, 70 and 80 percent were used for the heavy oil region incorporating all heavy oil development.

A reserves plus contingent resources summary sheet for each oil density type is presented in Tables 14 to Table 16 at the end of this report. The estimated total resources on these sheets are presented for illustrative purposes only as they are an intermediate step in estimating the reserves and contingent resources and normally should not be combined due to their inherently different risks.

RESERVES ESTIMATES

The crude oil reserves assigned to the Atrush Field are associated with current development plans, which includes production from the currently producing wells and also includes six new wells planned for the Upper and Lower Jurassic. Reserves have been assigned to a core area of the field close to well control as highlighted on Figures 3 to 20 at the end of this report. Based on the well test results it is clear wells are capable of producing at very high initial rates through the fracture system. However, there are significant uncertainties associated with predicting the longer-term future well performance and hence the likely recovery per well. Production from the existing wells appears to show a slight declining API trend, suggesting there is contribution from the heavy oil region. The majority of the reserves though are still associated with the medium-oil region.

Performance from the 11 wells been favorable, resulting in a combined production rate of approximately 40,000 bopd for December 2021. This includes the CK-12 well which was re-completed to an Upper Jurassic producer in April 2021 after producing much lower rates in the Lower Jurassic. Well CK-8 is also completed in the Lower Jurassic and has been a very strong performer so there is likely reasonable contribution from the Lower Jurassic in this well. A secondary gas cap has likely formed in the Upper Jurassic although hopefully with the level of fracturing a stable vertical displacement process will occur. Future production will be dictated by a number of factors including gas breakthrough in the crestal wells due to the expanding gas cap, viscosity effects associated with dropping below the bubble point and any fracture closure or in-situ deposition blocking the fracture system.

Several wells have now broken through to water; though wells AT-2, CK-5 and CK-11 were the first to experience this and have performed well with predictable oil-cut trends. Six future wells are expected to be drilled over the next five years as part of a drill to fill philosophy with it expected that three of the wells will be completed in the Upper Jurassic and the remaining three wells will be completed in the Lower Jurassic Mus Formation.

Recovery factors were generally consistent between the Naokelekan, Upper Sargelu and Lower Sargelu formations and somewhat lower recovery factors were applied to the other formations until further performance data has been acquired. As there is a reasonable amount of uncertainty, undeveloped reserves were also largely checked on the likely recoveries per well as compared to the existing wells to ensure consistency and accounting for potential well interference.

Based on reserves cases and peak production rate for each reserves case the remaining reserves life index for the 1P, 2P and 3P cases are 4.3, 7.6 and 10.9 respectively, which appear reasonable. The reserves estimates are presented in Tables 7, 8, 9 together with the reservoir and fluid properties in Table 10 at the end of this report.

REVENUE FORECASTS

The net present values of the crude oil reserves were based on future production and revenue analyses. All of the revenues and costs presented in this report were presented in United States Dollars ("USD").

The future crude oil revenue was derived by employing the future production forecast for each reserves category and the McDaniel January 1, 2022 forecast of crude oil prices as shown in Table 18. The discount to Brent accounts for the quality differential, transportation tariffs and marketing fees. All of the Atrush oil production is exported via the Khurmala-Fishkabour pipeline to Turkey. ShaMaran has signed a marketing agreement for a differential of $15.78/bbl which is currently being discussed with the government.

The development capital costs are summarized in Table 12 and are based on the budget provided in the Q4 2021 Operating Committee Meeting ("OCM") and expected future well costs, along with earlier operator estimates. Operating costs and general and administrative costs ("G&A") were also based on the Q4 2021 budget, which are in-line with McDaniel estimates and 2021 actuals. Over time, if the development is limited to only the core area, significant G&A savings would likely be made and as such G&A costs were reduced to reflect this scenario. Furthermore, the fixed portion of the operating costs are also likely to be reduced over time due to the nationalization plan of the workforce and removal of the EPF as production rates come off. Variable costs of $30,000 per well per month and a production variable cost of $2.63 per barrel of oil were also included.

Many of the wells are exhibiting natural declines so performance can be extrapolated but for certain wells, the future well productivity has been estimated from the various well tests and the maximum estimated potential reservoir rates for specific zones which is generally based on a 30 PSI drawdown. The timing of the gas breakthrough in crestal wells is very uncertain as well as the timing of water breakthrough and was varied across the reserves categories. The total potential forecast was limited to the current and planned facility capacity dependent on the reserves category. The resulting production forecasts are presented in Figure 21 at the end of this report.

Revenue forecasts were prepared for the proved developed producing ("PDP"), 1P, 2P and 3P reserves cases. The net present value estimates for the proved undeveloped, probable and possible reserves were calculated by subtracting the respective PDP, 1P, 2P and 3P net present values.

A summary of the reserves and net present value estimates were presented in Table 2 and detailed revenue forecasts for the PDP reserves, 1P reserves, 2P reserves and 3P reserves in Tables 3, 4, 5 and 6, respectively, at the end of this report.

CONTINGENT RESOURCES ESTIMATES

Crude oil and natural gas contingent resources were assigned to the Barsarin, Naokelekan, Upper Sargelu, Lower Sargelu, Alan and Mus formations. The contingent resources represent the likely recoverable volumes associated with further phases of development after the current committed development. These are considered to be contingent resources rather than reserves due to the uncertainty over the future development plan, particularly as it relates to the development of the heavy oil region.

The contingent resources were estimated by first estimating the total discovered potentially recoverable resources for each formation summarized in Tables 14 to 16 at the end of this report. The total resources were estimated for three cases, low ("1P+1C"), best estimate ("2P+2C") and high ("3P+3C") case estimates. The 1C, 2C and 3C contingent resources were then determined incrementally by subtracting the 1P, 2P and 3P reserves cases, respectively.

As mentioned previously, the heavy oil total resources was split into two stages of potential development: the first being associated with the future development of the medium oil (East Flank) and an incremental development associated with a heavy oil specific development. The future development of the medium oil (and the volumes associated with the heavy oil as part of this development) have been sub-classified as Development on Hold while the volumes for the heavy oil specific full development have been classified as Development Not Viable.

A summary of the contingent resources are presented in Table 13 on an unrisked basis without accounting for the chance of development. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. The chance of development was estimated to be 70 percent for the medium oil and heavy oil volumes classified as Development on Hold, 10 percent for the heavy oil volumes classified as Development Not Viable and five percent for the natural gas but as many of these factors are extremely difficult to quantify, these are uncertain and must be used with caution. With respect to the heavy oil volumes classified as Development Not Viable, there are currently no plans to further appraise the extended heavy oil development and this would require a significant increase in the oil price to warrant this activity.

A summary of the petroleum-initially-in-place estimates and the crude oil, reserves and contingent resources is presented in Table 17 at the end of this report.

DEFINITIONS AND CLASSIFICATION OF RESERVES AND RESOURCES

The estimates of contingent resources presented in this report have been based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the COGE Handbook and have been presented in accordance with National Instrument 51-101 (NI 51-101).

COGEH Volume 1 was published in June 2002 and provided the framework for the classification of reserves and resources within Canada. COGEH was adopted by the Alberta Securities Commission (ASC) and the Canadian Securities Administrators (CSA) and has been used as a guideline for the evaluation and classification of oil and gas volumes since its publication.

Volume 2 was published in November 2005. This volume contained detailed guidelines for estimating and classifying oil and gas Reserves and Resources. The second edition of Volume 1 was published in September 2007 and contained revisions that ensured Volumes 1 and 2 were consistent, and it also reflected changes prompted by industry feedback after several years of reserves evaluator use. These changes have been incorporated in part to ensure broad alignment between COGEH and the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS). Additional changes have been incorporated within the Second Edition to provide additional clarity on the reporting of resources.

Volume 3 was published in the continuing effort to provide Reserves evaluators with consistent, up to date standards of evaluation procedures in the areas of coalbed methane (CBM), International Properties, and Bitumen and SAGD Reserves and Resources.

In 2014, an addendum to Volume 2 was published, entitled Resources Other Than Reserves, following the framework setup in the Petroleum Resource Management System (PRMS). Although the COGEH is generally applicable to all Resources, previous guidance had focused on Reserves. The guidance provided in the addendum addressed other Resource Classes (referred to as "Resources Other Than Reserves" (ROTR)) and progresses from the estimation of Petroleum Initially-In-Place, through classification as discovered/undiscovered, identification and characterization of recovery technologies and projects, estimation and the economic status of recoverable volumes and description of contingencies and project maturity.

Over time, and with the introduction of the ROTR section of Volume 2, users of the Handbook identified some inconsistencies and redundancies between the three COGEH volumes. Also, new techniques for developing oil and gas Resources have become the norm and because of the new development techniques, new methodologies have been developed for evaluating Resources and Reserves. Furthermore, the once stable regulatory regimes (mainly Crown royalties) have become much more complicated and have undergone "modernization" in an effort by the Crown to capture their "fair share" of oil and gas revenues.

In October 2003, SPEE Calgary Chapter adopted the following official position regarding the use of the Handbook for purposes of preparing oil and gas Reserves evaluations in Canada and that official position continues:

1. The Handbook is, by any reasonable measure, the single most comprehensive set of technical standards available dealing with oil and gas Reserves evaluation practice; and
2. SPEE Calgary Chapter expects all Canadian companies, whether public or private, will use the standards and guidelines set out in the Handbook when preparing, reporting, and disclosing their oil and gas Reserves evaluation results.

Furthermore, COGEH provides a standard other groups such as governments, transmission companies, energy purchasers and financial users, just to name a few, can use in their business models.

The current edition (COGEH – Consolidated Third Edition – January 2022) is an effort to address the inconsistencies, and to consolidate and restructure the materials to reduce redundancies.

The figure below taken from COGEH (Section 1.3.6), illustrates on a high level the resource classification system and project maturity sub-class. The definitions for the pertinent classifications (as per COGEH) for the purposes of this report are detailed on the following pages. The following figure presents a modified version of the previous figure where suggested minimum thresholds are included for the sub-classes.

Resources Classification Framework (COGEH, Section 1.3.6, Figure 1-2)

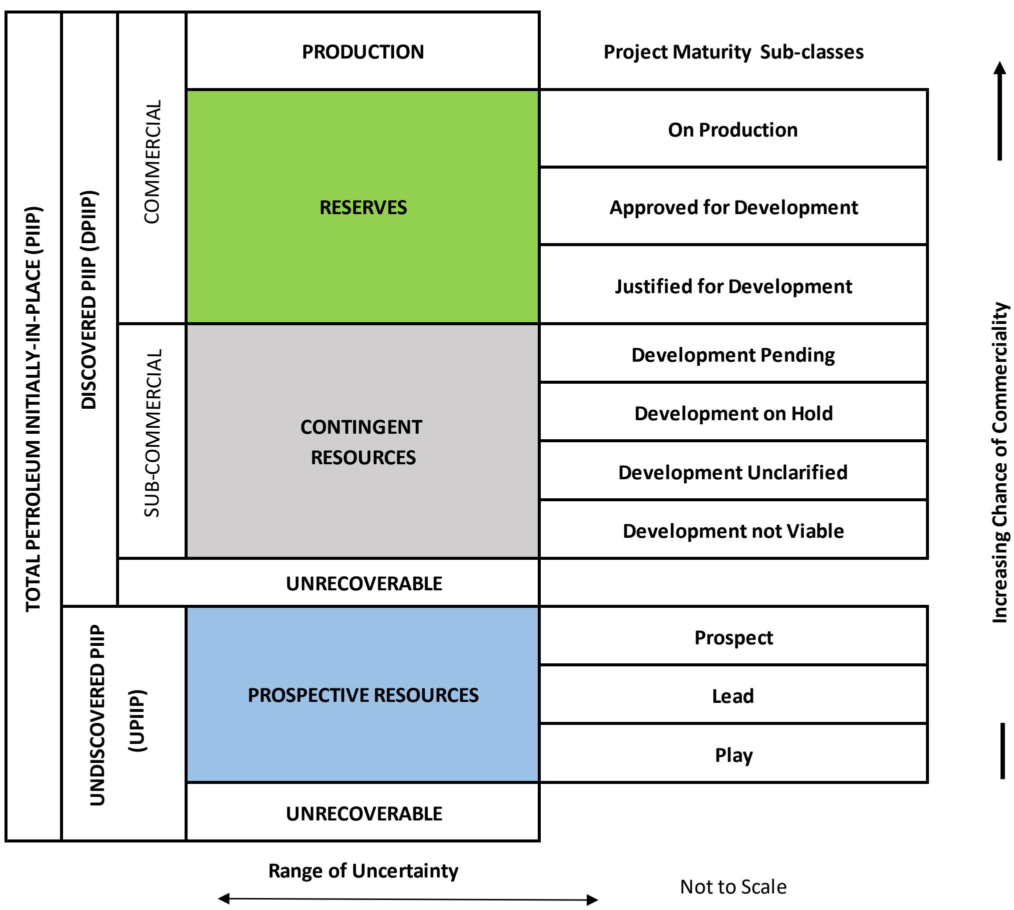
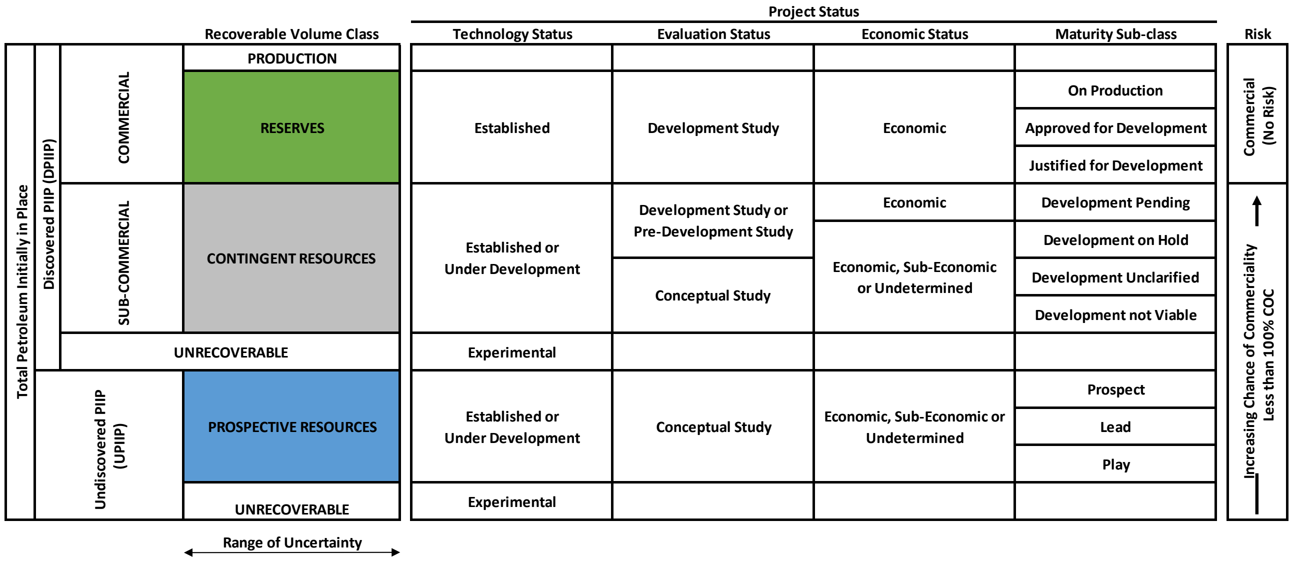


Figure 1-2. PRMS, Sub-classes based on project maturity

Modified Resources Classification Framework – Includes Usual Requirements for Sub-Classes



Definitions of Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified in accordance with the level of certainty associated with the estimates and based on development and production status. To be classified as reserves, estimated recoverable quantities must be associated with projects that have demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.

Reserves are sub-classified based on level of certainty and development status:

Proved Reserves – are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves – are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.

Possible Reserves – are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

Developed Producing Reserves – are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves – are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves – are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared with the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category to which they are assigned.

Additional criteria for the assignment of reserves are contained within Section 1.3 of the COGEH Consolidated Third Edition – January 2022.

Definitions of Resources

Discovered Petroleum Initially-In-Place (equivalent to Discovered Resources) – is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of Discovered Petroleum Initially-In-Place includes production, reserves, and contingent resources; the remainder of the volume is unrecoverable.

Undiscovered Petroleum Initially-In-Place (equivalent to Undiscovered Resources) – is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of Undiscovered Petroleum Initially-In-Place is referred to as Prospective Resources; the remainder is classified as unrecoverable.

Contingent Resources – are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Prospective Resources – are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

In order for contingent or prospective resource volumes to be reclassified as reserves, the projects need to have a chance of commerciality of 100 percent. The *chance of commerciality* is the product of the chance of discovery and chance of development as described below.

Chance of discovery – the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.

Chance of development – the estimated probability that, once discovered, a known accumulation will be commercially developed.

Note that for contingent resources the chance of commerciality is equal to the chance of development. For prospective resource, the chance of commerciality includes both the chance of discovery and development.

The following table displays the ranges for the chance of discovery and development and presents a sample, hypothetical calculation of risked resources.

Table A: Risked Resources Example

	Contingent Resources		Prospective Resources	
	Range	Example	Range	Example
Chance of Development	0 - <100%	80%	0 - <100%	80%
Chance of Discovery	Always 100%	100%	0 - <100%	70%
Risked Resources		1,000 Mbbl X 80% X 100% = 800 Mbbl		2,000 Mbbl X 80% X 70% = 1,120 Mbbl

COGEH (Section 1.3.7.2 Commercial Status) recommends considering the following potential contingencies when determining commerciality:

1. Economic viability of the related development project;
2. A reasonable expectation that there will be a market for the expected sales quantities of production required to justify development;
3. Evidence that the necessary production and transportation facilities are available or can be made available;
4. Evidence that legal, contractual, environmental, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated;

5. A reasonable expectation that all required internal and external approvals will be forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approval for expenditures, etc.

6. Evidence to support a reasonable timetable for development. A reasonable timeframe for the initiation of development depends on the specific circumstances and varies according to the scope of the project. Although five years is recommended as a maximum timeframe for classification of a project as commercial, a longer timeframe could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market related reasons or to meet contractual or strategic objectives.

Recovery technology and the recovery technology status descriptions are required in order to assign contingent or prospective resources.

Established technology – is a recovery method that has been proven to be successful in commercial applications in the subject reservoir and is a prerequisite for assigning reserves.

Technology under development – is a recovery process that has been determined to be technically viable via field test and is being further field tested to determine its economic viability in the subject reservoir. Contingent resources may be assigned if the project provides information that is sufficient and of a quality to meet the requirements for this resource class.

Experimental technology – is a technology that is being field tested to determine the technical viability of applying a recovery process to unrecoverable discovered petroleum initially in place in a subject reservoir. It cannot be used to assign any class of recoverable resource.

Sub-classification of Contingent Resources based on Economic Status

A portion of contingent resources may be associated with projects that are economically viable but have not satisfied all requirements for commerciality. Accordingly, it may be desirable to sub-classify contingent resources by economic status:

Economic Contingent Resources – are those contingent resources that are currently economically recoverable.

Sub-economic Contingent Resources – are those contingent resources that are not currently economically recoverable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is “undetermined”.

In examining the economic viability, the same fiscal conditions should be applied to contingent resources as in the estimation of reserves, i.e. specified economic conditions, which are generally accepted as being reasonable.

Project Evaluation Scenario Status

A project evaluation scenario is required before contingent or prospective resources can be estimated. The project evaluation scenario status is an assessment of the level of planning that has gone into the project in question and another way of adding clarity to the reader how advanced the project is and what level of detail went into the estimates.

Conceptual – A conceptual or scoping study is the initial stage of the development of a project scenario, with limited detail and typically based on limited information. It may be pre-discovery or an objective may be to determine whether to acquire ownership rights. There will usually be limited information available and major parameters will be mostly assumed.

Pre-Development – A pre-development study is an intermediate step in the development of a project evaluation scenario. The amount of information that is available for the reservoir of interest is greater than for a conceptual study. In particular, the petroleum initially in place has been reasonably well defined and the remaining uncertainty lies largely in the recovery factor and the economic viability.

Development – A development study is the most detailed step in the development of a project evaluation scenario. It is based on a detailed geological and engineering study and economic analysis of information on the specific project and provides sufficient information for the creation of a development plan, from which a development decision can be made.

Project Maturity Status: Project Maturity Sub-categories

Contingent resources can be sub-classified based on project maturity. COGEH (Section 1.3.6 Project Maturity Sub-Classes), discusses what the typical progression is, as follows:

1) Initial assessment to confirm the reservoir as a known accumulation with the potential for development. During this process, the project maturity may be **Development Unclarified** while additional information, in particular test or pilot data, is being acquired. For conventional accumulations, this data-gathering stage may be a short time (e.g., with a drill stem test prior to rig release), but for unconventional accumulations, this may take considerable time, even years, and involve pilot tests; and

2) Once the appropriate information to pass beyond development unclarified has been collected and analyzed appropriately, a project may be classified as either:

- **Development Pending**, where resolution of the final conditions for development is being actively pursued (high chance of development). (If a project cannot be developed within a reasonable timeframe, consideration should be given to reclassification as development on hold); or

- **Development On Hold**, where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; or

- **Development Not Viable**, where no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

A flow chart showing the various project maturity sub-classes is shown below. The dashed lines indicate that Unclarified, Development Pending, or On Hold can be maintained only for a limited time, after which reclassification to Not Viable may be appropriate.

