ORCA EXPLORATION GROUP INC.

Evaluation of Natural Gas Reserves
Songo Songo Field – Tanzania
As of December 31, 2012

Detailed Property Report

McDaniel
& Associates Consultants Ltd.

ORCA EXPLORATION GROUP INC.

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Songo Songo Field – Tanzania

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Prepared For:

Orca Exploration Group Inc.
Barclays House, 5th Floor
Ohio Street
P.O. Box 80139
Dar es Salaam, Tanzania

Prepared By:

McDaniel & Associates Consultants Ltd.
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April 2013

Orca Exploration Group Inc.
Evaluation of the Songo Songo Field

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Individual Wells

April 15, 2013

Orca Exploration Group Inc.
Barclays House, 5th Floor
Ohio Street
P.O. Box 80139
Dar es Salaam, Tanzania

Attention: Mr. Robert S. Wynne, Chief Financial Officer

Reference: **Orca Exploration Group Inc.**
Evaluation of Natural Gas Reserves
For the Songo Songo Field
Detailed Property Report

Dear Sir:

Pursuant to your request we have prepared an evaluation of the natural gas reserves and the net present values of these reserves for the interests of Orca Exploration Group Inc., hereinafter referred to as the "Company" or “Orca”, in the Songo Songo Field of Tanzania as of December 31, 2012.

The future net revenues and net present values presented in this report were calculated using forecast prices and costs based on our opinion of future natural gas prices at December 31, 2012 and were presented in United States dollars. The reserves estimates and future net revenue forecasts 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 (COGEH).

The Company's share of the natural gas reserves as of December 31, 2012 and the respective net present values assigned to these reserves based on forecast prices and costs were estimated to be as follows:

ESTIMATED COMPANY SHARE OF RESERVES
AS OF DECEMBER 31, 2012
MMCF

	Proved Producing	Proved Undeveloped	Total Proved	Probable	Proved & Probable	Possible	Proved, Probable & Possible
Natural Gas							
Gross (1)	279,965	149,217	429,182	60,128	489,310	323,534	812,844
Net (2)	181,194	87,843	269,037	37,268	306,305	206,171	512,476

(1) Gross reserves are defined as the aggregate of the Company interest reserves.
(2) Net reserves are based on Company share of Cost and Profit revenues.

ESTIMATED COMPANY SHARE OF NET PRESENT VALUES AS OF DECEMBER 31, 2012
$1000 U.S. (1) (2) (3) (4)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	457,889	312,825	226,236	171,968	136,374
Proved Undeveloped Reserves	164,521	148,492	127,682	107,512	89,760
Total Proved Reserves	622,410	461,317	353,918	279,480	226,135
Probable Reserves	86,524	51,876	31,614	19,415	11,889
Total Proved & Probable Reserves	708,934	513,193	385,532	298,894	238,023
Possible Reserves	360,240	164,512	79,384	40,488	21,714
Total Proved & Probable & Possible Reserves	1,069,174	677,704	464,916	339,383	259,737

(1) Based on "Forecast Prices" at December 31, 2012 (see Price Forecasts in Table 16).
(2) Includes In-Country G&A costs but excludes interest expenses and corporate overhead.
(3) The net present values may not necessarily represent the fair market value of the reserves.
(4) There is no defined income tax system in the Songo Songo PSC. Government share of revenues is through a royalty and Cost Revenue/Profit Revenue fiscal system.

The Company's share of reserves and net present values are presented on a total Company basis in Table 1. A map showing the location of the Songo Songo Field is presented in Figure 1. Tables summarizing the reserves, production and revenues for each of the various reserves classes are presented in Tables 2 to 8. Tables showing the reserves calculations and economic parameters are presented in the Tables 9 to 16 and geological maps for the various reservoirs assigned reserves are presented in Figures 8 to 14. A discussion of the geological interpretation of the field, and the methodology for estimating the reserves and revenue forecasts are presented in the Property Discussion section of this report.