Project Maturity Sub-Classes (COGEH, Section 1.4.7.2.2.9 Project Maturity Sub-Classes for Contingent Resources, Figure 1-5)

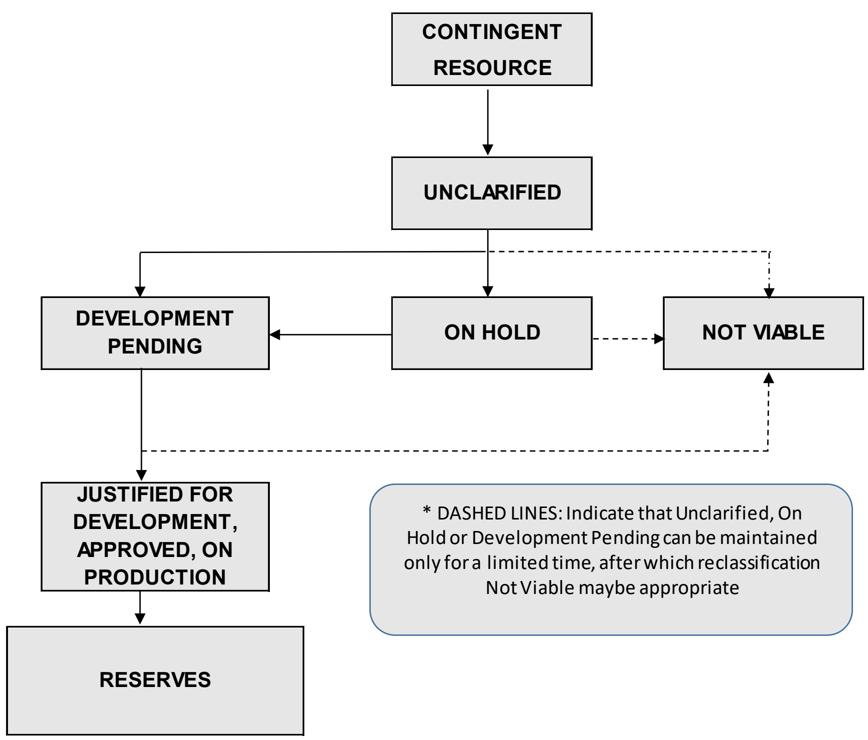


Figure 1-5 Flow Chart Illustrating the Relationship Among the Project Maturity Sub-Classes for Contingent Resources

Sub-classification of Prospective Resources based on Project Maturity Status

Similarly, prospective resources can be sub-classified based on project maturity. COGEH (Section 1.4.7.2.3.2 Project Maturity Sub-Classes for Prospective Resources), discusses what the typical progression is, as follows:

Play - A family of geologically similar fields, discoveries, prospects and leads.

Lead - A potential accumulation within a play that requires more data acquisition and/or evaluation in order to be classified as a prospect.

Prospect - A potential accumulation within a play that is sufficiently well defined to represent a viable drilling target.

Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification. Contingent and prospective resources estimates involve additional risks not reflected within reserves estimates, specifically the risk of not achieving commerciality and exploration risk, respectively.

Prices: McDaniel January 1, 2022
Eff. Date: December 31, 2021
Currency: USD

Table 1

ShaMaran Petroleum Corp.
Well Test Summary
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Well	DST#	Top (m md)	Base (m md)	Top (m ss)	Base (m ss)	Open Interval (m)	Open Formation	Fluid Type	Max Rate (bpd)	Wellsite API (deg)	API Remarks	Other Remarks
AT-1	9	1,168	1,180	-52	-40	12	Barsarin/Naokelekan	Oil	2,432	26.5	PVT 24.4 deg API	N2 lift post acid
AT-1	8	1,245	1,257	24	36	12	U Sargelu	Oil	2,708	26.5	PVT 25.8 deg API	N2 lift post acid
AT-1	7	1,340	1,352	119	131	12	L Sargelu	Oil	1,253	26.5	-	N2 lift post acid
AT-1	6	1,475	1,525	254	304	50	Mus	Oil	N/R	6	Heavy Oil (Tar)	-
AT-1	5	1,745	1,757	524	536	12	Butmah	Water	890	Water	Trace of Oil	-
AT-2	5	1,247	1,261	-68	-81	14	Naokelekan	Oil	15,829	26.4	-	ESP (surface constrained)
AT-2	4	1,310	1,350	-127	-165	40	U Sargelu	Oil	14,670	27.7	-	ESP (surface constrained)
AT-2	3	1,380	1,415	-193	-227	35	L Sargelu	Oil	11,714	23.5	-	ESP (surface constrained)
AT-2	2	1,443	1,453	-254	-263	10	Alan	Oil	620	10 to 11	BHS 22 deg API (PVT)	N2 lift post acid
AT-2	1	1,469	1,570	-279	-376	101	Alan/Mus	Oil	1,450	8 to 9	BHS 22 deg API (PVT)	N2 lift post acid
AT-3	3	1,272	1,290	-239	-257	18	Naokelekan	Oil	600	12 to 14	No PVT	ESP
AT-3	2	1,396	1,444	-361	-408	48	U & L Sargelu	Oil	1,500	10 to 17	No PVT	ESP
AT-3	1	1,536	1,575	-498	-536	39	Mus	Water	1,500	Water	-	ESP + 1-6% Viscous Oil
AT-3	Retest	1,272	1,444	-239	-408	48	Naokelekan / U & L Sargelu	Oil	3,000	14	-	ESP
AT-4	3	1,875	1,995	150	97	120	Chia Gara Transition Beds	Oil	5,255	20 to 28	-	ESP
AT-4	2	2,194	2,410	-15	-152	216	Barsarin/Naokelekan	Oil	3,804	22 to 28	PVT 26.2 deg API	ESP
AT-4	1	2,600	2,612	-274	-282	12	Barsarin	-	-	-	Tight	Not Tested
CK-5	3	1,355	1,367	34	25	12	Naokelekan	Oil	2,100	24.7	-	ESP
CK-5	2	1,460	1,616	-45	-163	156	Sargelu	Oil	9,200	24.4	-	ESP
CK-5	1	1,800	1,824	-302	-320	24	Mus	Oil	1,500	13.1	-	ESP
CK-6	3	1,416	1,440	-120	-134	24	Naokelekan	Oil	7,331	26.0	-	ESP
CK-6	2	1,650	1,712	-275	-321	62	L Sargelu	Oil	1,700	13.0	Likely Emulsion	ESP
CK-6	1	1,870	1,882	-450	-460	12	Alan	Oil	-	-	Heavy Oil - No Flow	ESP & N2
CK-8	2	1,664	1,723	-7	-43	59	Sargelu	Oil	8250	26.6	-	ESP
CK-8	1	1,892	1,916	-149	-164	24	Mus	Oil	4375	23.9	-	ESP

(1) All tests conducted after acidizing the interval
(2) Aggregating these test rates to determine an overall well potential would be misleading due to fracturing.
(3) The wellsite API measurements may be unreliable due to the tendancy of the more viscous oil to form tight emulsions when using ESPs
(4) Depths below subsea are negative

ShaMaran Petroleum Corp.
Summary of Reserves and Net Present Values
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Summary of Reserves [1]

Reserves Category	Light/Medium Crude Oil [2] Property Gross Mbbl	Light/Medium Crude Oil [2] Company Gross Mbbl	Light/Medium Crude Oil [2] Company Net Mbbl	Heavy Crude Oil [2] Property Gross Mbbl	Heavy Crude Oil [2] Company Gross Mbbl	Heavy Crude Oil [2] Company Net Mbbl
Proved Developed Producing Reserves	33,865	9,347	5,189	8,215	2,267	1,259
Proved Developed Non-Producing Reserves	-	-	-	-	-	-
Proved Developed Reserves	33,865	9,347	5,189	8,215	2,267	1,259
Proved Undeveloped Reserves	17,238	4,758	2,588	3,196	882	478
Total Proved Reserves	**51,103**	**14,104**	**7,778**	**11,410**	**3,149**	**1,737**
Total Probable Reserves	34,753	9,592	3,917	12,897	3,560	1,574
Total Proved + Probable Reserves	**85,856**	**23,696**	**11,694**	**24,307**	**6,709**	**3,311**
Total Possible Reserves	37,061	10,229	3,845	12,300	3,395	1,317
Total Proved + Probable + Possible Reserves	**122,917**	**33,925**	**15,539**	**36,607**	**10,104**	**4,628**

Reserves Category	Total Crude Oil Property Gross Mbbl	Total Crude Oil Company Gross Mbbl	Total Crude Oil Company Net Mbbl
Proved Developed Producing Reserves	42,079	11,614	6,448
Proved Developed Non-Producing Reserves	-	-	-
Proved Developed Reserves	42,079	11,614	6,448
Proved Undeveloped Reserves	20,434	5,640	3,066
Total Proved Reserves	**62,513**	**17,254**	**9,514**
Total Probable Reserves	47,650	13,151	5,491
Total Proved + Probable Reserves	**110,163**	**30,405**	**15,005**
Total Possible Reserves	49,361	13,624	5,162
Total Proved + Probable + Possible Reserves	**159,524**	**44,029**	**20,167**

Summary of Company Share of Net Present Values

Reserves Category	$M US Dollars 0.0%	5.0%	10.0%	15.0%	20.0%
Proved Developed Producing Reserves	177,296	162,315	149,873	139,397	130,467
Proved Developed Non-Producing Reserves	-	-	-	-	-
Proved Developed Reserves	177,296	162,315	149,873	139,397	130,467
Proved Undeveloped Reserves	61,405	47,870	37,702	29,927	23,886
Total Proved Reserves	**238,701**	**210,185**	**187,576**	**169,324**	**154,353**
Total Probable Reserves	158,240	127,350	105,607	89,735	77,777
Total Proved + Probable Reserves	**396,941**	**337,535**	**293,183**	**259,059**	**232,129**
Total Possible Reserves	102,485	65,356	45,442	33,974	26,907
Total Proved + Probable + Possible Reserves	**499,426**	**402,891**	**338,625**	**293,033**	**259,036**

Summary of Company Share of Unit Values

Reserves Category	$/bbl US Dollars 0.0%	5.0%	10.0%	15.0%	20.0%
Proved Developed Producing Reserves	15.27	13.98	12.90	12.00	11.23
Proved Developed Non-Producing Reserves	-	-	-	-	-
Proved Developed Reserves	15.27	13.98	12.90	12.00	11.23
Proved Undeveloped Reserves	10.89	8.49	6.69	5.31	4.24
Total Proved Reserves	**13.83**	**12.18**	**10.87**	**9.81**	**8.95**
Total Probable Reserves	12.03	9.68	8.03	6.82	5.91
Total Proved + Probable Reserves	**13.06**	**11.10**	**9.64**	**8.52**	**7.63**
Total Possible Reserves	7.52	4.80	3.34	2.49	1.98
Total Proved + Probable + Possible Reserves	**11.34**	**9.15**	**7.69**	**6.66**	**5.88**

(1) Company gross reserves are based on ShaMaran's 27.6 percent working interest share of the property gross reserves. Company Net reserves are based on Company share of total Cost and Profit Revenues. Note, as the government pays income taxes on behalf of Company out of the government's profit oil share, the net reserves were based on the effective pre-tax profit revenues by adjusting for the tax rate.

(2) Fluid type is classifed according to COGEH: Light/Medium Oil is based on density less than 920 kg/m^3 and Heavy Oil is between 920 and 1,000 kg/m^3. Hence the reserves presented in Table 8 are considered Light/Medium Oil and in Table 9, Heavy Oil.

ShaMaran Petroleum Corp.
Forecast of Production and Revenues
Forecast Prices and Costs as of December 31, 2021
Proved Developed Producing Reserves
Atrush Field - Kurdistan Region

Property Gross Share of Production and Gross Revenues

Year	Well Count	Avg. Daily Rate Bopd	Annual Volume Mbbl	Crude Oil Price US$/bbl	Sales Revenue US$MM
2022	11	33,730	12,311	59.22	729.08
2023	11	25,417	9,277	54.09	501.80
2024	11	19,057	6,956	51.85	360.62
2025	11	13,945	5,090	53.20	270.78
2026	10	10,205	3,725	54.58	203.29
2027	10	7,468	2,726	55.99	152.60
2028	9	5,465	1,995	57.42	114.53
2029	-	-	-	-	-
2030	-	-	-	-	-
2031	-	-	-	-	-
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
Rem.			-	-	-
Total			**42,079**	**55.44**	**2,332.70**

Property Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Oil Revenues US$MM	Profit Oil Revenues US$MM
2022	72.91	10.0	81.04	6.58	-	55.42	8.22	511.50	262.47	393.70
2023	50.18	10.0	64.01	6.90	-	-	8.38	379.22	180.65	270.97
2024	36.06	10.0	58.94	8.47	-	-	8.55	257.07	129.82	194.74
2025	27.08	10.0	54.91	10.79	-	-	8.72	180.07	97.48	146.22
2026	20.33	10.0	48.19	12.94	-	-	8.89	125.88	73.18	109.78
2027	15.26	10.0	42.25	15.50	-	-	9.07	86.02	54.94	82.40
2028	11.45	10.0	36.85	18.47	-	-	9.25	56.97	41.23	61.85
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**233.27**	**-**	**386.19**	**-**	**-**	**55.42**	**61.09**	**1,596.73**	**839.77**	**1,259.66**

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Total Cost Revenues US$MM	Total Profit Revenues US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Total Bonuses US$MM	Capacity Building Value US$MM	Carry Repayment US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2022	3,398	1,908	72.44	34.77	22.37	15.30	2.27	-	10.43	8.81	65.66	62.61
2023	2,560	1,438	49.86	23.93	17.67	-	2.31	-	7.18	-	46.63	40.42
2024	1,920	1,062	35.83	16.50	16.27	-	2.36	-	4.95	-	28.76	22.66
2025	1,405	770	26.90	12.06	15.16	-	2.41	-	3.62	-	17.79	12.74
2026	1,028	561	20.20	8.92	13.30	-	2.45	-	2.68	-	10.69	6.96
2027	752	409	15.16	6.64	11.66	-	2.50	-	1.99	-	5.64	3.34
2028	551	299	11.38	4.96	10.17	-	2.55	-	1.49	-	2.13	1.15
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	**11,614**	**6,448**	**231.78**	**107.79**	**106.59**	**15.30**	**16.86**	**-**	**32.34**	**8.81**	**177.30**	**149.87**

ShaMaran Petroleum Corp.
Forecast of Production and Revenues
Forecast Prices and Costs as of December 31, 2021
Total Proved Reserves
Atrush Field - Kurdistan Region

Property Gross Share of Production and Gross Revenues

Year	Well Count	Avg. Daily Rate Bopd	Annual Volume Mbbl	Crude Oil Price US$/bbl	Sales Revenue US$MM
2022	11	34,385	12,550	59.22	743.24
2023	12	30,656	11,190	54.09	605.25
2024	16	28,170	10,282	51.85	533.07
2025	17	23,831	8,698	53.20	462.74
2026	17	18,269	6,668	54.58	363.93
2027	17	13,441	4,906	55.99	274.66
2028	16	9,889	3,609	57.42	207.26
2029	15	7,276	2,656	58.88	156.37
2030	15	5,353	1,954	60.38	117.97
2031	-	-	-	-	-
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
Rem.			-	-	-
Total			**62,513**	**55.42**	**3,464.49**

Property Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Oil Revenues US$MM	Profit Oil Revenues US$MM
2022	74.32	10.0	81.67	6.51	-	102.13	6.95	478.17	267.57	401.35
2023	60.52	10.0	74.47	6.66	-	26.52	7.09	436.64	217.89	326.83
2024	53.31	10.0	74.97	7.29	-	27.05	7.23	370.51	191.91	287.86
2025	46.27	10.0	72.44	8.33	-	13.80	7.37	322.86	166.59	249.88
2026	36.39	10.0	65.26	9.79	-	-	7.52	254.76	131.02	196.52
2027	27.47	10.0	61.45	12.53	-	-	7.67	178.07	98.88	148.32
2028	20.73	10.0	54.37	15.06	-	-	7.82	124.34	74.61	111.92
2029	15.64	10.0	48.03	18.09	-	-	7.98	84.72	56.29	84.44
2030	11.80	10.0	42.22	21.61	-	-	8.14	55.82	42.47	63.70
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**346.45**	**-**	**574.88**	**-**	**-**	**169.50**	**67.76**	**2,305.90**	**1,247.22**	**1,870.83**

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Total Cost Revenues US$MM	Total Profit Revenues US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Total Bonuses US$MM	Capacity Building Value US$MM	Carry Repayment US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2022	3,464	1,945	73.85	35.45	22.54	28.19	1.92	-	10.63	8.81	54.83	52.28
2023	3,088	1,734	60.14	28.87	20.55	7.32	1.96	-	8.66	-	50.51	43.78
2024	2,838	1,574	52.97	24.55	20.69	7.47	1.99	-	7.36	-	40.00	31.52
2025	2,401	1,315	45.98	20.57	19.99	3.81	2.03	-	6.17	-	34.54	24.74
2026	1,840	999	36.16	15.72	18.01	-	2.08	-	4.72	-	27.08	17.63
2027	1,354	730	27.29	11.62	16.96	-	2.12	-	3.49	-	16.35	9.68
2028	996	535	20.59	8.67	15.01	-	2.16	-	2.60	-	9.50	5.11
2029	733	393	15.54	6.51	13.26	-	2.20	-	1.95	-	4.64	2.27
2030	539	289	11.72	4.91	11.65	-	2.25	-	1.47	-	1.26	0.56
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,254**	**9,514**	**344.23**	**156.87**	**158.67**	**46.78**	**18.70**	**-**	**47.06**	**8.81**	**238.70**	**187.58**

ShaMaran Petroleum Corp.
Forecast of Production and Revenues
Forecast Prices and Costs as of December 31, 2021
Total Proved + Probable Reserves
Atrush Field - Kurdistan Region

Property Gross Share of Production and Gross Revenues

Year	Well Count	Avg. Daily Rate Bopd	Annual Volume Mbbl	Crude Oil Price US$/bbl	Sales Revenue US$MM
2022	11	39,358	14,366	59.22	850.73
2023	12	38,541	14,067	54.09	760.91
2024	16	39,420	14,388	51.85	745.97
2025	17	36,882	13,462	53.20	716.15
2026	17	31,833	11,619	54.58	634.14
2027	17	26,762	9,768	55.99	546.88
2028	16	22,499	8,212	57.42	471.56
2029	15	18,916	6,904	58.88	406.55
2030	15	15,903	5,804	60.38	350.46
2031	14	13,370	4,880	61.90	302.07
2032	13	11,240	4,103	63.45	260.33
2033	12	7,094	2,589	65.04	168.40
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
Rem.			-	-	-
Total			**110,163**	**56.41**	**6,214.15**

Property Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Oil Revenues US$MM	Profit Oil Revenues US$MM
2022	85.07	10.0	86.44	6.02	-	102.13	-	577.09	306.26	459.40
2023	76.09	10.0	87.74	6.24	-	26.52	-	570.56	273.93	410.89
2024	74.60	10.0	91.87	6.38	-	27.05	6.50	545.95	268.55	402.82
2025	71.62	10.0	91.50	6.80	-	13.80	6.63	532.60	257.81	386.72
2026	63.41	10.0	85.24	7.34	-	-	6.77	478.72	197.51	373.22
2027	54.69	10.0	81.57	8.35	-	-	6.90	403.71	88.48	403.71
2028	47.16	10.0	78.25	9.53	-	-	7.04	339.11	85.29	339.11
2029	40.66	10.0	75.53	10.94	-	-	7.18	283.18	82.71	283.18
2030	35.05	10.0	73.33	12.63	-	-	7.33	234.76	80.66	234.76
2031	30.21	10.0	66.55	13.64	-	-	7.47	197.84	74.02	197.84
2032	26.03	10.0	59.96	14.61	-	-	7.62	166.72	67.58	166.72
2033	16.84	10.0	40.16	15.51	-	-	7.77	103.63	47.93	103.63
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**621.41**	**-**	**918.14**	**-**	**-**	**169.50**	**71.22**	**4,433.87**	**1,830.72**	**3,762.01**

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Total Cost Revenues US$MM	Total Profit Revenues US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Total Bonuses US$MM	Capacity Building Value US$MM	Carry Repayment US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2022	3,965	2,227	84.53	40.57	23.86	28.19	-	-	12.17	8.81	69.70	66.45
2023	3,883	2,180	75.60	36.28	24.22	7.32	-	-	10.88	-	69.46	60.21
2024	3,971	2,179	74.12	33.29	25.36	7.47	1.80	-	9.99	-	62.81	49.49
2025	3,715	2,001	71.16	30.25	25.25	3.81	1.83	-	9.08	-	61.44	44.01
2026	3,207	1,592	54.51	27.77	23.53	-	1.87	-	8.33	-	48.55	31.62
2027	2,696	1,039	24.42	28.91	22.51	-	1.91	-	8.67	-	20.24	11.98
2028	2,267	897	23.54	23.95	21.60	-	1.94	-	7.18	-	16.76	9.02
2029	1,906	780	22.83	19.81	20.85	-	1.98	-	5.94	-	13.87	6.78
2030	1,602	684	22.26	16.32	20.24	-	2.02	-	4.90	-	11.43	5.08
2031	1,347	588	20.43	13.71	18.37	-	2.06	-	4.11	-	9.60	3.88
2032	1,132	506	18.65	11.53	16.55	-	2.10	-	3.46	-	8.07	2.97
2033	715	332	13.23	7.16	11.08	-	2.15	-	2.15	-	5.01	1.68
2034	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	**30,405**	**15,005**	**505.28**	**289.56**	**253.41**	**46.78**	**19.657**	**-**	**86.87**	**8.81**	**396.94**	**293.18**

ShaMaran Petroleum Corp.
Forecast of Production and Revenues
Forecast Prices and Costs as of December 31, 2021
Total Proved + Probable + Possible Reserves
Atrush Field - Kurdistan Region

Property Gross Share of Production and Gross Revenues

Year	Well Count	Avg. Daily Rate Bopd	Annual Volume Mbbl	Crude Oil Price US$/bbl	Sales Revenue US$MM
2022	11	39,566	14,441	59.22	855.23
2023	12	42,539	15,527	54.09	839.85
2024	16	44,232	16,145	51.85	837.03
2025	17	42,486	15,507	53.20	824.97
2026	17	38,109	13,910	54.58	759.17
2027	17	33,466	12,215	55.99	683.86
2028	17	29,388	10,727	57.42	615.93
2029	17	25,808	9,420	58.88	554.68
2030	17	22,663	8,272	60.38	499.45
2031	16	19,902	7,264	61.90	449.66
2032	15	17,477	6,379	63.45	404.79
2033	15	15,348	5,602	65.04	364.35
2034	14	13,478	4,919	66.66	327.91
2035	13	11,836	4,320	68.30	295.08
2036	12	10,394	3,794	69.99	265.51
Rem.			11,082	74.07	820.89
Total			**159,524**	**58.91**	**9,398.34**

Property Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Oil Revenues US$MM	Profit Oil Revenues US$MM
2022	85.52	10.0	86.64	6.00	-	102.13	-	580.93	307.88	461.82
2023	83.98	10.0	91.65	5.90	-	26.52	-	637.69	302.34	453.52
2024	83.70	10.0	96.67	5.99	-	27.05	-	629.61	301.33	452.00
2025	82.50	10.0	97.21	6.27	-	13.80	-	631.47	296.99	445.48
2026	75.92	10.0	91.76	6.60	-	-	-	591.48	96.76	586.49
2027	68.39	10.0	88.68	7.26	-	-	-	526.79	88.68	526.79
2028	61.59	10.0	86.04	8.02	-	-	-	468.30	86.04	468.30
2029	55.47	10.0	83.82	8.90	-	-	-	415.40	83.82	415.40
2030	49.95	10.0	81.96	9.91	-	-	-	367.55	81.96	367.55
2031	44.97	10.0	80.06	11.02	-	-	7.47	317.16	87.53	317.16
2032	40.48	10.0	78.47	12.30	-	-	7.62	278.22	86.09	278.22
2033	36.43	10.0	77.16	13.77	-	-	7.77	242.98	84.93	242.98
2034	32.79	10.0	76.09	15.47	-	-	7.93	211.10	84.02	211.10
2035	29.51	10.0	75.25	17.42	-	-	8.09	182.23	83.34	182.23
2036	26.55	10.0	74.62	19.67	-	-	8.25	156.09	82.87	156.09
Rem.	82.09	10.0	260.05	23.47	-	-	34.68	444.07	291.45	447.35
Total	**939.83**	**-**	**1,526.14**	**-**	**-**	**169.50**	**81.81**	**6,681.06**	**2,446.03**	**6,012.47**

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Total Cost Revenues US$MM	Total Profit Revenues US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Total Bonuses US$MM	Capacity Building Value US$MM	Carry Repayment US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2022	3,986	2,238	84.98	40.79	23.91	28.19	-	-	12.24	8.81	70.24	66.97
2023	4,285	2,406	83.45	40.02	25.30	7.32	-	-	12.01	-	78.85	68.34
2024	4,456	2,437	83.17	37.01	26.68	7.47	-	-	11.10	-	74.93	59.04
2025	4,280	2,290	81.97	34.15	26.83	3.81	-	-	10.24	-	75.23	53.89
2026	3,839	1,392	26.71	42.21	25.33	-	-	-	12.66	-	30.93	20.14
2027	3,371	1,206	24.48	36.92	24.48	-	-	-	11.07	-	25.84	15.30
2028	2,961	1,067	23.75	32.17	23.75	-	-	-	9.65	-	22.52	12.12
2029	2,600	950	23.13	28.10	23.13	-	-	-	8.43	-	19.67	9.62
2030	2,283	850	22.62	24.58	22.62	-	-	-	7.37	-	17.21	7.65
2031	2,005	787	24.16	21.03	22.10	-	2.06	-	6.31	-	14.72	5.95
2032	1,761	712	23.76	18.37	21.66	-	2.10	-	5.51	-	12.86	4.73
2033	1,546	647	23.44	16.00	21.30	-	2.15	-	4.80	-	11.20	3.74
2034	1,358	591	23.19	13.89	21.00	-	2.19	-	4.17	-	9.72	2.95
2035	1,192	542	23.00	12.00	20.77	-	2.23	-	3.60	-	8.40	2.32
2036	1,047	498	22.87	10.30	20.59	-	2.28	-	3.09	-	7.21	1.81
Rem.	3,059	1,554	80.44	29.72	71.77	-	9.57	-	8.92	-	19.90	4.03
Total	**44,029**	**20,167**	**675.10**	**437.26**	**421.21**	**46.78**	**22.58**	**-**	**131.18**	**8.81**	**499.43**	**338.62**

Currency: USD

ShaMaran Petroleum Corp.
Crude Oil Reserves Summary - Property Gross Values
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Oil Density	Medium	Heavy	Total Atrush
Proved Developed Producing Reserves			
Oil Initially-in-Place, Mbbl	550,261	479,941	1,030,203
Recovery Factor, %	15.6	2.2	9.3
Original Recoverable, Mbbl	85,574	10,369	95,943
Cumulative Recovery, Mbbl	51,709	2,155	53,863
Remaining Recoverable, Mbbl	33,865	8,215	42,079
Total Proved Reserves			
Oil Initially-in-Place, Mbbl	550,261	479,941	1,030,203
Recovery Factor, %	18.7	2.8	11.3
Original Recoverable, Mbbl	102,812	13,565	116,377
Cumulative Recovery, Mbbl	51,709	2,155	53,863
Remaining Recoverable, Mbbl	51,103	11,410	62,513
Total Probable Reserves	34,753	12,897	47,650
Total Proved + Probable Reserves			
Oil Initially-in-Place, Mbbl	613,285	515,237	1,128,522
Recovery Factor, %	22.4	5.1	14.5
Original Recoverable, Mbbl	137,565	26,462	164,026
Cumulative Recovery, Mbbl	51,709	2,155	53,863
Remaining Recoverable, Mbbl	85,856	24,307	110,163
Total Possible Reserves	37,061	12,300	49,361
Total Proved + Probable + Possible Reserves			
Oil Initially-in-Place, Mbbl	679,441	570,346	1,249,786
Recovery Factor, %	25.7	6.8	17.1
Original Recoverable, Mbbl	174,626	38,762	213,388
Cumulative Recovery, Mbbl	51,709	2,155	53,863
Remaining Recoverable, Mbbl	122,917	36,607	159,524

Prices: McDaniel January 1, 2022
Eff. Date: December 31, 2021
Currency: USD

Table 8

ShaMaran Petroleum Corp.
Crude Oil Reserves Summary - Medium Oil
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

	Barsarin		Naokelekan		Upper Sargelu		Lower Sargelu		Alan		Mus		Total
Zone	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Field**
Reservoir Parameters													
Water Saturation, %	25.0	10.0	15.0	10.0	25.0	10.0	25.0	10.0	20.0	10.0	25.0	10.0	
Oil Shrinkage, frac	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.9	0.9	0.85	0.85	
Net to Gross Ratio, frac	0.07	0.47	0.32	0.56	0.25	1.00	0.67	1.00	0.12	0.3	0.54	1.00	
Proved Developed Producing Reserves													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1000 ac-ft	925	925	703	703	1,095	1,095	382	382	630.0	630.0	460	460	
Area, acres	5,341	5,341	4,715	4,715	4,149	4,149	3,027	3,027	2,515	2,515	1,583	1,583	
Oil Initially-in-Place, Mbbl	24,686	10,379	88,553	9,400	100,469	32,666	122,801	11,405	31,543	4,361	103,009	10,990	550,261
Recovery Factor, %	5.0	60.0	10.5	70.0	10.5	70.0	10.5	70.0	1.0	15.0	2.5	40.0	15.6
Original Recoverable, Mbbl	1,234	6,227	9,298	6,580	10,549	22,866	12,894	7,983	315.4	654.1	2,575	4,396	85,574
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													33,865
Total Proved Reserves													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1000 ac-ft	925	925	703	703	1,095	1,095	382	382	630	630	460	460	
Area, acres	5,341	5,341	4,715	4,715	4,149	4,149	3,027	3,027	2,515.0	2,515	1,583	1,583	
Oil Initially-in-Place, Mbbl	24,686	10,379	88,553	9,400	100,469	32,666	122,801	11,405	31,542.6	4,360.9	103,009	10,990	550,261
Recovery Factor, %	7.5	62.5	12.5	75.0	12.5	75.0	12.5	75.0	1.0	15.0	6.0	75.0	18.7
Original Recoverable, Mbbl	1,851	6,487	11,069	7,050	12,559	24,500	15,350	8,554	315.4	654.1	6,181	8,243	102,812
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													51,103
Total Proved + Probable Reserves													
Porosity, %	8.4	0.5	7.4	0.5	7.8	0.6	10.2	0.6	8.3	0.5	8.8	0.5	
Oil-Down-To, m ss	-233	-233	-233	-233	-233	-233	-233	-233	-	-	-215	-215	
Gross Rock Volume, 1000 ac-ft	998	998	746	746	1,149	1,149	392	392	634.7	635	460	460	
Area, acres	5,811	5,811	5,043	5,043	4,357	4,357	3,121	3,121	2,549.5	2,550	1,583	1,583	
Oil Initially-in-Place, Mbbl	28,042	14,001	98,849	12,460	110,973	41,133	132,667	14,046	33,454	5,492	108,431	13,738	613,285
Recovery Factor, %	10.0	65.0	14.0	80.0	14.0	80.0	14.0	80.0	2.0	20.0	10.0	80.0	22.4
Original Recoverable, Mbbl	2,804	9,101	13,839	9,968	15,536	32,906	18,573	11,237	669.1	1,098.5	10,843	10,990	137,565
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													85,856
Total Proved + Probable + Possible Reserves													
Porosity, %	8.9	0.6	7.7	0.6	8.2	0.7	10.7	0.7	8.7	0.6	9.2	0.6	
Gross Rock Volume, 1000 ac-ft	1,072	1,072	788	788	1,203	1,203	402	402	639.5	639	460	460	
Area, acres	6,280	6,280	5,371	5,371	4,565	4,565	3,214	3,214	2,584.0	2,584	1,583	1,583	
Oil Initially-in-Place, Mbbl	31,604	18,034	109,708	15,804	121,998	50,244	142,872	16,807	35,391	6,640	113,852	16,485	679,441
Recovery Factor, %	10.0	70.0	16.0	82.5	16.0	82.5	16.0	82.5	3.0	25.0	12.5	82.5	25.7
Original Recoverable, Mbbl	3,160	12,624	17,553	13,039	19,520	41,451	22,860	13,866	1,061.7	1,660.1	14,232	13,600	174,626
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													122,917

Currency: USD

ShaMaran Petroleum Corp.
Crude Oil Reserves Summary - Heavy Oil
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

	Barsarin		Naokelekan		Upper Sargelu		Lower Sargelu		Alan		Mus		Total
Zone	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Field**
Reservoir Parameters													
Water Saturation, %	25.0	10.0	15.0	10.0	25.0	10.0	25.0	10.0	-	-	25.0	10.0	
Oil Shrinkage, frac	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	-	-	0.91	0.90	
Net to Gross Ratio, frac	0.07	0.42	0.32	0.63	0.25	1.00	0.67	1.00	-	-	0.54	1.00	
Proved Developed Producing Reserves													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	-	-	8.3	0.4	
Gross Rock Volume, 1000 ac-ft	421	421	386	386	476	476	342	342	-	-	805	805	
Area, acres	7,421	7,421	6,909	6,909	6,397	6,397	5,405	5,405	-	-	3,649	3,649	
Oil Initially-in-Place, Mbbl	11,993	4,574	52,709	6,294	47,315	15,384	118,891	11,042	-	-	191,492	20,246	479,941
Recovery Factor, %	-	-	1.0	25.0	1.0	25.0	1.0	25.0	-	-	-	-	2.2
Original Recoverable, Mbbl	-	-	527	1,574	473	3,846	1,189	2,760	-	-	-	-	10,369
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													8,215
Total Proved Reserves													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	-	-	8.3	0.4	
Gross Rock Volume, 1000 ac-ft	421	421	386	386	476	476	342	342	-	-	805	805	
Area, acres	7,421	7,421	6,909	6,909	6,397	6,397	5,405	5,405	-	-	3,649	3,649	
Oil Initially-in-Place, Mbbl	11,993	4,574	52,709	6,294	47,315	15,384	118,891	11,042	-	-	191,492	20,246	479,941
Recovery Factor, %	-	-	1.25	30.0	1.25	30.0	1.25	30.0	-	-	-	5.0	2.8
Original Recoverable, Mbbl	-	-	659	1,888	591	4,615	1,486	3,313	-	-	-	1,012	13,565
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													11,410
Total Proved + Probable Reserves													
Porosity, %	8.4	0.5	7.4	0.5	7.8	0.6	10.2	0.6	-	-	8.8	0.5	
Oil-Down-To, m ss	-408	-408	-408	-408	-408	-408	-408	-408	-	-	-376	-376	
Gross Rock Volume, 1000 ac-ft	421	421	386	386	476	476	342	342	-	-	805	805	
Area, acres	7,421	7,421	6,909	6,909	6,397	6,397	5,405	5,405	-	-	3,649	3,649	
Oil Initially-in-Place, Mbbl	12,624	5,718	55,483	7,868	49,805	18,461	125,149	13,250	-	-	201,571	25,308	515,237
Recovery Factor, %	-	5.0	2.5	35.0	2.5	35.0	2.5	35.0	-	-	2.0	10.0	5.1
Original Recoverable, Mbbl	-	286	1,387	2,754	1,245	6,461	3,129	4,638	-	-	4,031	2,531	26,462
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													24,307
Total Proved + Probable + Possible Reserves													
Porosity, %	8.9	0.6	7.7	0.6	8.2	0.7	10.7	0.7	-	-	9.2	0.6	
% 2P Gross Rock Volume, %	102.5%	102.5%	102.5%	102.5%	102.5%	102.5%	102.5%	102.5%	-	-	105%	105%	
Gross Rock Volume, 1000 ac-ft	432	432	396	396	488	488	350	350	-	-	845	845	
Area, acres	7,421	7,421	6,909	6,909	6,397	6,397	5,405	5,405	-	-	3,649	3,649	
Oil Initially-in-Place, Mbbl	13,587	7,033	59,714	9,678	53,603	22,076	134,691	15,845	-	-	222,232	31,888	570,346
Recovery Factor, %	-	10.0	3.5	40.0	3.5	40.0	3.5	40.0	-	-	2.5	15.0	6.8
Original Recoverable, Mbbl	-	703	2,090	3,871	1,876	8,830	4,714	6,338	-	-	5,556	4,783	38,762
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													36,607

ShaMaran Petroleum Corp.
Reservoir and Fluid Properties
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Age Zone	Jurassic CGTB (1)	Jurassic Upper (2) Medium Oil	Jurassic Upper (2) Heavy Oil	Jurassic Alan	Jurassic Mus
Lithology	Shale, Anhydrite with LST layers	Fractured LST & DOL	Fractured LST & DOL	Anhydrite & DOL	Fractured LST & DOL
Field Units (3)(4)(5)					
Reservoir Properties					
Top Structure Depth, ft SS	853	738	738	16	-427
Max Net Oil Pay Thickness, ft	8	361	361	115	243
Mapped Pool Area, ac	2,755	8,036	8,036	7,801	3,866
Well Test Oil-Down-To, ft SS	318	-1,339	-1,339	-1,509	-1,235
Well Test Water-Up-To, ft SS	n/a	n/a	n/a	n/a	-1,635
Estimated OWC Depth, m SS	-1,473	-1,473	-1,473	-1,903	-1,435
Matrix Permeability (AT-1 & -2 Core), mD	0.1 - 1	0.1 - 1	0.1 - 1	n/a	1 - 50
Initial Reservoir Pressure (at -232.5 m SS), psia	1,410	1,410	1,410	1,410	1,410
Reservoir Temperature, F	110	110	110	110	110
Fluid Properties					
Stock Tank Oil Gravity, degrees API	26	20.0	13.5	21	13 - 23
Oil Viscosity (insitu), cp	n/a	6	478	45	33 - ?
Solution GOR, scf/bbl	n/a	330	n/a	189	139 - 200
Bubble Point Pressure, psia	n/a	923	n/a	735	847
Flashed Gas H2S Content, mol %	n/a	24	n/a	20	10
Flashed Gas CO2 Content, mol %	n/a	7	n/a	19	5
Metric Units (3)(4)(5)					
Reservoir Properties					
Top Structure Depth, m SS	260	225	225	5	-130
Max. Net Oil Pay Thickness, m	2.4	110	110	35	74
Mapped Pool Area, km^2	11.1	33	33	31.6	15.6
Well Test Oil-Down-To, m SS	97	-408	-408	-460	-376
Well Test Water-Up-To, m SS	n/a	n/a	n/a	n/a	-498
Estimated OWC Depth, m SS	-449	-449	-449	-580.1	-437
Matrix Permeability (AT-1 & -2 Core), mD	0.1 - 1	0.1 - 1	0.1 - 1	n/a	1 - 50
Initial Reservoir Pressure (at -232.5 m SS), kPa	9,722	9,722	9,722	9,722	9,722
Reservoir Temperature, C	43	43	43	43	43
Fluid Properties					
Stock Tank Oil Density, g/cc	0.898	0.934	0.976	0.928	0.916 - 0.979
Oil Viscosity (insitu), mPa.s	n/a	6	478	45	33 - ?
Solution GOR, m^3/m^3	n/a	59	n/a	34	25 - 36
Bubble Point Pressure, kPa	n/a	6364	n/a	5,068	5,840
Flashed Gas H2S Content, mol %	n/a	24	n/a	20	10
Flashed Gas CO2 Content, mol %	n/a	7	n/a	19	5

(1) CGTB: Chia Gara Transition Beds
(2) Upper Jurassic: Barsarin, Naokelekan, U & L Sargelu
(3) Fluid properties are still uncertain and vary with depth within the same zone. The quoted values relate to the sampling depth and may not represent an average for the zone
(4) Depths below subsea are negative
(5) "n/a" designates the data was not available

ShaMaran Petroleum Corp.
Summary of Economic Parameters
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Price Schedule

McDaniel & Associates January 1, 2022 Forecast Price Case
Crude oil sales price based on current marketing agreement.
See

Operating Costs (2022$ - US)

	2022	2023	2024	2025	2026	2027
G&A $M/yr	$17,510	$17,510	$17,510	$17,510	$14,884	$14,884
Power $M/yr	-	-	-	-	-	-
Heavy EWT $M/yr	-	-	-	-	-	-
Fixed $M/yr	$27,190	$27,190	$27,190	$27,190	$27,190	$27,190
Variable, $/wm	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000
Variable, $/bbl	2.63	2.63	2.63	2.63	2.63	2.63

* G&A costs are reduced by 15% in 2026 following drilling campaign
* Fixed costs are reduced by 20% once the EPF is no longer required
* Fixed costs were reduced by 10 percent per year in each of the last three years of the forecast
* PDP costs were based on the G&A costs 20% reduction in 2023 as there is no drilling campaign and fixed reduction of 25% for removal of EPF in 2023

Capital Costs (2022$ - US)

See Table 12

US$ million	Year	Description
55.4	2022-2023	Total Facilities & Other Costs for PDP Case
89.1	2022-2023	Total Facilities & Other Costs for 1P Case
89.1	2022-2023	Total Facilities & Other Costs for 2P/3P Cases
13.0		Avg. Drill, Complete, Test and Tie-in 1P/2P/3P Cases

Abandonment Costs (2022$ - US)

New Well Abandonments	$1,000,000	/ well - Allocated to each of the last 10 years of each forecast
Existing Abandonment Liability	$57.519	million - Allocated to each of the last 10 years of each forecast