The natural gas reserves estimates for the proved and proved plus probable reserves case presented in this report were based on Orca's share of production during the term of the production license ending October 11, 2026. Although it is likely that Orca's license will be extended, standard evaluation procedures in the oil and gas industry limit the Company share of reserves to the term of the existing license unless there is a clear and established track record of license extensions. A summary of the natural gas reserves and the future revenue forecasts to the end of the license are presented in Tables 1 to 4; however, for comparison, the reserves and future revenue forecasts are also presented to the end of the life of the field in Tables 1, 5, 6 and 7. A license extension was assumed in the proved plus probable plus possible case and, therefore, the natural gas reserves estimates are only presented to the end of field life as shown in Table 8.

In preparing this report, we relied upon certain factual information including ownership, well data, production data, prices, revenues, operating costs, capital costs, contracts, and other relevant data supplied by the Company. The supplied information was only relied upon where in our opinion it appeared reasonable and consistent with our knowledge of the properties however no independent verification of the information was made. We have also 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 date of this report, and that no new data has come to light that may result in a material change to the evaluation of the reserves presented in this report.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Orca Exploration Group Inc. and is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization other than Orca Exploration Group Inc. 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 or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

“signed by B. H. Emslie”	“signed by A. Tchernavskikh”
B. H. Emslie, P. Eng.	A. Tchernavskikh, P. Geol.

BHE/AT:jep
[12-0449]

CERTIFICATE OF QUALIFICATION

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

1. That I am a Senior Vice President of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of Orca Exploration Group Inc., the report entitled "Orca Exploration Group Inc., Evaluation of Natural Gas Reserves, Songo Songo Field – Tanzania, As of December 31, 2012, Detailed Property Report ", dated April 15, 2013; and that I was involved in the preparation of this report.

2. That I attended the University of Alberta in the years 1973 to 1980 and that I graduated with a Bachelor of Science Degree in Mechanical 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 thirty years of experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Orca Exploration Group Inc., any associate or 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 ALBERTA
BRYAN EMSLIE

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.
Senior Vice President

Calgary, Alberta
Dated: April 15, 2013

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 Orca Exploration Group Inc., the report entitled "Orca Exploration Group Inc., Evaluation of Natural Gas Reserves, Songo Songo Field – Tanzania, As of December 31, 2012, Detailed Property Report", dated April 15, 2013and that I was involved in the preparation of this report.

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 twenty years of experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Orca Exploration Group Inc., any associate or 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 GEOLOGIST ALBERTA
ANATOLI TCHERNAVSKIKH

"signed by A. V. Tchernavskikh"

A. V. Tchernavskikh, P. Geol.

Calgary, Alberta
Dated: April 15, 2013

Evaluation of Natural Gas Reserves
Songo Songo Field - Tanzania
As of December 31, 2012

Property Discussion

INTRODUCTION

Natural gas reserves estimates and their associated net present values were prepared in this report for the interests of Orca Exploration Group Inc. in the Songo Songo Field in Tanzania, East Africa. The reserves were estimated at December 31, 2012 and the revenue forecasts and net present value estimates were calculated using forecast prices and costs using our opinion of future natural gas prices at December 31, 2012 and were presented in United States dollars. The reserves estimates and future net revenue forecasts have been prepared in accordance with standards set out in the Canadian National Instrument NI 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGEH).

An overview of the Songo Songo Field and a detailed discussion of the methodology employed in arriving at the reserves and net present value estimates are presented in this report.

PROPERTY OVERVIEW

The Songo Songo Field is located both on and slightly offshore Songo Songo Island approximately 15 kilometres offshore of the coast of Tanzania, East Africa and 200 kilometres south of the Tanzanian city of Dar es Salaam (see Figure 1). Natural gas was initially discovered by AGIP in 1974; however, they relinquished the permit to the Tanzania Petroleum Development Corporation (TPDC) after drilling only one well. TPDC then drilled an additional eight wells between 1976 and 1983 resulting in a total of 9 wells in the field. Five of those wells are capable of production. Orca then drilled well SS-10 in 2007 and SS-11 in 2012.

Ocelot International Inc., later becoming an affiliate of Orca Exploration Group Inc., entered into an agreement with the TPDC in July 1991 to evaluate the economic viability of developing the field to generate electricity. Ocelot conducted an extensive well test program and minor reconditioning program in 1997 on five of the wells. The results of this testing program and prior technical studies were used to prepare a full field reservoir model. This led to the confirmation of sufficient quantities of natural gas to supply a gas to electricity project and submission of a formal development plan in May 2001.

Gas production from the Songo Songo Field commenced June 2004 and by the end of 2012 approximately 195 Bcf of gas had been produced. Performance to date has been excellent. Production history plots on a well and field basis are presented in the Appendix.

Raw gas is processed through a gas plant on Songo Songo Island then transported through a 25 kilometre pipeline to shore and a 207 kilometre pipeline to Dar es Salaam. The plant was recently re-certified to bring capacity up to 103 MMcfpd. The overall maximum capacity of the plant will be increased to 200 MMcfpd with the installation of two new trains that is expected to occur in 2014. In addition, the onshore and offshore pipelines will also be twinned to accommodate the additional volumes.

Ownership of the Songo Songo Gas Project is through a consortium called SONGAS with funding of the project obtained through equity ownership by Globeleq, EIB, TPDC and the Tanzania Electric Supply Company Limited and debt funding through the World Bank and EIB. SONGAS owns five of the wells, the gas processing plant, the pipelines and the power plant, although Orca is the operator of the reserves and gas processing plant on a no gain no loss basis. Gas reserves delivered to five of the six turbines in the Ubungo power generation facility, the Wazo Hill cement plant and about 1 MMcfpd of local use close to the pipeline are owned by SONGAS, but Orca will be entitled to market reserves on its behalf for additional sales above the dedicated SONGAS volumes.

In February 2012, the Government announced that it was setting up a Government Negotiation Team (‘GNT’) to discuss a number of issues in relation to the Company’s Production Sharing Agreement (‘PSA’) with the TPDC that was signed in October 2001. This includes, but is not limited to, TPDC back in rights, profit sharing arrangements, the unbundling of the downstream assets, cost recovery and Orca’s management of the upstream operations. After making submissions to the GNT, the Company commenced discussions in April 2012 and further in July 2012. In July 2012, Parliament dissolved the Parliamentary Committee for Energy and Minerals on the grounds of alleged widespread corruption and abuse of power. A Parliamentary team formed to investigate the allegations subsequently cleared Members of Parliament of any wrong doing. In July 2012 an agreement in principle was been reached on a number of major points to resolve the issues. The GNT has completed its mandate, and the responsibility for finalization, documentation and implementation has moved back to Ministry of Energy and Mines (“MEM”). As at the date of this report, a number of issues and conditions precedent remain to be fully resolved and documented. The outcome of the final negotiation may lead to material changes in the economic terms of the PSA, but cannot be estimated at this time.

GEOLOGY

Regional Geology

The Songo Songo Gas Field lies in the southern area of the offshore Tanzanian Coastal Basin. This basin is a seaward thickening sedimentary sequence that may reach thickness in excess of 10 kilometres. Although primarily regarded as mainly a marine Mesozoic – Cenezoic Basin, there may be a significant portion of the basin underlain by considerable thickness of the Permo-Triassic Karroo succession. The Coastal Basin has been viewed as a rifted or Atlantic type continental margin that is dominated by extensional tectonics.

The extensional rift margin was initiated in the Early Jurassic through E-W extension and rifting as Africa started to move away from Asia. The Late Jurassic to Early Cretaceous saw the onset of sea floor spreading as Madagascar continued to move now in a southwards direction from East Africa. Renewed rifting in the mid-Cretaceous (probably Aptian to Albian in age) caused reactivation of pre-existing extensional faults and the development of down to the east tilted fault blocks in the Songo Songo Region. Extension slowed soon after (Albian – Cenomanian) as relative motion between Madagascar and East Africa stopped, and in the Late Cretaceous spreading was initiated further east between Madagascar and India. In the Songo Songo Region the Late Cretaceous to Paleogene was a time of thermal subsidence and a thick succession of dominantly shale and claystone were deposited.

The start of the Miocene was a period of regional differential uplift that increases in magnitude to the west and is probably associated with development of the East African Rift system. In the Late Miocene to Recent, inversion occurred generating the Songo Songo regional high, and the field structure in its current form. Listric faults are formed over the Songo Songo structure with detachment on the base Eocene, and may have developed as a collapse of the growing inversion structure.