Fiscal Terms

ShaMaran Working Interest for Costs (after historical cost recovery)	27.6%
ShaMaran Working Interest for Revenues	27.6%
State Crude Oil/Natural Gas Royalty	10%
Cost Oil Recovery Limit	40%
Cost Gas Recovery Limit	55%
Total Exploration Cost Oil Recovery Balance at December 31, 2021	-
ShaMaran - Preferential Initial Lifting Balance at December 31, 2021	-
TAQA Rebalancing Payment Due to ShaMaran at December 31, 2021	-
TAQA - Preferential Initial Lifting Balance at December 31, 2021	-
Total Development Cost Oil Recovery Balance at December 31, 2021	$ 672 million
ShaMaran Share of Total Cost Oil Recovery Balance	$ 185 million
ShaMaran Share of Government Carry at December 31, 2021	$ 8.8 million
Contractor Share of Profit Oil	Based on R-Factor = Cumulative Revenues / Cumulative Costs
R < 1.0	32%
1 < R < 2.25	32% - (32-16)*(R-1)/(2.25-1)
R > 2.25	16%
Contractor Share of Profit Gas	Based on R-Factor = Cumulative Revenues / Cumulative Costs
R < 1.0	40%
1 < R < 2.75	40% - (40-22)*(R-1)/(2.75-1)
R > 2.75	22%
Capacity Building Value Bonus	30% of ShaMaran's profit oil/profit gas
Income Tax	Not applicable (40% tax is paid out of government profit oil share)
Contract Expiry	1-Oct-2033 (Contract renewal assumed for 3P reserves)

ShaMaran Petroleum Corp.
Forecast of Capital Costs - 2022$
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Proved Developed Producing Reserves

Year	Production Wells #	Production Wells 2022 US$M	Injection Wells #	Injection Wells 2022 US$M	Recompletions #	Recompletions 2022 US$M	Facilities 2022 US$M	Capitalized Opex & Maint. 2022 US$M	Total Area 2022 US$M	Total Area Future US$M
2022	-	-	-	-	-	-	55,422	-	55,422	55,422
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**-**	**55,422**	**-**	**55,422**	**55,422**

Total Proved Reserves

Year	Production Wells #	Production Wells 2022 US$M	Injection Wells #	Injection Wells 2022 US$M	Recompletions #	Recompletions 2022 US$M	Facilities 2022 US$M	Capitalized Opex & Maint. 2022 US$M	Total Area 2022 US$M	Total Area Future US$M
2022	1	13,000	-	-	-	-	89,131	-	102,131	102,131
2023	2	26,000	-	-	-	-	-	-	26,000	26,520
2024	2	26,000	-	-	-	-	-	-	26,000	27,050
2025	1	13,000	-	-	-	-	-	-	13,000	13,796
2026	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**6.0**	**78,000**	**-**	**-**	**-**	**-**	**89,131**	**-**	**167,131**	**169,497**

ShaMaran Petroleum Corp.
Forecast of Capital Costs - 2022$
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Total Proved + Probable Reserves

Year	Production Wells #	Production Wells 2022 US$M	Injection Wells #	Injection Wells 2022 US$M	Recompletions #	Recompletions 2022 US$M	Facilities 2022 US$M	Capitalized Opex & Maint. 2022 US$M	Total Area 2022 US$M	Total Area Future US$M
2022	1	13,000	-	-	-	-	89,131	-	102,131	102,131
2023	2	26,000	-	-	-	-	-	-	26,000	26,520
2024	2	26,000	-	-	-	-	-	-	26,000	27,050
2025	1	13,000	-	-	-	-	-	-	13,000	13,796
2026	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**6.0**	**78,000**	**-**	**-**	**-**	**-**	**89,131**	**-**	**167,131**	**169,497**

Total Proved + Probable + Possible Reserves

Year	Production Wells #	Production Wells 2022 US$M	Injection Wells #	Injection Wells 2022 US$M	Recompletions #	Recompletions 2022 US$M	Facilities 2022 US$M	Capitalized Opex & Maint. 2022 US$M	Total Area 2022 US$M	Total Area Future US$M
2022	1	13,000	-	-	-	-	89,131	-	102,131	102,131
2023	2	26,000	-	-	-	-	-	-	26,000	26,520
2024	2	26,000	-	-	-	-	-	-	26,000	27,050
2025	1	13,000	-	-	-	-	-	-	13,000	13,796
2026	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	**6.0**	**78,000**	**-**	**-**	**-**	**-**	**89,131**	**-**	**167,131**	**169,497**

Currency: USD

ShaMaran Petroleum Corp.
Summary of Contingent Resources Estimates
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Note: Contingent resources were estimated incrementally by subtracting the reserves (Table 6) from the total recoverable resources (Tables 14 to 16)

Light/Medium Oil (5)

			Contingent Resources (1)(2)(3)		
			1C	2C	3C
Field	Zone	Sub-Class	Mbbl	Mbbl	Mbbl
Total	Property Gross	On Hold	4,671	5,851	7,105
	Company Gross (4)	On Hold	1,289	1,615	1,961

Heavy Oil (5)

			Contingent Resources (1)(2)(3)		
			1C	2C	3C
Field	Zone		Mbbl	Mbbl	Mbbl
Total	Property Gross	On Hold	13,918	23,040	88,827
	Company Gross (4)	On Hold	3,841	6,359	24,516
	Property Gross	Not Viable	46,463	97,152	121,544
	Company Gross (4)	Not Viable	12,824	26,814	33,546

Natural Gas

			Contingent Resources (1)(2)(3)		
			1C	2C	3C
Field	Zone		MMcf	MMcf	MMcf
Total	Property Gross	Not Viable	-	-	-
	Company Gross (4)	Not Viable	-	-	-

(1) There is no certainty that it will be economically viable to produce any portion of the resources.

(2) The numbers presented above have not been risked for the chance of development. The chance of development is defined as the probability of a project being commercially v Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, soc license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. The chance of development was estimated to be 70 percent for the Light/Medium and Heavy Oil for On Hold and 10 percent for the Heavy Oil that classified as Not Viable. For the Heavy Oil Not Viable, there are currently no plans to further appraise the extended heavy oil development.

(3) Contingent resources were estimated by subtracting the reserves from the total recoverable resources. For the Heavy Oil, the volumes sub-classified as On Hold were based on the total resources for the next potential development including the East Flank. The volumes sub-classified as Not Viable were based on the total discovered resources less the total resources classified as On Hold and those classified as reserves.

(4) Company gross resources based on ShaMaran's 27.6 percent working interest share of the property gross resources.

(5) Fluid type is classifed according to COGEH: Light/Medium Oil is based on density less than 920 kg/m3 and Heavy Oil is between 920 and 1000 kg/m3. Hence the resources presented in Table 14 are considered Light/Medium Oil and in Tables 15 and 16 Heavy Oil.

Prices: McDaniel January 1, 2022
Eff. Date: December 31, 2021
Currency: USD

Table 14

ShaMaran Petroleum Corp.
Crude Oil Reserves & Contingent Resources Summary - Medium Oil
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

	Barsarin		Naokelekan		Upper Sargelu		Lower Sargelu		Alan		Mus		Total
Zone	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Field**
Unchanged Parameters													
Water Saturation, %	25.0	10.0	15.0	10.0	25.0	10.0	25.0	10.0	20.0	10.0	25.0	10.0	
Oil Shrinkage, frac	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	
Net to Gross Ratio, frac	0.07	0.47	0.33	0.56	0.24	1.00	0.68	1.00	0.12	0.29	0.53	1.00	
Proved Developed Producing Reserves (PDP)													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1,000 ac-ft	1,077	1,077	773	773	1,139	1,139	382	382	630.0	630	460	460	
Oil Initially-in-Place, Mbbl	24,686	10,379	88,553	9,400	100,469	32,666	122,801	11,405	31,543	4,361	103,009	10,990	550,261
Recovery Factor, %	5.0	60.0	10.5	70.0	10.5	70.0	10.5	70.0	1.0	15.0	2.5	40.0	15.6
Original Recoverable, Mbbl	1,234	6,227	9,298	6,580	10,549	22,866	12,894	7,983	315	654	2,575	4,396	85,574
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													33,865
Low Estimate Total Discovered Resources (1P+1C)													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1,000 ac-ft	1,077	1,077	773	773	1,139	1,139	382	382	630.0	630	460	460	
Oil Initially-in-Place, Mbbl	28,751	12,088	100,453	10,340	100,389	34,000	124,634	11,405	31,543	4,361	101,102	10,990	570,054
Recovery Factor, %	7.5	62.5	12.5	75.0	12.5	75.0	12.5	75.0	1.0	15.0	6.0	75.0	18.9
Original Recoverable, Mbbl	2,156	7,555	12,557	7,755	12,549	25,500	15,579	8,554	315	654	6,066	8,243	107,483
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													55,774
Best Estimate Total Discovered Resources (2P+2C)													
Porosity, %	8.4	0.5	7.4	0.5	7.8	0.6	10.2	0.6	8.3	0.5	8.8	0.5	
Gross Rock Volume, 1,000 ac-ft	1,151	1,151	816	816	1,193	1,193	392	392	634.7	635	460	460	
Oil Initially-in-Place, Mbbl	32,321	16,137	111,551	13,635	110,679	42,733	134,647	14,046	33,454	5,492	106,423	13,738	634,857
Recovery Factor, %	10.0	65.0	14.0	80.0	14.0	80.0	14.0	80.0	2.0	20.0	10.0	80.0	22.6
Original Recoverable, Mbbl	3,232	10,489	15,617	10,908	15,495	34,187	18,851	11,237	669	1,098	10,642	10,990	143,416
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													91,707
High Estimate Total Discovered Resources (3P+3C)													
Porosity, %	8.9	0.6	7.7	0.6	8.2	0.7	10.7	0.7	8.7	0.6	9.2	0.6	
Gross Rock Volume, 1,000 ac-ft	1,224	1,224	859	859	1,247	1,247	402	402	639.5	639	460	460	
Oil Initially-in-Place, Mbbl	36,097	20,597	123,231	17,214	121,471	52,111	145,005	16,807	35,391	6,640	111,744	16,485	702,794
Recovery Factor, %	10.0	70.0	16.0	82.5	16.0	82.5	16.0	82.5	3.0	25.0	12.5	82.5	25.9
Original Recoverable, Mbbl	3,610	14,418	19,717	14,202	19,435	42,992	23,201	13,866	1,062	1,660	13,968	13,600	181,730
Cumulative Production, Mbbl													51,709
Remaining Recoverable, Mbbl													130,022

Prices: McDaniel January 1, 2022
Eff. Date: December 31, 2021
Currency: USD

Table 15

ShaMaran Petroleum Corp.
Crude Oil Reserves & Contingent Resources Summary - Heavy Oil - Including Additional Drilling Development
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

	Barsarin		Naokelekan		Upper Sargelu		Lower Sargelu		Alan		Mus		Total
Zone	Matrix	Fractures	Matrix	Fractures	Matrix	Fractures	Matrix	Fractures	Matrix	Fractures	Matrix	Fractures	Field
Unchanged Parameters													
Water Saturation, %	25.0	10.0	15.0	10.0	25.0	10.0	25.0	10.0	25.0	10.0	25.0	10.0	
Oil Shrinkage, frac	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.91	0.91	0.91	0.91	
Net to Gross Ratio, frac	0.07	0.47	0.33	0.56	0.24	1.00	0.68	1.00	0.12	0.29	0.53	1.00	
Proved Developed Producing Reserves (PDP)													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	-	-	8.3	0.4	
Gross Rock Volume, 1,000 ac-ft	421	421	386	386	476	476	342	342	-	-	805	805	
Oil Initially-in-Place, Mbbl	11,993	4,574	52,709	6,294	47,315	15,384	118,891	11,042	-	-	191,492	20,246	479,941
Recovery Factor, %	-	-	1.0	25.0	1.0	25.0	1.0	25.0	-	-	-	-	2.2
Original Recoverable, Mbbl	-	-	527	1,574	473	3,846	1,189	2,760	-	-	-	-	10,369
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													8,215
Low Estimate Total Discovered Resources (1P+1C)													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1,000 ac-ft	920	920	710	710	952	952	480	480	157	157	828	828	
Oil Initially-in-Place, Mbbl	26,582	11,176	99,902	10,283	90,844	30,768	169,589	15,519	7,826	1,154	193,512	21,035	678,190
Recovery Factor, %	-	15.0	1.0	30.0	1.0	30.0	1.0	30.0	-	5.0	0.5	20.0	4.1
Original Recoverable, Mbbl	-	1,676	999	3,085	908	9,230	1,696	4,656	-	58	968	4,207	27,483
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													25,328
Best Estimate Total Discovered Resources (2P+2C)													
Porosity, %	8.4	0.5	7.4	0.5	7.8	0.6	10.2	0.6	8.3	0.5	8.8	0.5	
Gross Rock Volume, 1,000 ac-ft	1,028	1,028	791	791	1,097	1,097	520	520	199	199	846	846	
Oil Initially-in-Place, Mbbl	31,274	15,615	117,174	14,322	110,225	42,558	193,440	20,179	10,482	1,836	208,061	26,858	792,023
Recovery Factor, %	-	20.0	2.5	35.0	2.5	35.0	2.5	35.0	-	5.0	1.0	25.0	6.3
Original Recoverable, Mbbl	-	3,123	2,929	5,013	2,756	14,895	4,836	7,063	-	92	2,081	6,714	49,501
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													47,347
High Estimate Total Discovered Resources (3P+3C)													
Porosity, %	8.9	0.6	7.7	0.6	8.2	0.7	10.7	0.7	8.7	0.6	9.2	0.6	
Gross Rock Volume, 1,000 ac-ft	1,363	1,363	1,044	1,044	1,545	1,545	649	649	328	328	940	940	
Oil Initially-in-Place, Mbbl	43,546	24,848	162,378	22,683	162,980	69,919	253,461	29,378	18,078	3,618	242,598	35,789	1,069,276
Recovery Factor, %		30.0	3.5	60.0	3.5	60.0	3.5	60.0	-	10.0	2.0	60.0	11.9
Original Recoverable, Mbbl	-	7,454	5,683	13,610	5,704	41,951	8,871	17,627	-	362	4,852	21,474	127,588
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													125,434

Prices: McDaniel January 1, 2022
Eff. Date: December 31, 2021
Currency: USD

Table 16

ShaMaran Petroleum Corp.
Crude Oil Reserves & Contingent Resources Summary - Heavy Oil - Included All Development Phases
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

	Barsarin		Naokelekan		Upper Sargelu		Lower Sargelu		Alan		Mus		Total
Zone	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Matrix**	**Fractures**	**Field**
Unchanged Parameters													
Water Saturation, %	25.0	10.0	15.0	10.0	25.0	10.0	25.0	10.0	25.0	10.0	25.0	10.0	
Oil Shrinkage, frac	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.91	0.91	0.91	0.91	
Net to Gross Ratio, frac	0.07	0.47	0.33	0.56	0.24	1.00	0.68	1.00	0.12	0.29	0.53	1.00	
Proved Developed Producing Reserves (PDP)													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1,000 ac-ft	421	421	386	386	476	476	342	342	-	-	805	805	
Oil Initially-in-Place, Mbbl	11,993	4,574	52,709	6,294	47,315	15,384	118,891	11,042	-	-	191,492	20,246	479,941
Recovery Factor, %	-	-	1.0	25.0	1.0	25.0	1.0	25.0	-	-	-	-	2.2
Original Recoverable, Mbbl	-	-	527	1,574	473	3,846	1,189	2,760	-	-	-	-	10,369
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													8,215
Low Estimate Total Discovered Resources (1P+1C)													
Porosity, %	8.0	0.4	7.0	0.4	7.4	0.5	9.6	0.5	7.9	0.4	8.3	0.4	
Gross Rock Volume, 1,000 ac-ft	920	920	710	710	952	952	480	480	157	157	828	828	
Oil Initially-in-Place, Mbbl	26,582	11,176	99,902	10,283	90,844	30,768	169,589	15,519	7,826	1,154	193,512	21,035	678,190
Recovery Factor, %	-	40.0	5.0	60.0	5.0	60.0	5.0	60.0	-	5.0	2.5	60.0	10.9
Original Recoverable, Mbbl	-	4,471	4,995	6,170	4,542	18,461	8,479	9,311	-	58	4,838	12,621	73,946
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													71,791
Best Estimate Total Discovered Resources (2P+2C)													
Porosity, %	8.4	0.5	7.4	0.5	7.8	0.6	10.2	0.6	8.3	0.5	8.8	0.5	
Gross Rock Volume, 1,000 ac-ft	1,028	1,028	791	791	1,097	1,097	520	520	199	199	846	846	
Oil Initially-in-Place, Mbbl	31,274	15,615	117,174	14,322	110,225	42,558	193,440	20,179	10,482	1,836	208,061	26,858	792,023
Recovery Factor, %	-	70.0	10.0	70.0	10.0	70.0	10.0	70.0	-	5.0	10.0	70.0	18.5
Original Recoverable, Mbbl	-	10,930	11,717	10,026	11,023	29,791	19,344	14,125	-	92	20,806	18,800	146,654
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													144,499
High Estimate Total Discovered Resources (3P+3C)													
Porosity, %	8.9	0.6	7.7	0.6	8.2	0.7	10.7	0.7	8.7	0.6	9.2	0.6	
Gross Rock Volume, 1,000 ac-ft	1,363	1,363	1,044	1,044	1,545	1,545	649	649	328	328	940	940	
Oil Initially-in-Place, Mbbl	43,546	24,848	162,378	22,683	162,980	69,919	253,461	29,378	18,078	3,618	242,598	35,789	1,069,276
Recovery Factor, %		80.0	12.5	80.0	12.5	80.0	12.5	80.0	-	10.0	12.5	80.0	23.3
Original Recoverable, Mbbl	-	19,878	20,297	18,146	20,373	55,935	31,683	23,503	-	362	30,325	28,632	249,133
Cumulative Production, Mbbl													2,155
Remaining Recoverable, Mbbl													246,978

Currency: USD

ShaMaran Petroleum Corp.
Summary of Discovered Petroleum Initially-In-Place Estimates
Forecast Prices and Costs as of December 31, 2021

Atrush Field - Kurdistan Region

Reserves and Contingent Resources - Property Gross Values

		Crude Oil - Total PIIP [1]			Crude Oil	Crude Oil - Technical Reserves [2]				Crude Oil - Contingent Resources [3][4]		
		Low	Best	High	Cum. Prod.	PDP	1P	2P	3P	1C	2C	3C
Field	**Zone**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**	**Mbbl**
Medium Oil												
	Barsarin	40,839	48,458	56,695								
	Naokelekan	110,792	125,186	140,445								
	Upper Sargelu	134,389	153,413	173,582								
	Lower Sargelu	136,039	148,693	161,812								
	Alan	35,903	38,946	42,031								
	Mus	112,092	120,160	128,229								
Atrush	**Total**	**570,054**	**634,857**	**702,794**	**51,709**	**33,865**	**51,103**	**85,856**	**122,917**	**4,671**	**5,851**	**7,105**
Heavy Oil												
	Barsarin	37,759	46,889	68,394								
	Naokelekan	110,185	131,496	185,061								
	Upper Sargelu	121,612	152,783	232,899								
	Lower Sargelu	185,108	213,619	282,839								
	Alan	8,980	12,318	21,696								
	Mus	214,547	234,918	278,387								
Atrush	**Total**	**678,190**	**792,023**	**1,069,276**	**2,155**	**8,215**	**11,410**	**24,307**	**36,607**	**60,381**	**120,192**	**210,371**
Very Heavy Oil												
	Barsarin	-	-	-			-	-	-	-	-	-
	Naokelekan	-	-	-			-	-	-	-	-	-
	Upper Sargelu	-	-	-			-	-	-	-	-	-
	Lower Sargelu	-	-	-			-	-	-	-	-	-
	Alan	48,100	130,274	231,491			-	-	-	-	-	-
	Mus	-	-	-			-	-	-	-	-	-
Atrush	**Total**	**48,100**	**130,274**	**231,491**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total												
	Barsarin	78,597	95,347	125,089			-	-	-	-	-	-
	Naokelekan	220,977	256,682	325,506			-	-	-	-	-	-
	Upper Sargelu	256,001	306,196	406,481			-	-	-	-	-	-
	Lower Sargelu	321,147	362,312	444,651			-	-	-	-	-	-
	Alan	92,984	181,539	295,218			-	-	-	-	-	-
	Mus	326,639	355,079	406,616			-	-	-	-	-	-
Grand Total		**1,296,344**	**1,557,155**	**2,003,561**	**53,863**	**42,079**	**62,513**	**110,163**	**159,524**	**65,051**	**126,043**	**217,475**

(1) There is no certainty that it will be economically viable or technically feasible to produce any portion of the DPIIP.
(2) Reserves are based on the current Atrush field development. These are technical reserves prior to economic or license cut-offs.
(3) There is no certainty that it will be economically viable to produce any portion of the contingent resources.
(4) These are unrisked contingent resources that do not take into account the chance of development.

McDaniel & Associates Consultants Ltd.
Summary of Price Forecasts
January 1, 2022

Table 18

Year	Brent Crude Oil Price $US/bbl	Atrush Field Differential $US/bbl	Atrush Field Price $US/bbl	Inflation Forecast %
2022	75.00	15.78	59.22	2.00
2023	69.87	15.78	54.09	2.00
2024	67.63	15.78	51.85	2.00
2025	68.98	15.78	53.20	2.00
2026	70.36	15.78	54.58	2.00
2027	71.77	15.78	55.99	2.00
2028	73.20	15.78	57.42	2.00
2029	74.66	15.78	58.88	2.00
2030	76.16	15.78	60.38	2.00
2031	77.68	15.78	61.90	2.00
2032	79.23	15.78	63.45	2.00
2033	80.82	15.78	65.04	2.00
2034	82.44	15.78	66.66	2.00
2035	84.08	15.78	68.30	2.00
2036	85.77	15.78	69.99	2.00
2037	87.48	15.78	71.70	2.00
2038	89.23	15.78	73.45	2.00
2039	91.02	15.78	75.24	2.00
2040	92.84	15.78	77.06	2.00
2041	94.69	15.78	78.91	2.00
Thereafter	+2.0%	+2.0%	+2.0%	

Pricing Assumptions :
Brent price forecast based on the McDaniel & Associates January 1, 2022 Forecast Price Case
The differential is based on ShaMaran's current marketing agreement of $15.78/bbl including a trans
and quality differential.

Figure 1

Legend

■ City

International Border

ShaMaran Petroleum Corp

Property Location Map

Nov 15, 2021

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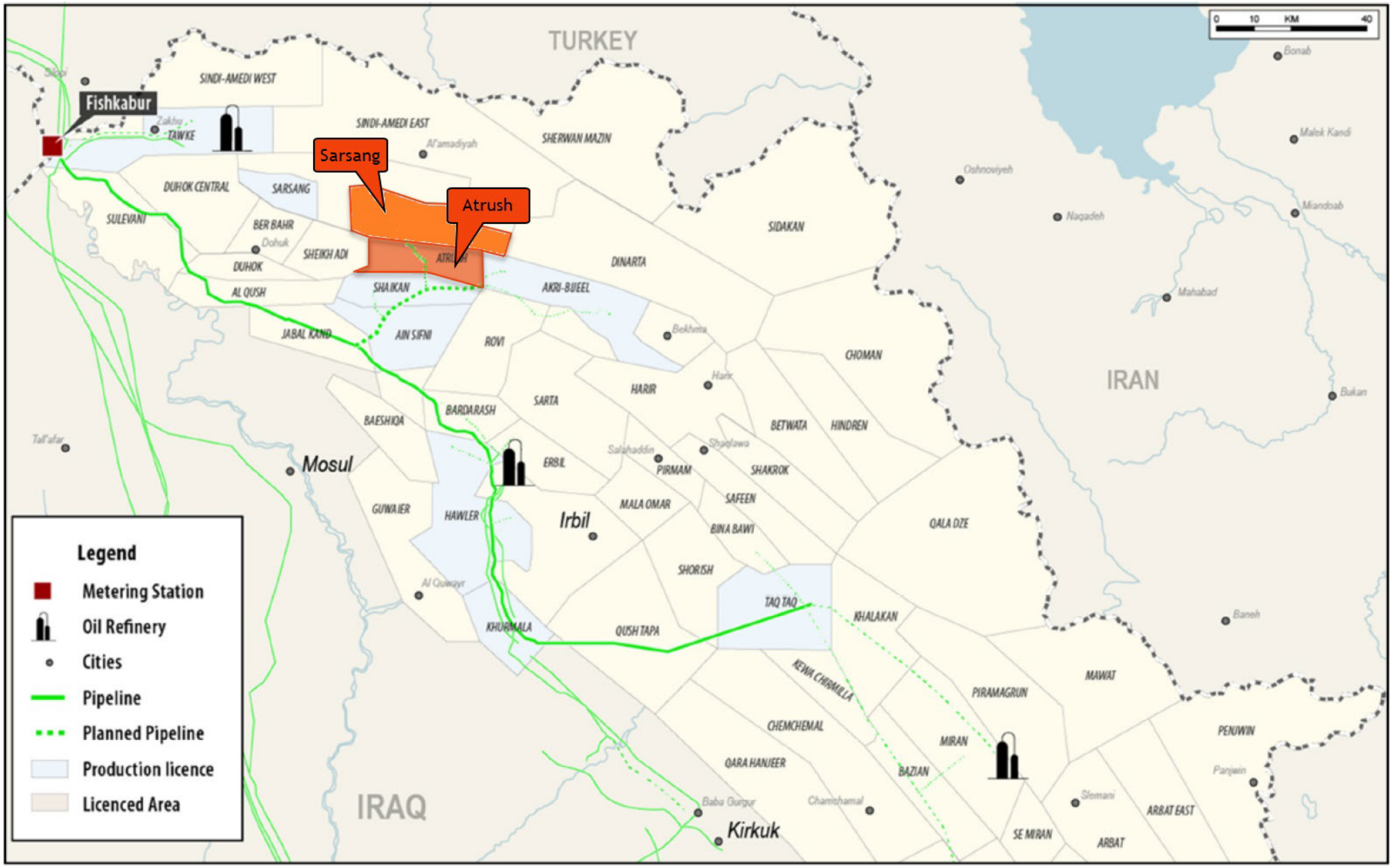
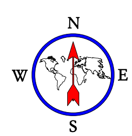
Figure 2





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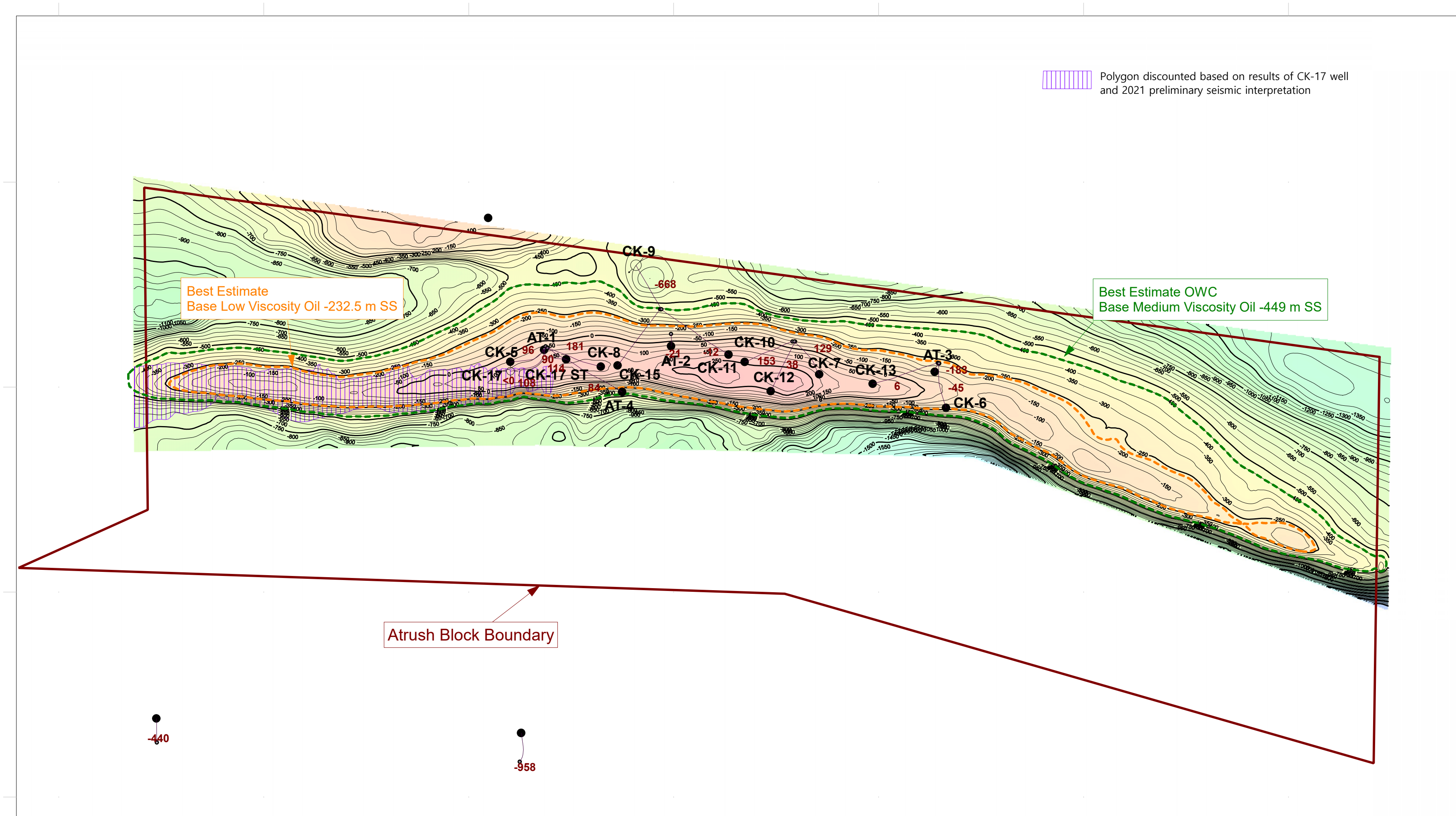
ShaMaran Petroleum Corp.
Atrush and Sarsang Blocks
Iraq - Kurdistan
Location Map

<AT>	Units – metres	November 15, 2021

Figure 3



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
Gas well	NT - Not Tested
Status unknown	NP - Not Present
Abandoned	NDE - Not Deep Enough
Water injector	LTG - Lowest Tested Gas
Drilling location	LTO - Lowest Tested Oil
	LKO - Lowest Known Oil

N W E S

5 0 5 10 km

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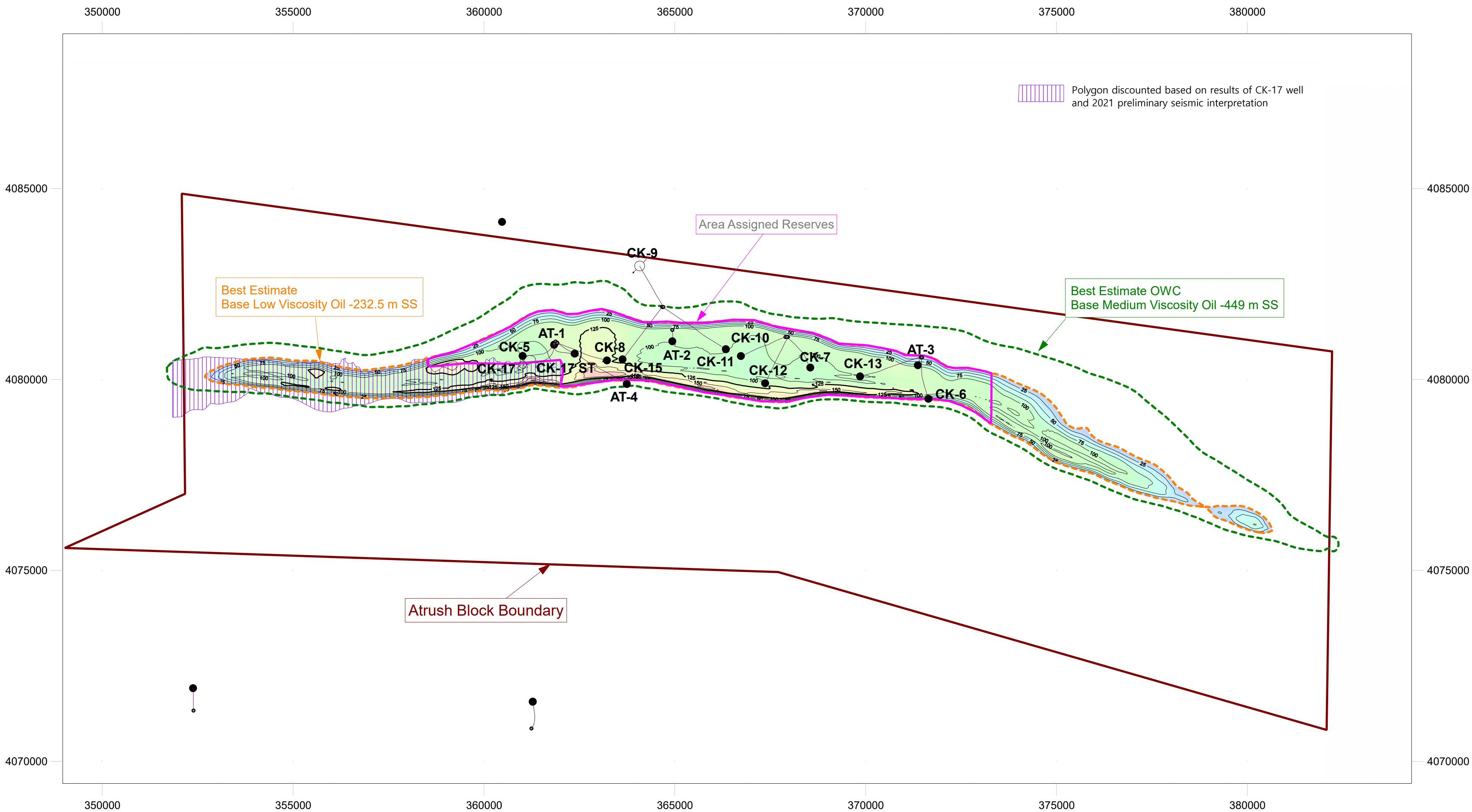
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Top Structure Map
Barsarin Formation
Based on 2019 TAQA Interpretation

<AT> | Units – metres | 15 November, 2021

Figure 4



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
Gas well	NT - Not Tested
Status unknown	NP - Not Present
Abandoned	NDE - Not Deep Enough
Water injector	LTG - Lowest Tested Gas
Drilling location	LTO - Lowest Tested Oil
	LKO - Lowest Known Oil

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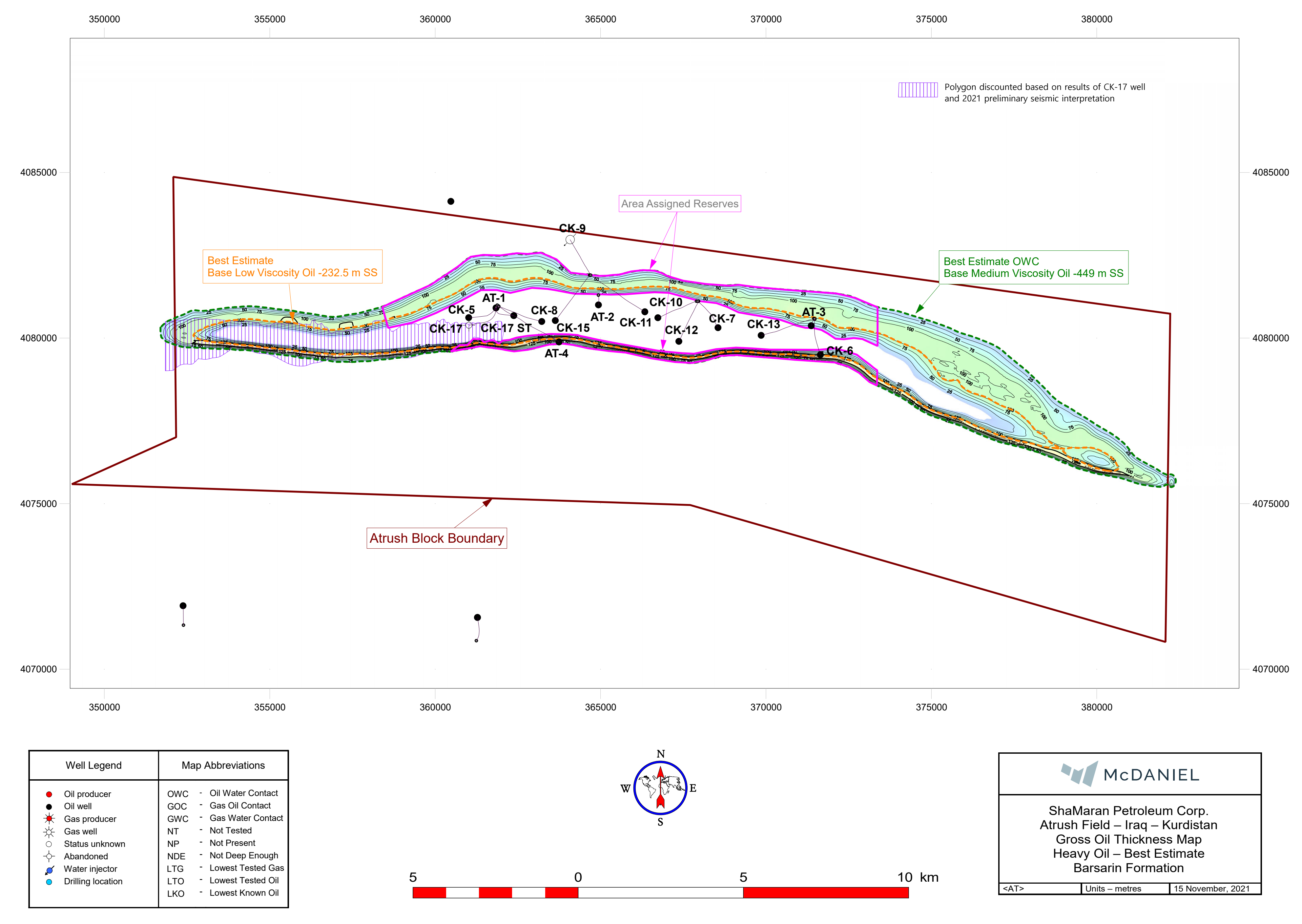
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Medium Oil – Best Estimate
Barsarin Formation

<AT>	Units – metres	15 November, 2021

Figure 5



Polygon discounted based on results of CK-17 well
and 2021 preliminary seismic interpretation
Area Assigned Reserves
Best Estimate
Base Low Viscosity Oil -232.5 m SS
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
Atrush Block Boundary
CK-9
AT-1
CK-5
CK-17
CK-17 ST
CK-8
CK-15
AT-2
AT-4
CK-10
CK-11
CK-12
CK-7
CK-13
AT-3
CK-6
350000
355000
360000
365000
370000
375000
380000
4085000
4080000
4075000
4070000
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
LTG - Lowest Tested Gas
LTO - Lowest Tested Oil
LKO - Lowest Known Oil
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10 km
McDANIEL
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Heavy Oil – Best Estimate
Barsarin Formation
<AT>
Units – metres
15 November, 2021