Stratigraphy

During the Late Jurassic to Late Cretaceous subsidence of the newly formed rift basin led to the deposition of shallow and deep water marine clastics over a large area. Sediments deposited include organic shales in the Upper Jurassic (penetrated by wells SS-1, SS-5, SS-7 and SS-8), thick shallow marine sands in the early Cretaceous, and deep water shales with intermittent delta front to turbidite fan and channel fill sands in the Late Cretaceous. Together these form the likely source rocks, thick Neocomian and Cenomanian natural gas reservoirs, and top seal in the Songo Songo Region. Rapid deposition during the Paleocene and early Eocene resulted in progradation of clastic shale wedges over a wide area. As subsidence slowed there was a return to shallow and marginal marine deposition and the Miocene is dominated by fine to medium grained sands deposited in these environments during a marine regressive phase. Quaternary coralline limestone and marine sands extend to the surface and reflect little change in the depositional environment during this period compared to the modern environments observed today.

The primary reservoir in the Songo Songo Field is the lower Cretaceous (Neocomian to Albian) sand sequence. These sands were deposited predominantly in shallow to marginal marine environments, with minor fluvial deposition in the Albian. The depositional environment varies little throughout the section from lower shoreface to upper shoreface to tidal sand flat. There is very little interpreted shale in this high net to gross system, which where present is interpreted to have been deposited in marsh, mudflat or lagoon environments. Reservoir quality is good, although it deteriorates with depth towards the base of the Neocomian.

The uppermost gas reservoir in the Songo Songo Field is the upper Cretaceous Cenomanian sequence, which consists of a generally thick gross interval of shale interbedded with sands and siltstones of varying thickness. The thickest Cenomanian interval on Songo Songo Field is found in the vicinity of the SS-1 and SS-3 wells, while reservoir quality sand only exists in wells SS-7 and SS-3 in the central area of the field. At SS-1 in the north the Cenomanian sand quality is marginal. The Cenomanian sands are thin to absent over the crest of the Songo Songo structure, in the vicinity of the SS-5, SS-7 and SS-9 wells, due to a combination of overburden structural influence and the disparate location of sands being shed off a delta front to the west or as deeper water turbidites.

The Neocomian – Albian and the Cenomanian reservoirs are overlain by a thick section of Late Cretaceous and Paleogene shales which form an excellent top seal. Although faults are mapped extending from the Neocomian upwards to the surface, as is evident on Songo Songo Field, they do not seem to present a seal risk, since they retain approximately 250 metres gas column in the Songo Songo Field.

The primary source rocks for the Songo Songo Region include the Permo-Triassic Karoo shales (gas) and Jurassic and Lower Cretaceous shales (oil and gas) which could have generated gas immediately beneath and to the east of the region. Cretaceous and Tertiary (Eocene) oil sources have the best chance of still being in the oil window at the present time and may present potential oil source rocks further to the east in deeper water. There are two potential routes for the gas migration – lateral migration from the deeper eastern part of the basin or vertical migration directly from the deeper Karoo and Jurassic sources. There is not enough data available right now to exactly identify gas source rocks.

Songo Songo Field Geology

The Songo Songo gas field is a long linear north-south trending domal structure cut by numerous minor faults and bounded on the east by a major fault with a throw of 200 to 300 feet. There have been several 2D seismic surveys over the field and the seismic quality was considered to be fair to poor due to the steeply dipping nature of some of the fault blocks and the difficulty of obtaining good data in the variety of surface terrains from deep water to shallow water to onshore terrain.

Orca conducted a detailed geophysical interpretation of the original 2D seismic data in 2002 and prepared an updated structural interpretation. This interpretation was less complex than previous interpretations, with one large north-south fault, cutting the crest of the structure between the SS-5, SS-7 and SS-9 group of wells and the SS-3 and SS-4 wells. Previous studies identified several fault blocks although a review of the new seismic interpretation, RFT data and detailed pressure interference testing conducted in 1997 indicated only the one major north-south fault. Pressure interference testing indicated that this fault is not sealing thus the entire structure is interpreted to have a common gas water contact.