Figure 6

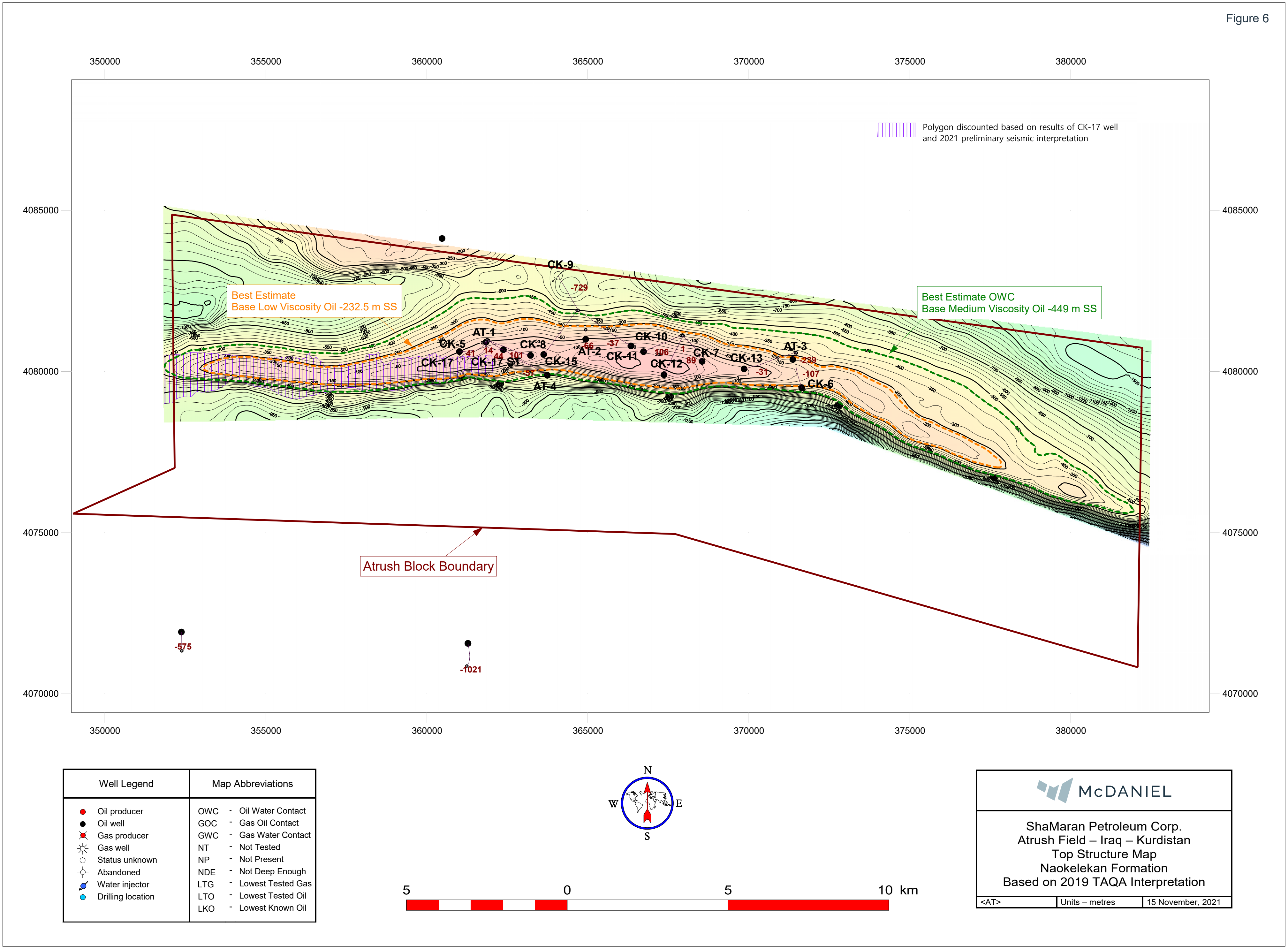
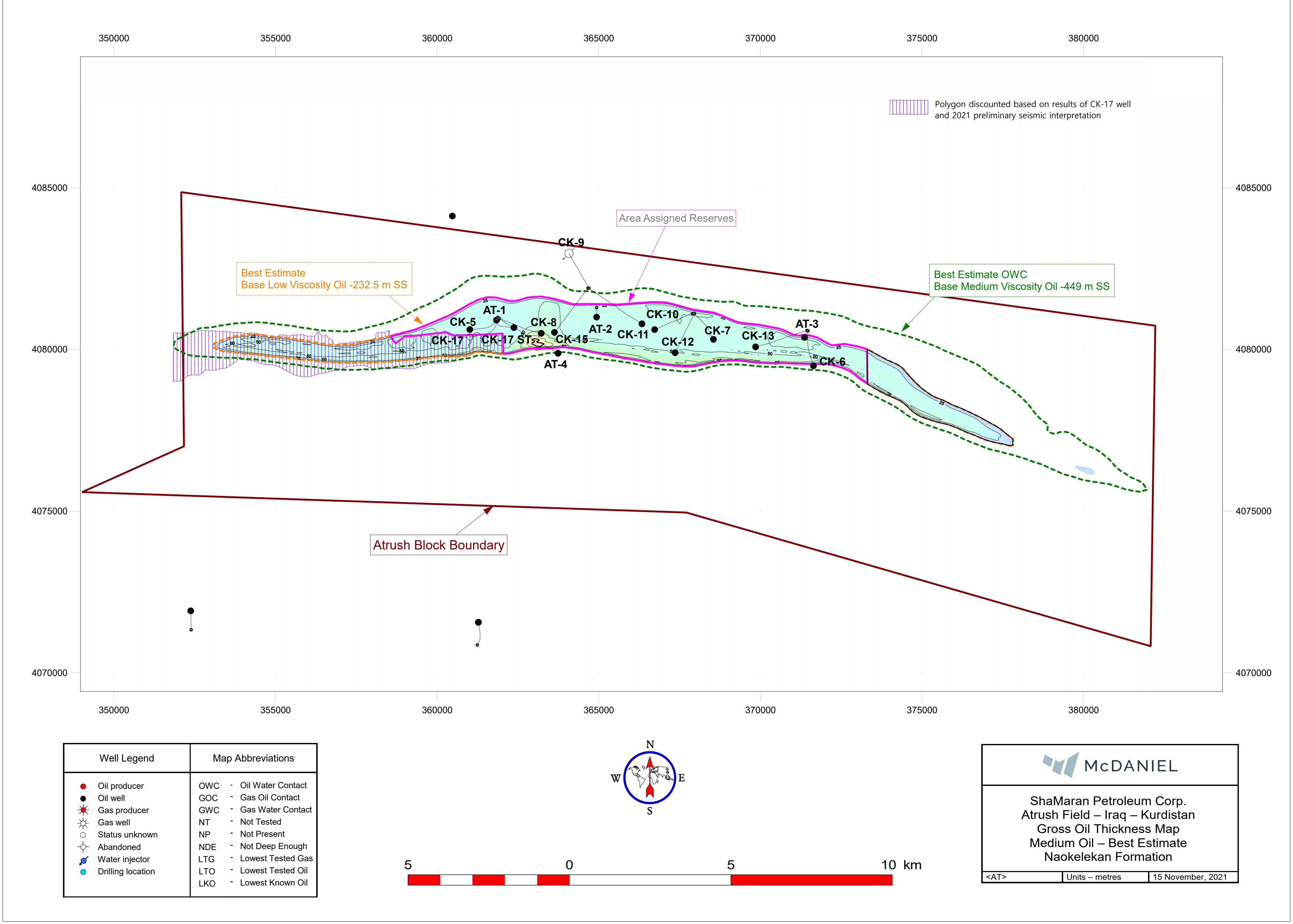

Polygon discounted based on results of CK-17 well and 2021 preliminary seismic interpretation
Best Estimate
Base Low Viscosity Oil -232.5 m SS
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
Atrush Block Boundary
CK-9
AT-1
CK-5
CK-8
CK-17
CK-17 ST
CK-15
AT-4
AT-2
CK-10
CK-11
CK-12
CK-7
CK-13
AT-3
CK-6
350000
355000
360000
365000
370000
375000
380000
4085000
4080000
4075000
4070000
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
LTG - Lowest Tested Gas
LTO - Lowest Tested Oil
LKO - Lowest Known Oil
5 0 5 10 km
McDANIEL
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Top Structure Map
Naokelekan Formation
Based on 2019 TAQA Interpretation
<AT>
Units – metres
15 November, 2021

Figure 7



Polygon discounted based on results of CK-17 well
and 2021 preliminary seismic interpretation
Area Assigned Reserves
Best Estimate
Base Low Viscosity Oil -232.5 m SS
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
Atrush Block Boundary
CK-9
AT-1
CK-5
CK-8
AT-2
CK-10
CK-11
CK-12
CK-7
CK-13
AT-3
CK-6
CK-17
CK-17 ST
CK-15
AT-4
350000
355000
360000
365000
370000
375000
380000
4085000
4080000
4075000
4070000
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
LTG - Lowest Tested Gas
LTO - Lowest Tested Oil
LKO - Lowest Known Oil
N
W
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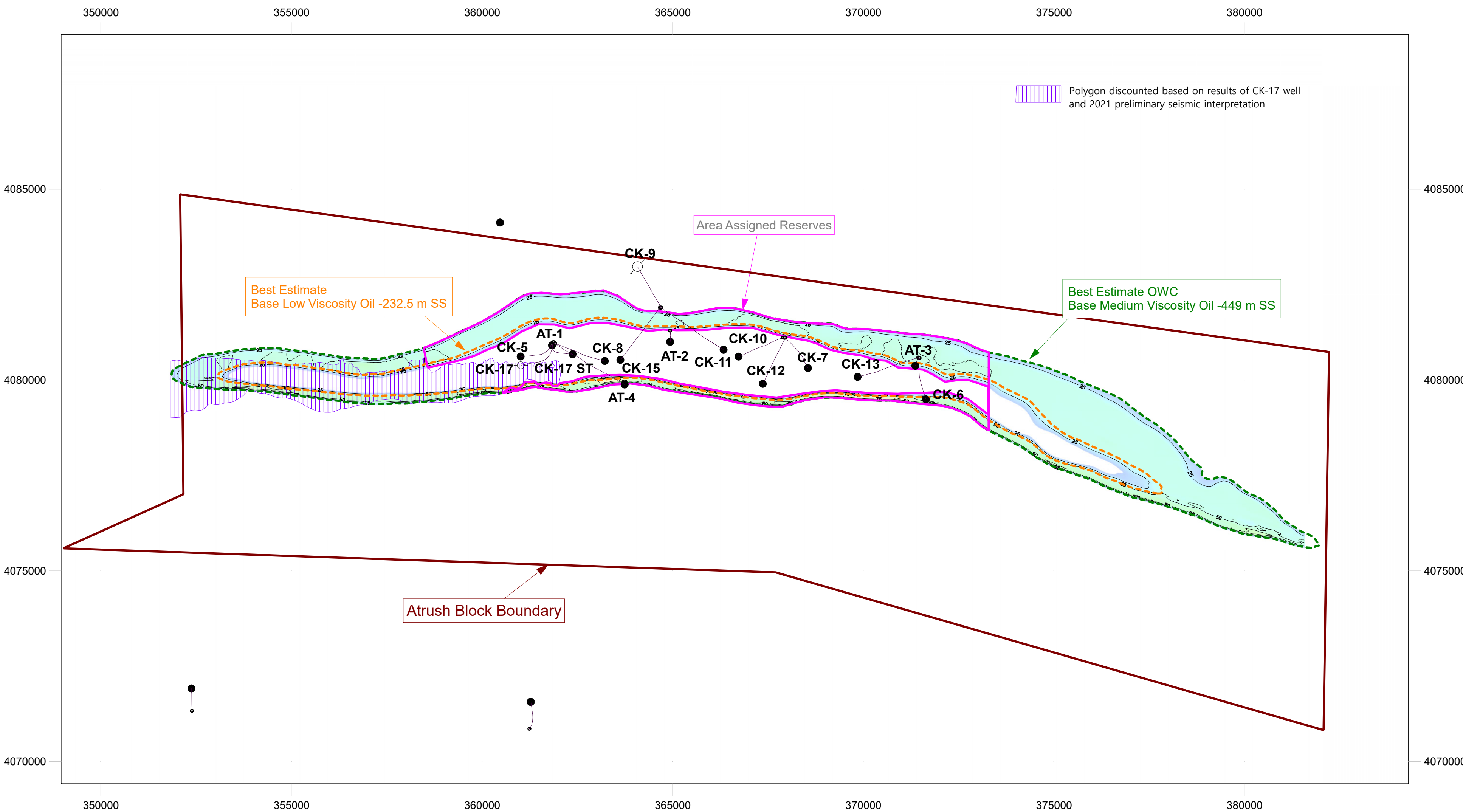
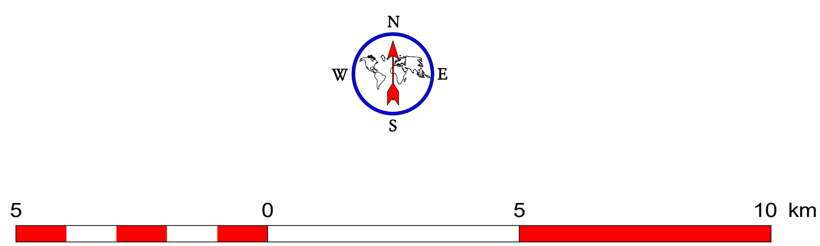
S
5
0
5
10 km
McDANIEL
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Medium Oil – Best Estimate
Naokelekan Formation
<AT>
Units – metres
15 November, 2021

Figure 8





Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
Gas well	NT - Not Tested
Status unknown	NP - Not Present
Abandoned	NDE - Not Deep Enough
Water injector	LTG - Lowest Tested Gas
Drilling location	LTO - Lowest Tested Oil
	LKO - Lowest Known Oil

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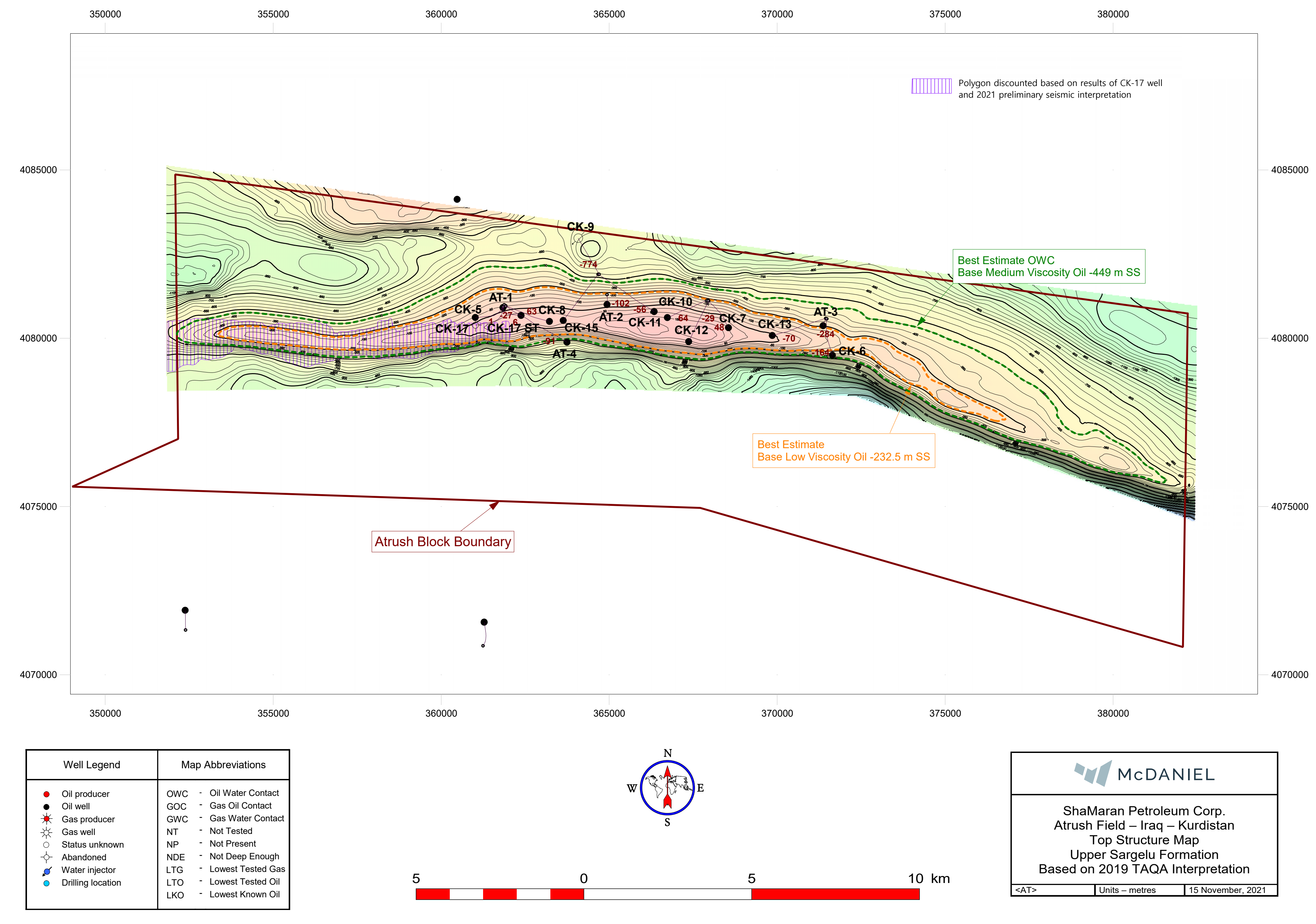
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Heavy Oil – Best Estimate
Naokelekan Formation

<AT>	Units – metres	15 November, 2021

Figure 9



Polygon discounted based on results of CK-17 well and 2021 preliminary seismic interpretation
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
Best Estimate
Base Low Viscosity Oil -232.5 m SS
Atrush Block Boundary
CK-9
AT-1
CK-5
CK-8
CK-17
CK-17 ST
CK-15
AT-4
AT-2
CK-11
GK-10
CK-12
CK-7
CK-13
AT-3
CK-6
350000
355000
360000
365000
370000
375000
380000
4085000
4080000
4075000
4070000
N
W
E
S
5
0
5
10 km
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
LTG - Lowest Tested Gas
LTO - Lowest Tested Oil
LKO - Lowest Known Oil
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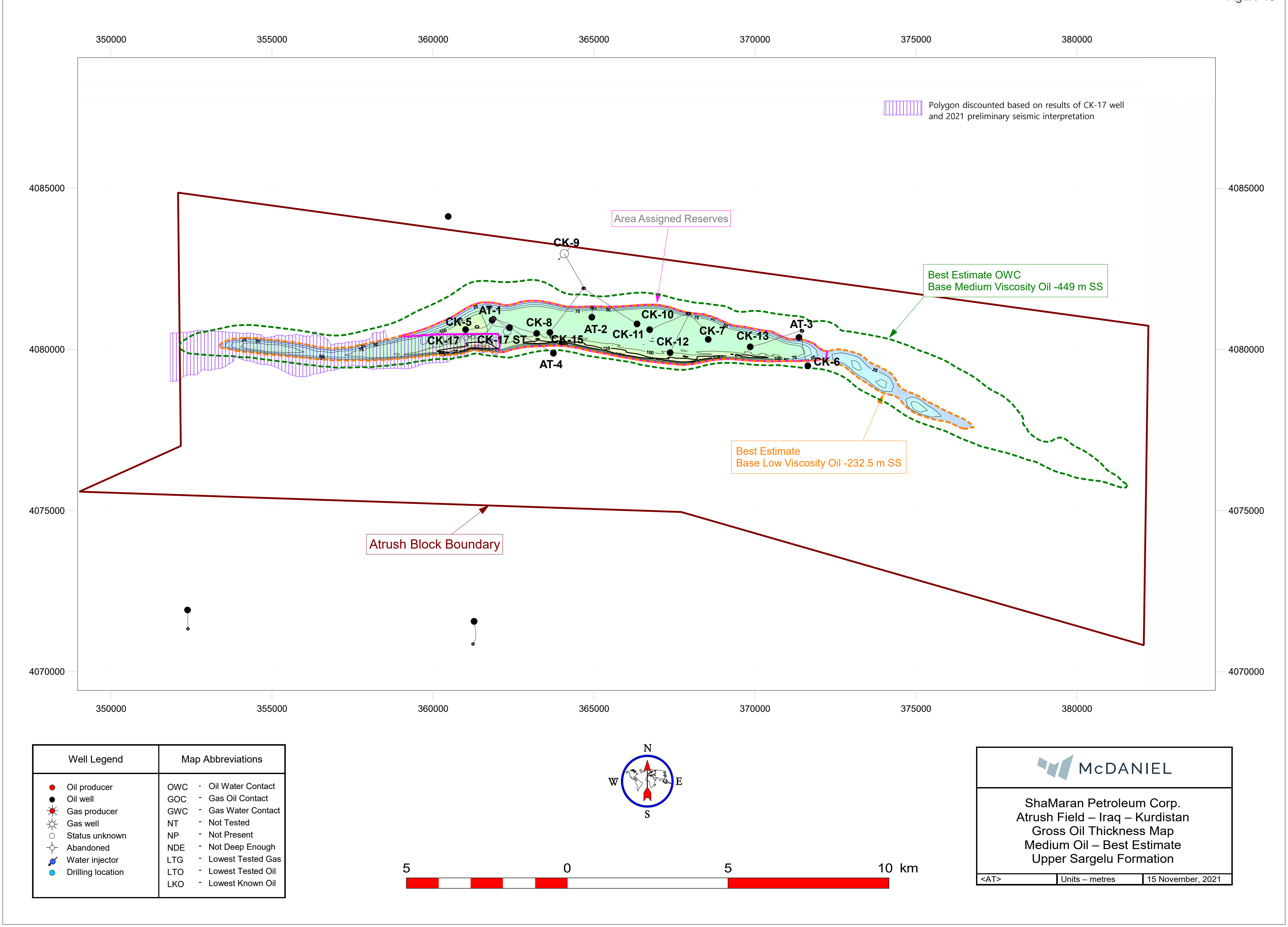
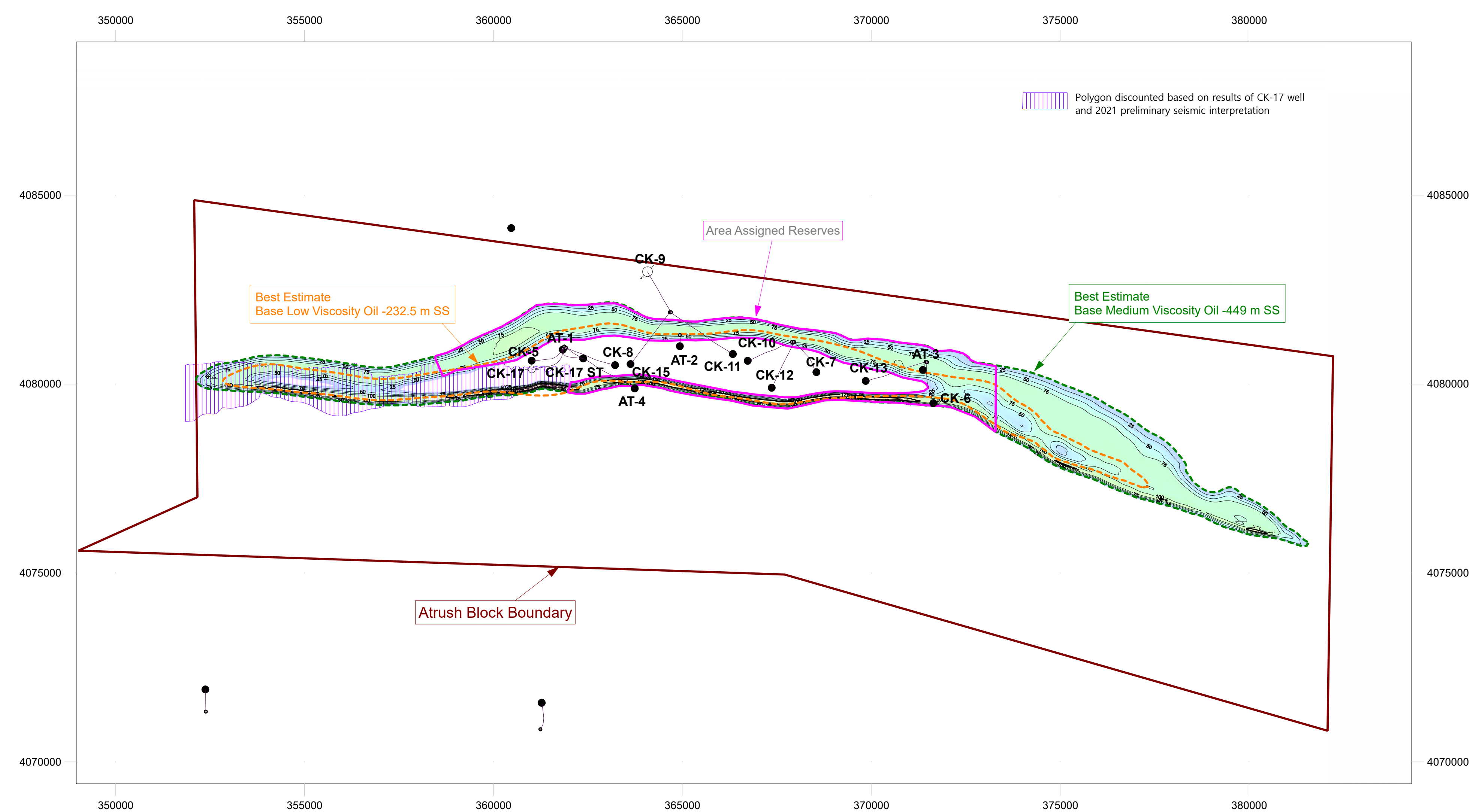
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Top Structure Map
Upper Sargelu Formation
Based on 2019 TAQA Interpretation
<AT>
Units – metres
15 November, 2021

Figure 10

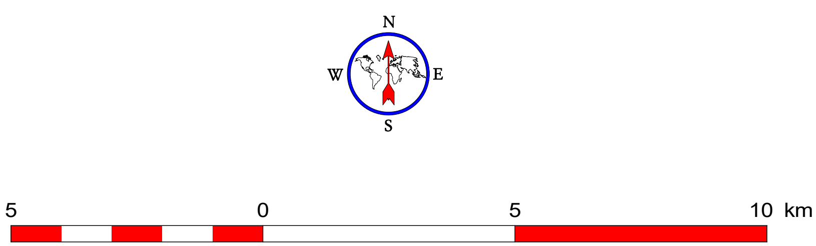


Polygon discounted based on results of CK-17 well and 2021 preliminary seismic interpretation
Area Assigned Reserves
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
Best Estimate
Base Low Viscosity Oil -232.5 m SS
Atrush Block Boundary
CK-9
CK-5
AT-1
CK-8
AT-2
CK-10
CK-11
CK-12
CK-7
CK-13
AT-3
CK-6
CK-17
CK-17 ST
CK-15
AT-4
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
LTG - Lowest Tested Gas
LTO - Lowest Tested Oil
LKO - Lowest Known Oil
5 0 5 10 km
McDANIEL
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Medium Oil – Best Estimate
Upper Sargelu Formation
<AT>
Units – metres
15 November, 2021

Figure 11



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
Gas well	NT - Not Tested
Status unknown	NP - Not Present
Abandoned	NDE - Not Deep Enough
Water injector	LTG - Lowest Tested Gas
Drilling location	LTO - Lowest Tested Oil
	LKO - Lowest Known Oil



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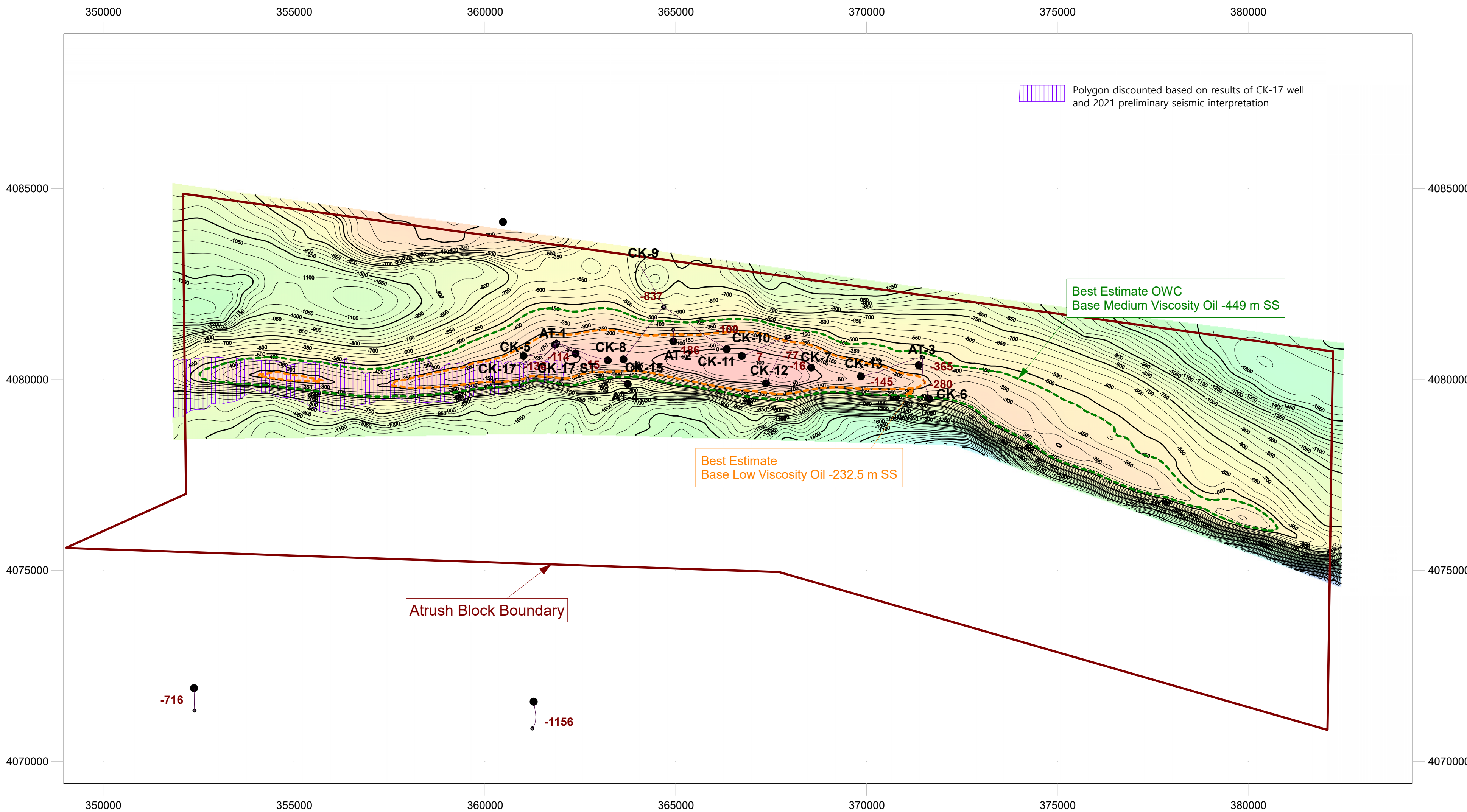
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Heavy Oil – Best Estimate
Upper Sargelu Formation

<AT>	Units – metres	15 November, 2021

Figure 12



Well Legend	Map Abbreviations
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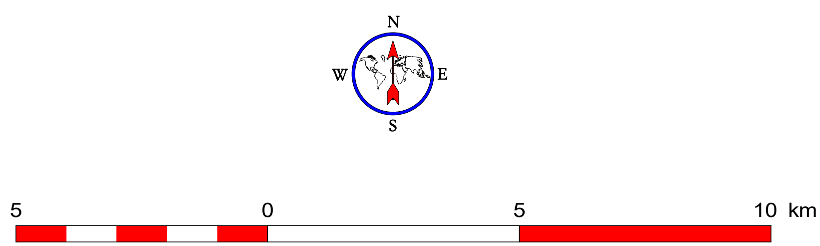
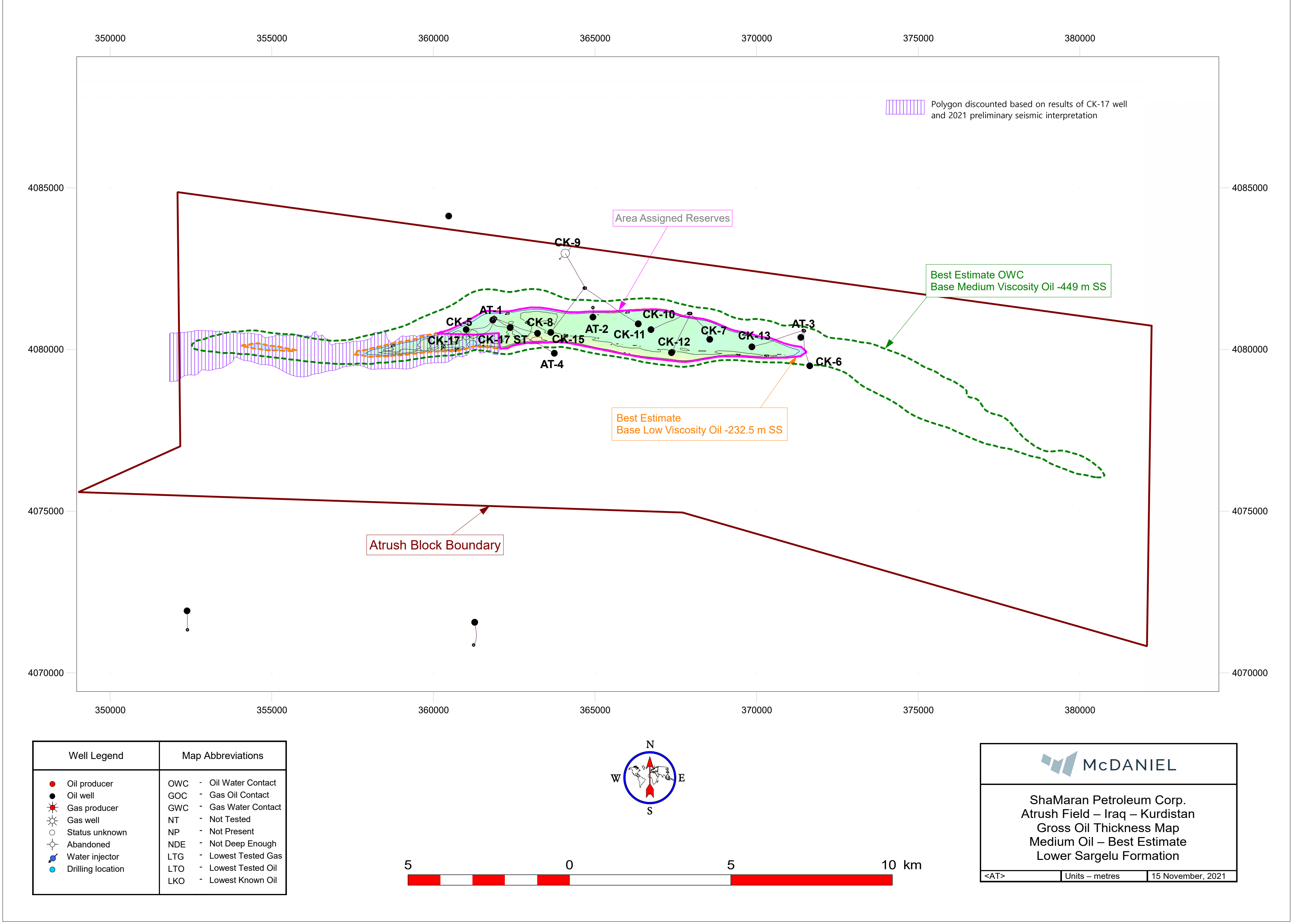


McDANIEL

ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Top Structure Map
Lower Sargelu Formation
Based on 2019 TAQA Interpretation

<AT>	Units – metres	15 November, 2021

Figure 13



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Polygon discounted based on results of CK-17 well and 2021 preliminary seismic interpretation
Area Assigned Reserves
CK-9
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
AT-1
CK-5
CK-8
AT-2
CK-10
CK-11
CK-7
CK-13
AT-3
CK-17
CK-17 ST
CK-15
CK-12
CK-6
AT-4
Best Estimate
Base Low Viscosity Oil -232.5 m SS
Atrush Block Boundary
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
LTG - Lowest Tested Gas
LTO - Lowest Tested Oil
LKO - Lowest Known Oil
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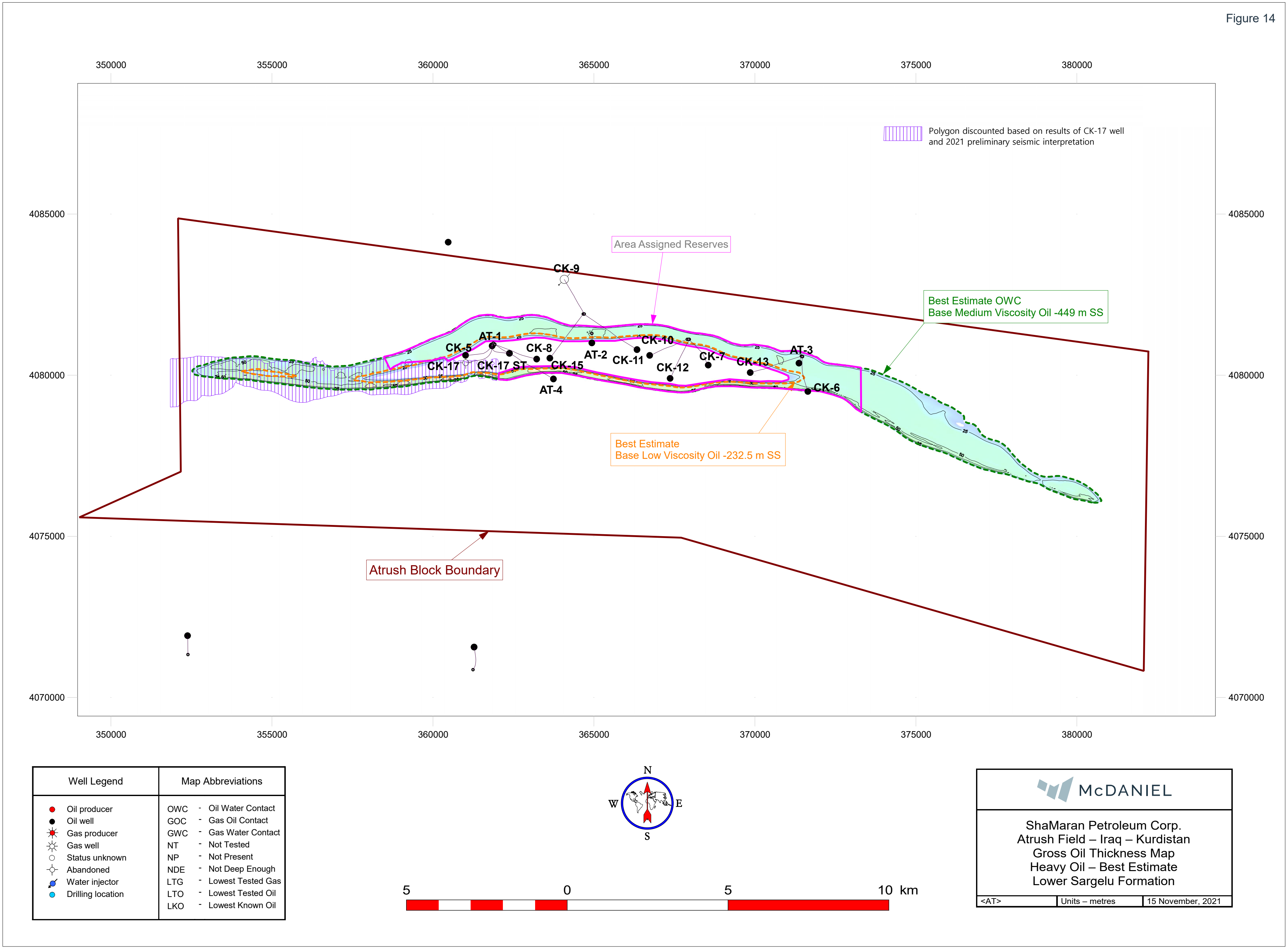
McDANIEL
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Medium Oil – Best Estimate
Lower Sargelu Formation
<AT>
Units – metres
15 November, 2021

Figure 14



Polygon discounted based on results of CK-17 well and 2021 preliminary seismic interpretation
Area Assigned Reserves
Best Estimate OWC
Base Medium Viscosity Oil -449 m SS
Best Estimate
Base Low Viscosity Oil -232.5 m SS
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CK-12
CK-7
CK-13
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Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
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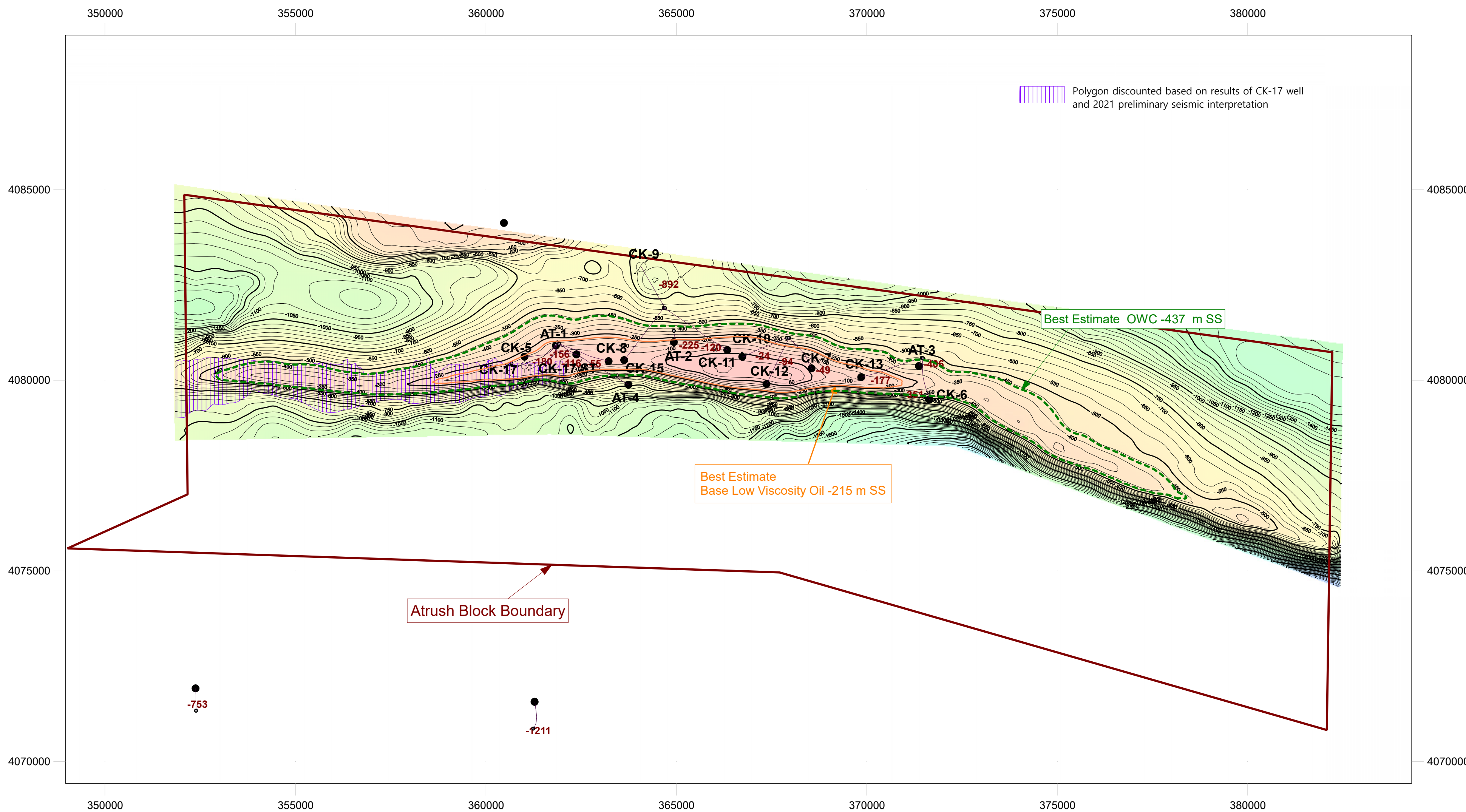
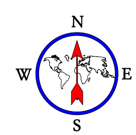
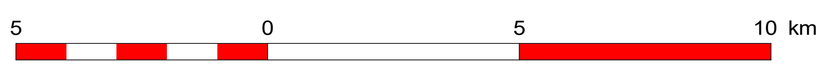
McDANIEL
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Heavy Oil – Best Estimate
Lower Sargelu Formation
<AT>
Units – metres
15 November, 2021

Figure 15







Well Legend	Map Abbreviations
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Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
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Drilling location	LTO - Lowest Tested Oil
	LKO - Lowest Known Oil