Orca prepared an updated geological model in 2008 incorporating the latest structural mapping of the Top Cenomanian and Top lower Cretaceous (Neocomian to Albian) reservoirs from the 2D seismic data set. The model incorporates the reservoir zonation derived from a detailed stratigraphic correlation of well logs and has been tied to the new development Well SS-10. The petrophysical parameters have also been revised based on evaluation of the comprehensive wireline data acquired in SS-10, the first new data on the field for 25 years. This new structural interpretation was based on a new time to depth migration formula for the seismic data and was used to prepare the structure maps presented in this report for the top of the Cenomanian and the Neocomian as shown in Figures 6 and 7. There are a number of smaller displacement faults shown on the structure maps but only the main north-south fault on the east side of the field has a significant throw.

The natural gas reserves in this field are contained in a thick sequence of lower Cretaceous (Neocomian to Albian) age sands interbedded with silts, shales and carbonate layers and an overlying Cenomanian sand/shale sequence.

The top of the Cenomanian section occurs at a depth of approximately 1,635 metres sub-sea over the crest of the Songo Songo structure in the SS-10 Well as shown in Figure 8. The Cenomanian natural gas reservoir reaches a maximum gross thickness of 79 metres in the vicinity of the SS-4 Well as shown on Figure 12. The rapid facies changes resulted in a large variation in the thickness of the Cenomanian sand reservoir.

The top of the first lower Cretaceous reservoir was encountered at a sub-sea depth of 1,698 metres in the SS-5 Well over the crest of the Songo Songo structure while the gas water contact was interpreted to be at a depth of 1,940 metres. The gas water contact was estimated from RFT data since it was not possible to determine from well logs. The relative size of the aquifer is not well defined due to a lack of well data outside of the existing 11 wells.

The Albian-Neocomian section reaches a thickness of over 1,250 metres within the Songo Songo Area. The base of the Neocomian lies conformably on the Jurassic Kipatimu shales. The Neocomian reservoir becomes shalier and poorer quality in the lower part of the Neocomian section, which also coincides with the interpreted base of the gross gas pay interval.

Orca undertook a comprehensive review of all the basic geological, geophysical and engineering data in 2008. The petrophysical and structural review subdivided the gross Cenomanian / Neocomian section into 11 individual layers consisting of 1 Cenomanian layer and 10 Albian-Neocomian layers. All of the layers were interpreted to have a common gas-water contact at a depth of 1,940 metres subsea and only 8 of the 10 Neocomian layers were structurally high enough to be within the gas column. For mapping purposes, the 9 gas bearing layers were grouped into 4 layers referred to as the Cenomanian, the N-10 to N-6, N-5 and N-4 to N-1. Structure maps for the top of the Cenomanian and the Albian-Neocomian 10, Neocomian 5 and 4 layers are presented in Figures 7 to 10 and gross gas thickness maps for each of the four layers in Figures 11 to 14. The porosity and permeability correlations were reviewed with a modern CMR log interpretation and core data and established new porosity cutoffs. Orca prepared updated detailed petrophysical and geological interpretations in 2008 which were based on the petrophysical cutoffs.

Orca conducted a further update of the seismic depth conversion and petrophysics in 2011. The depth conversion update did not materially affect the main and southern area of the field but did increase the pool area and average thickness in the northern area of the field due to an increase in the top of the structure resulting in more of the zone being above the gas water contact. No material changes in the petrophysics occurred as a result of the petrophysical update.

The SS-11 Well was drilled in 2012 and is located roughly mid-way between the SS-5 and SS-3 wells. The well came in very close to the same depth as was predicted prior to drilling so the mapping was not revised.

Estimates of the Original Gas-in-Place and Petrophysical Parameters

The original gas-in-place ("OGIP") estimates for the Songo Songo Field were based on the four gross gas pay maps in Figures 11 to 14 and the reservoir parameters in Table 9. Separate OGIP estimates were prepared for the Total Proved ("1P"), Proved plus Probable ("2P") and Proved plus Probable plus Possible ("3P") reserves categories to reflect the respective confidence levels in the geological mapping. Further the northern area of the N10 to N6 pool was separated from the main area of the pool because of the lack of existing wells in the northern area and the less confidence in the quality of the reservoir in that area.