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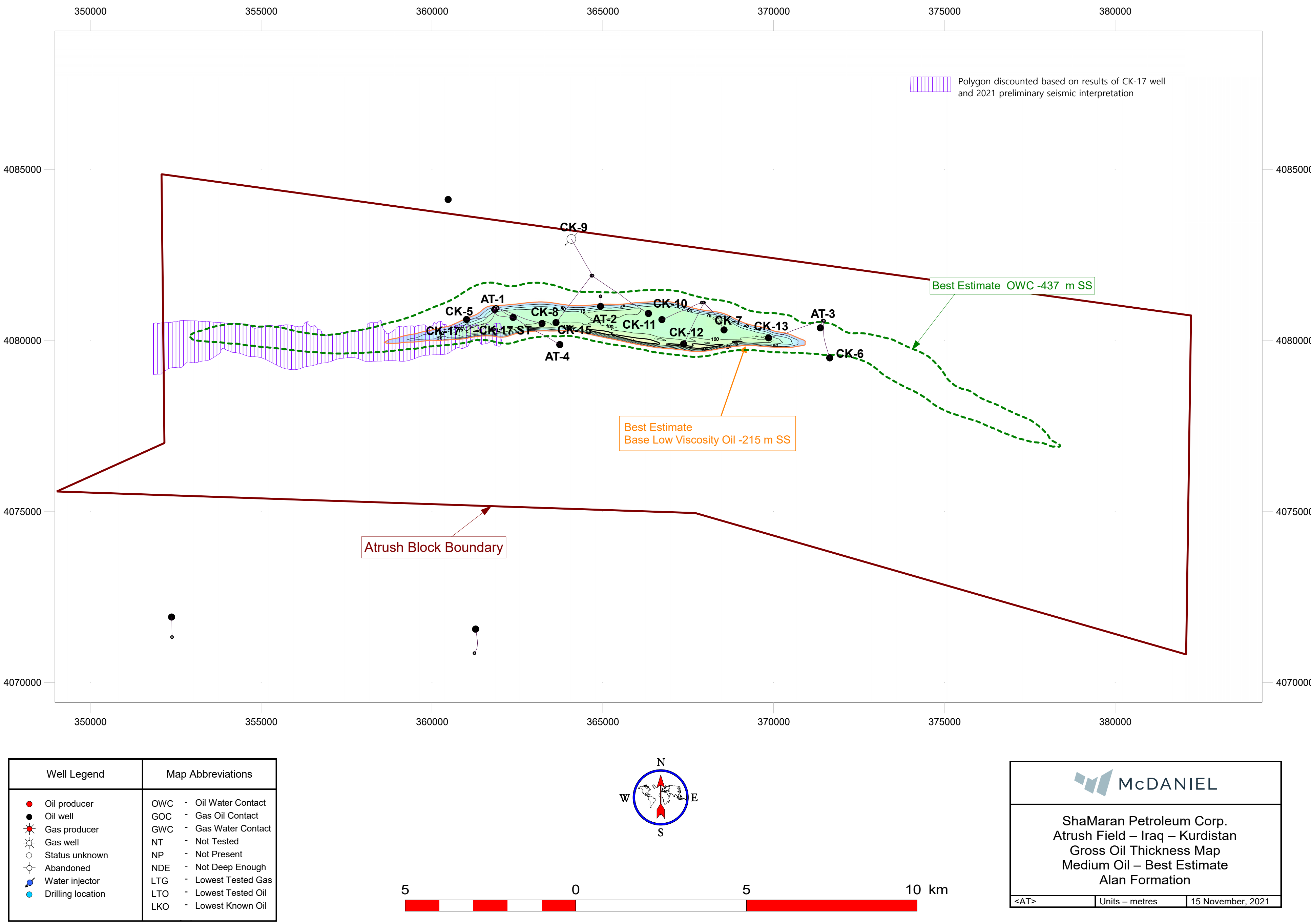
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Top Structure Map
Alan Formation
Based on 2019 TAQA Interpretation

<AT>	Units – metres	15 November, 2021

Figure 16



Well Legend	Map Abbreviations
Oil producer Oil well Gas producer Gas well Status unknown Abandoned Water injector Drilling location	OWC - Oil Water Contact GOC - Gas Oil Contact GWC - Gas Water Contact NT - Not Tested NP - Not Present NDE - Not Deep Enough LTG - Lowest Tested Gas LTO - Lowest Tested Oil LKO - Lowest Known Oil

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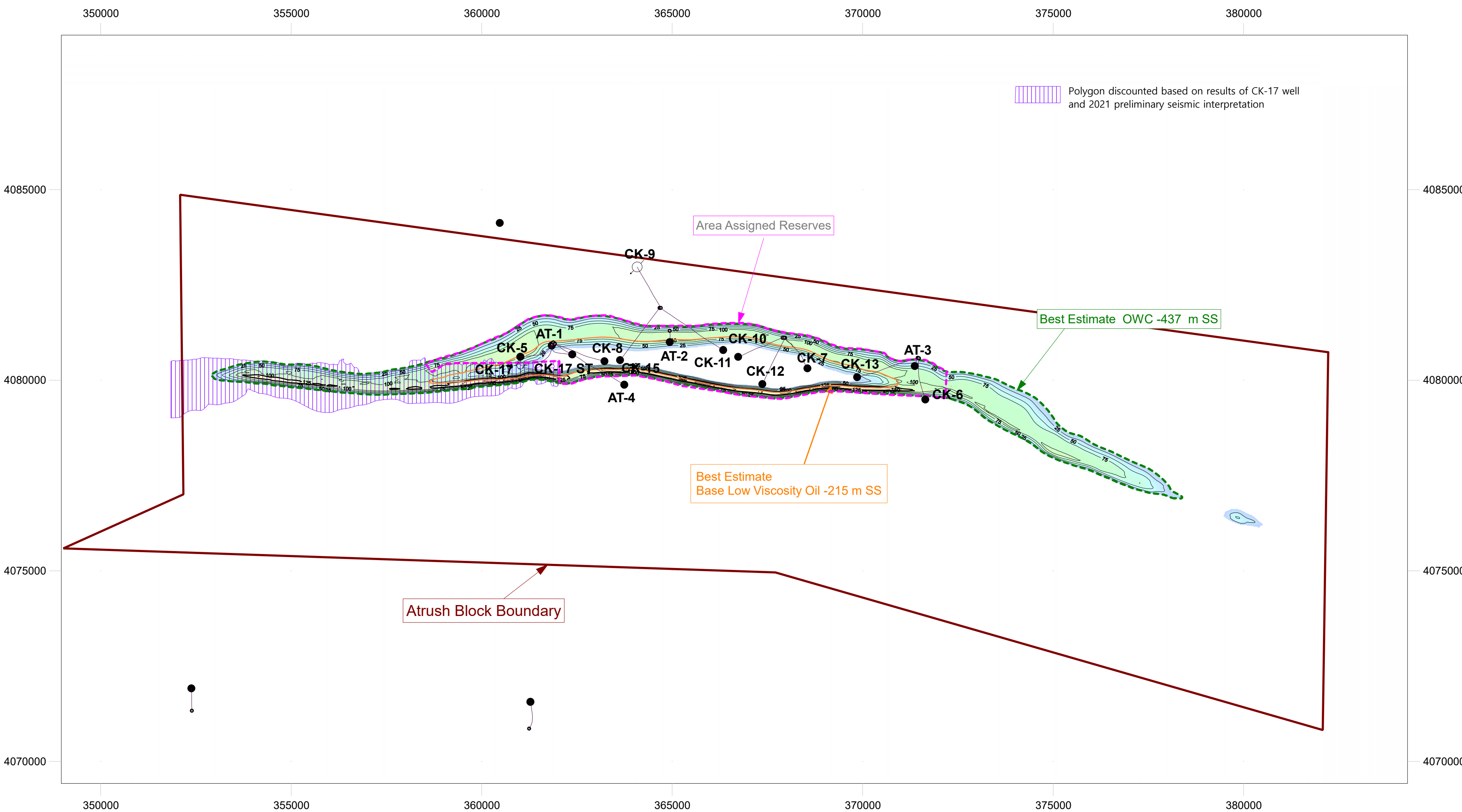
ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Medium Oil – Best Estimate
Alan Formation

<AT>	Units – metres	15 November, 2021

Figure 17



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
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Gas producer	GWC - Gas Water Contact
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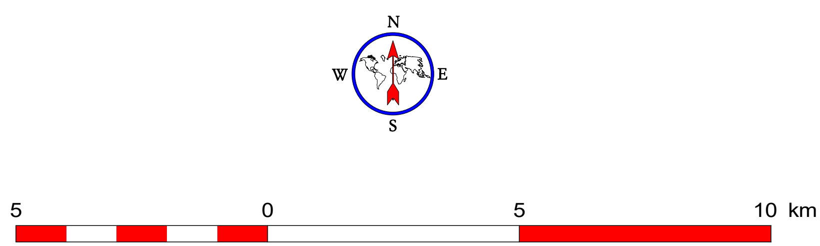
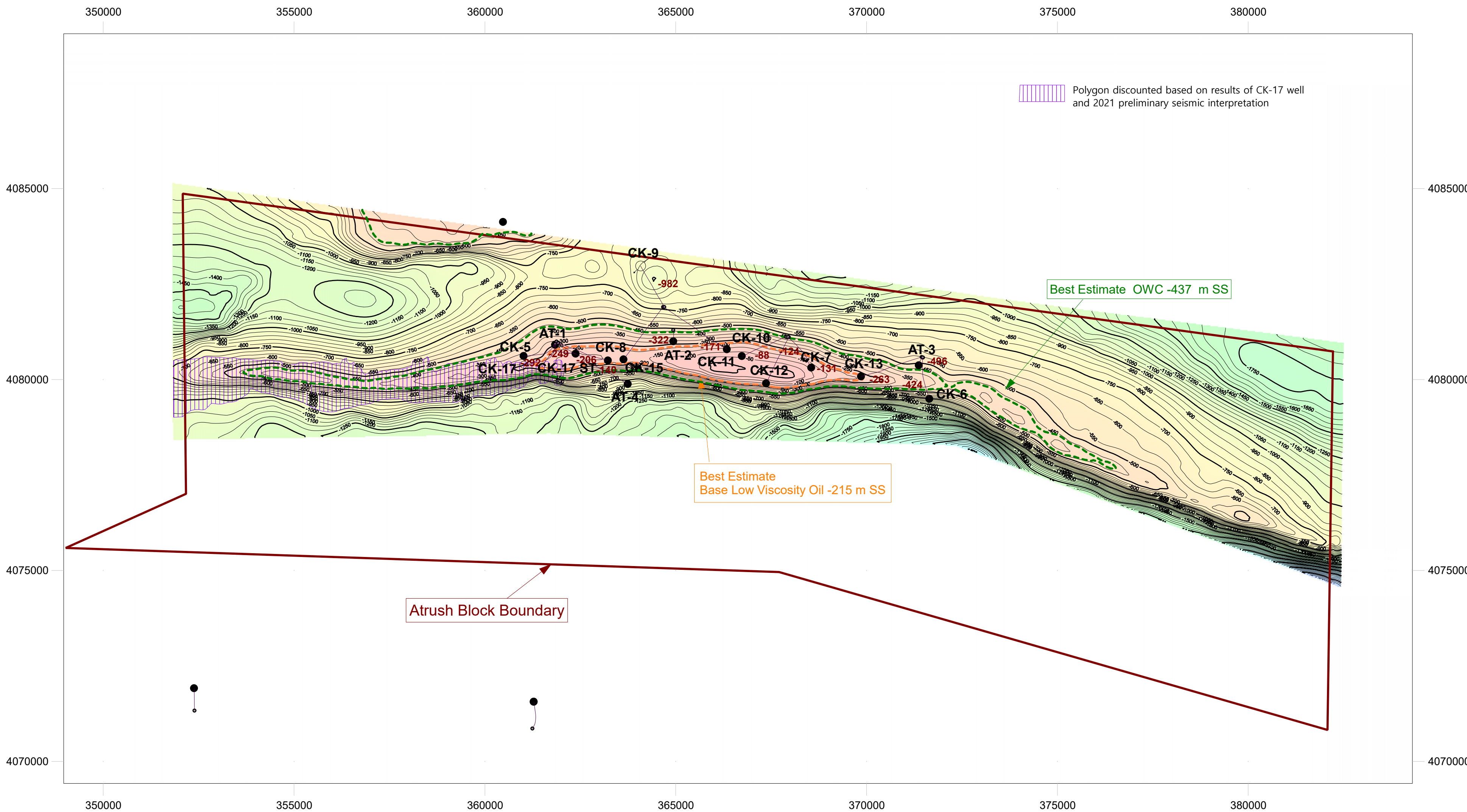


McDANIEL

ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Heavy Oil – Best Estimate
Alan Formation

<AT>	Units – metres	15 November, 2021

Figure 18



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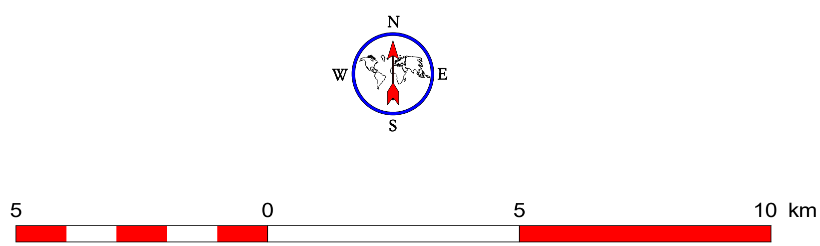
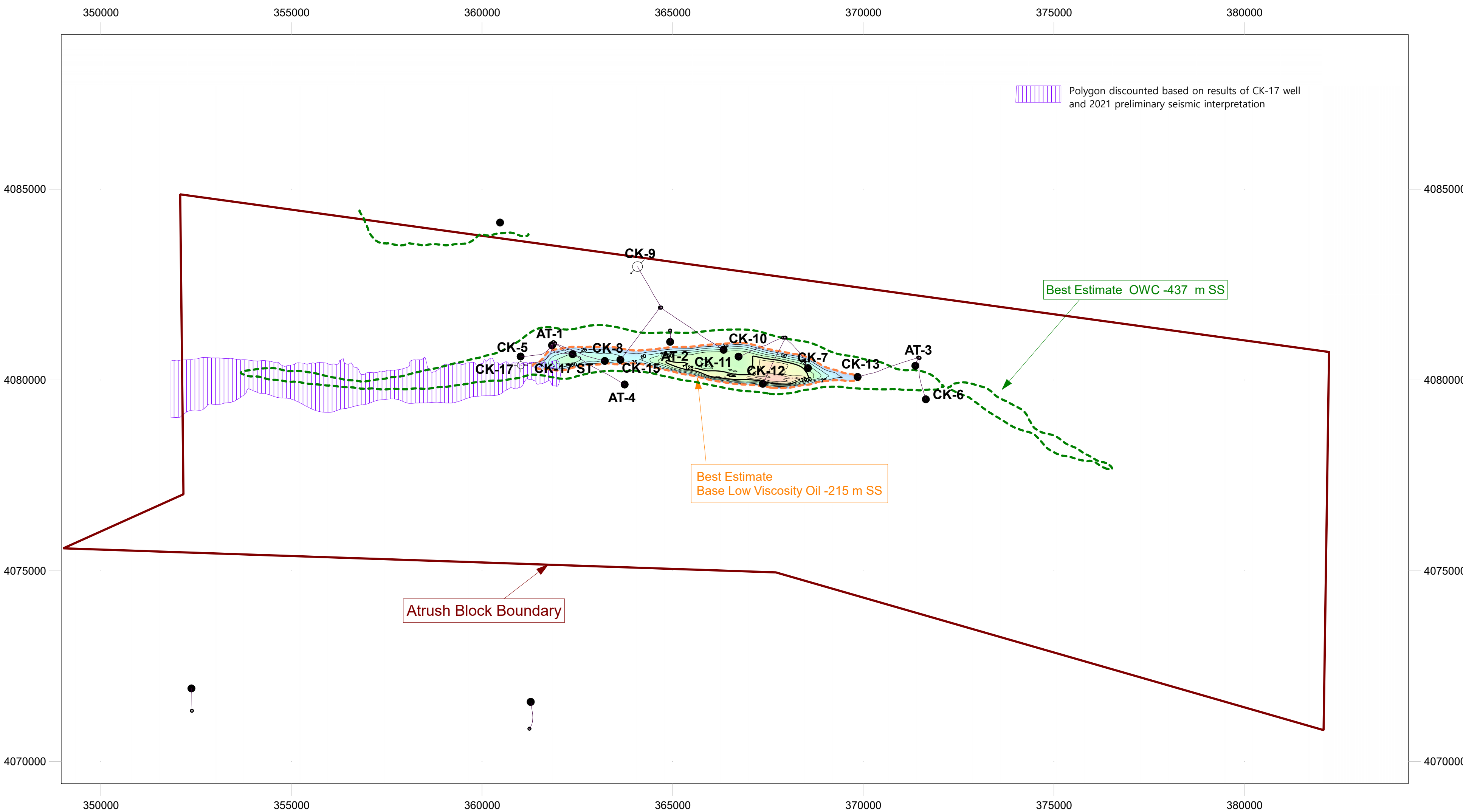


McDANIEL

ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Top Structure Map
Mus Formation
Based on 2019 TAQA Interpretation

<AT>	Units – metres	15 November, 2021

Figure 19



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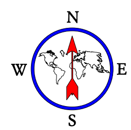
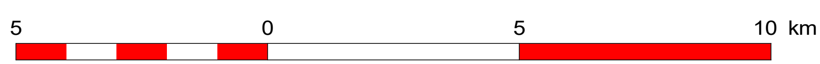


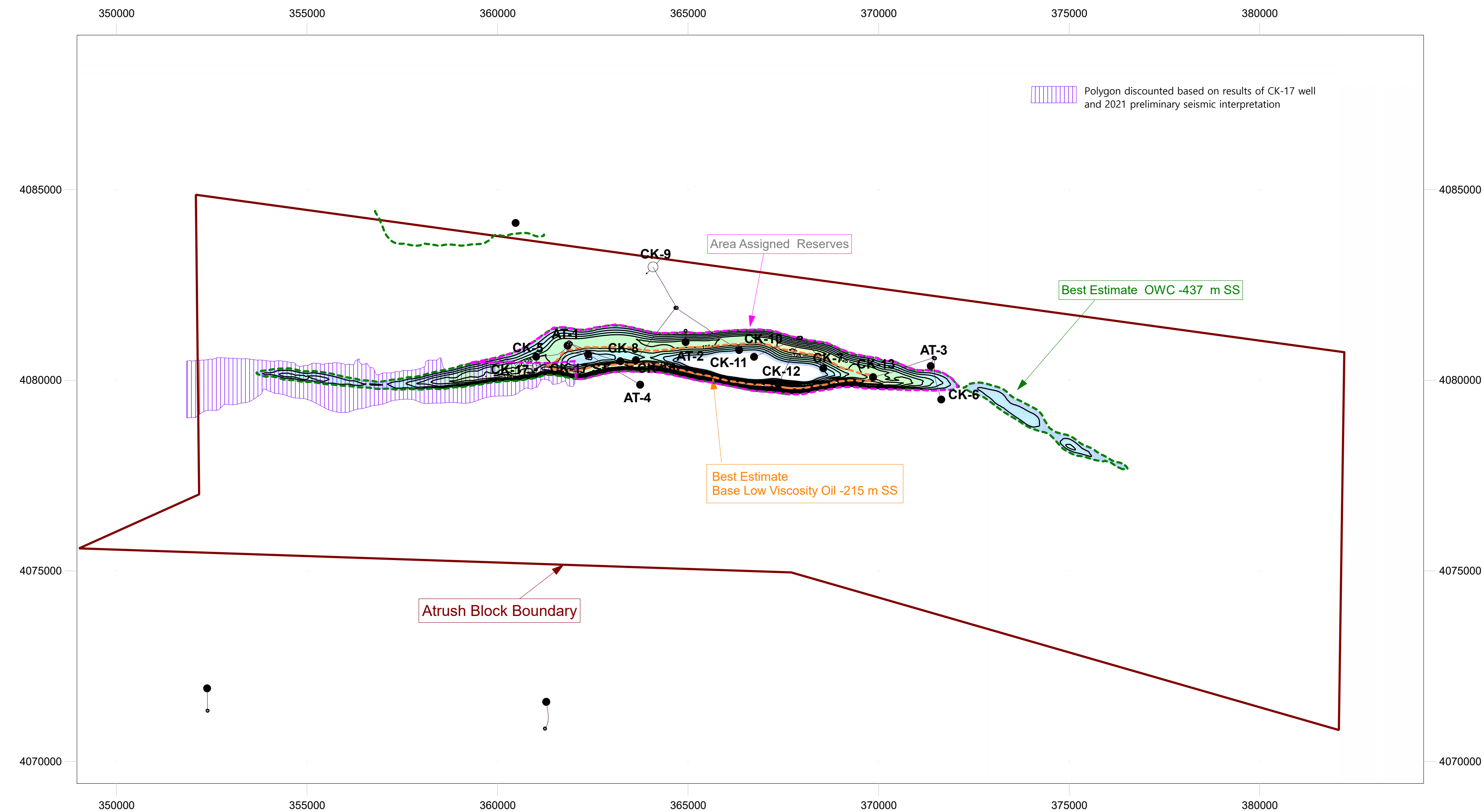


McDANIEL

ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Medium Oil – Best Estimate
Mus Formation

<AT>	Units – metres	15 November, 2021

Figure 20



Well Legend	Map Abbreviations
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McDANIEL

ShaMaran Petroleum Corp.
Atrush Field – Iraq – Kurdistan
Gross Oil Thickness Map
Heavy Oil – Best Estimate
Mus Formation

<AT>	Units – metres	15 November, 2021

Prices: McDaniel January 1, 2022
Eff. Date: December 31, 2021
Currency: USD

Figure 21

ShaMaran Petroleum Corp.
Total Field Crude Oil Production
100 Percent Working Interest Before Royalty
Atrush Field - Kurdistan Region