The OGIP estimate for the Cenomanian Unit was based on 50 percent of the mapped OGIP in the 1P reserves case, 75 percent in the 2P case and 125 percent in the 3P case to reflect the uncertainty over where the zone is present. No proved reserves were assigned to the northern area of the N10 to N6 pool due to the very limited well control. The OGIP estimates for the northern area of the N10 to N6 pool were based on 50 percent of the mapped OGIP in the 2P reserves case and 100 percent in the 3P case. The OGIP for the main area of the N10 to N6 pool and all other pools was based on 100 percent of the mapped OGIP.

A summary of the petrophysical parameters by layer is presented in Table 9.

RESERVES ESTIMATES

The natural gas reserves estimates for the Songo Songo Field were based on volumetric estimates. A summary of the petrophysical parameters, original gas in place ("OGIP") estimates and the recovery factors for each of the four layers are summarized in Table 9. The reserves were classified into Proved Producing ("PP"), Proved Undeveloped ("PUD"), Total Proved ("1P"), Proved plus Probable ("2P") and Proved plus Probable plus Possible ("3P") classes as defined in the Reserves Classification section of this report. A summary of various reservoir and fluid properties is also presented in Table 10.

The total field natural OGIP was estimated to be some 1,342, 1,521 and 1,717 Bcf on a 1P, 2P and 3P reserves basis respectively, based on the methodology for estimating the OGIP described above. Natural gas shrinkage is expected to be relatively low at 1.0 percent as the reservoir contains a sweet dry gas with a condensate ratio of only 0.6 bbl per MMcf. All of the condensate reserves are owned by TPDC.

In addition to volumetric estimates of the OGIP, material balance estimates were also prepared. There has been very detailed, accurate pressure data recorded on most of the wells since they started producing although it is still somewhat early in the life of the field to determine the strength of the aquifer with only about 12.5 percent of the 2P OGIP produced to date.

Further analysis of the total structure volume indicates that the aquifer volume is significantly larger than the gas volume thus the reservoir would very likely have a moderate to strong water drive. A numerical reservoir simulation was conducted by Orca which supports the view that the aquifer would provide pressure support to the gas pool although due to the very large size of the aquifer and the medium reservoir permeability, there would be a significant pressure gradient occurring throughout the reservoir with the lowest pressures near the producing wells.

The water drive effects make it very difficult to rely upon material balance calculations at this time. In our opinion, the volumetric method of estimating the OGIP is the most reliable method at this time and given the well control in the central area of the field where the majority of the OGIP is located, should provide confident estimates of the OGIP.

The recovery factors will depend on the extent of the gas water contact movement during the depletion of the gas pool, the reservoir pressure at abandonment and the amount of water coning that would occur in the gas wells which could limit their economic life. The pool is very thick thus water coning is not expected to be significant until very late in the pool life. The water contact movement and reservoir pressures as forecast in the reservoir simulation were analyzed to estimate recovery factors for each pool and reserves category as shown in Table 9. For the most part, overall average recovery factors of 67.5, 72.5, 75 and 80 percent for the PP, 1P, 2P and 3P reserves cases respectively were assigned to all of the pools in the main area of the field with somewhat lower recovery factors for the northern area of the N10 to N6 pool since only one production well was forecast to be drilled in that area.

Only a portion of the technically recoverable reserves from the field are owned by Orca. Orca is entitled to only those “Additional” volumes in excess of the “Protected” volumes dedicated to SONGAS. A breakdown between the Additional and Protected sales gas reserves was based on year by year production forecasts and is summarized at the bottom of Table 9.

In addition, for the 1P and 2P reserves case only the Additional production volumes during the term of the license, to October 11, 2026, were classified as Company owned reserves. Although it is likely that Orca’s license will be extended, standard evaluation procedures in the oil and gas industry limit the Company share of reserves to the term of the existing license unless there is a clear and established track record of license extensions. A license extension was assumed in the

3P case and, therefore, the natural gas reserves estimates were based on production to the end of field life. A summary of the reserves to the end of the license as well as to the end of the life of the field are presented in Table 1.

RESERVES CLASSIFICATION

The natural gas reserves estimates presented in this report have been based on the Canadian reserves definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the COGE Handbook. A summary of those definitions is presented below.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates

- **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 plus 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 plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

- **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

- **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 (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

PRODUCTION FORECASTS AND DEVELOPMENT PLANS

Production forecasts for the Additional Gas sales in the PP, 1P, 2P and 3P reserves categories were prepared for the Songo Songo Field in Tables 2 to 8. A graphical presentation of the production forecasts for the PP, 1P, 2P and 3P reserves categories is also presented in Figures 2 to 6.

Terms of the SONGAS agreement call for natural gas sales to five of the six turbines in the Ubungo power generation facility, the Wazo Hill Cement Plant and about 1 MMcfpd of local use close to the pipeline to be owned by the SONGAS consortium (referred to as the Protected Volumes) with any volumes above this amount to be owned by Orca (referred to as Additional Volumes). The Protected Volume contract has a 20 year term from the commencement of production then all subsequent sales will be owned by Orca. The max day production rate for the Protected Volumes is approximately 45.1 MMcfpd of sales gas. The Protected Volume load factor is forecast at 85 percent resulting in a remaining Protected Volume of approximately 162 Bcf of sales gas to the end of the 20 year term.

The SONGAS agreement requires that the max day rate for the Protected Volume sales to the Ubungo and cement plants to be maintained throughout the 20 year period. Although the deliverability from the existing wells is well above the 45.1 MMcfpd max day requirement, Orca must drill additional wells in the future to allow for Additional Volume sales to new markets.

Orca's Additional Volumes are comprised of industrial contracts and sales to power generation facilities in Dar es Salaam. Orca was selling gas to 33 industrial gas customers in Dar es Salaam in 2012. Additional industrial markets are being pursued by Orca which will likely result in the Additional Volumes steadily increasing over the next few years. Production rates for the industrial sales averaged approximately 6.1 MMcfpd in 2012 and are forecast to reach 10.0 MMcfpd by 2018 in the 2P case. Production rates for the Wazo Hill cement plant averaged approximately 4.0 MMcfpd in 2012 and are forecast to reach 8.0 MMcfpd by 2018 in the 2P case.

Orca's sales to the power sector averaged approximately 37.8 MMcfpd in 2012 and are forecast to rise to 112 MMcfpd by 2015 in the 2P case as new gas fired power generation facilities are added.

The PP reserves case was based on production rates that can be processed by the existing gas plant while the 1P, 2P and 3P reserves cases included a plant expansion at the end of 2014.

The PP reserves case forecast the total Additional Volume sales to be relatively constant at 53.4 MMcfpd until they increase in 2024 when the Protected gas sales end. The 1P reserves case forecast Additional Volume sales to increase from 51 MMcfpd in 2013 to 130 MMcfpd by 2015 then start to decline in 2020. The 2P reserves case forecast Additional Volume sales to increase from 53.5 MMcfpd in 2013 to 135 MMcfpd by 2015 then start to decline in 2021. The 3P reserves case forecast Additional Volume sales to increase from 53.5 MMcfpd in 2013 to

140 MMcfpd by 2015 then start to decline in 2022. Production forecasts for the total field average sales gas rates for each reserves category are shown graphically in Figures 2 to 6.

One proved undeveloped location were forecast to be drilled in 2014, one probable undeveloped drilling location in 2015 and one possible undeveloped location in 2017. Two new processing trains and plant inlet compression were forecast to be installed by the end of 2014. All of the gas plant and compression expenditures were assumed to be paid by SONGAS or another third party so Orca would pay a processing fee. A summary of the expenditures is presented in Tables 12 to 15.

REVENUE FORECASTS

The net present values of the natural gas reserves assigned to the Songo Songo Field were based on future production and revenue analyses. All of the revenues and costs forecast in this report are presented in US dollars.

Orca currently owns a 100 percent interest in all of the Additional Volumes however TPDC has an option to participate in the drilling of any new wells for 5 to 20 percent of the cost of the wells in return for an additional 5 to 20 percent higher profit revenues on the allocated production to each well. It was assumed that TPDC would exercise its option for 20 percent on all new wells. TPDC will assume obligations for all operating and capital costs associated with their share of production for each well in which it backs into and be entitled to cost recovery, so this participation was treated as a working interest. The net result is that Orca's field average working interest in the Additional Volumes over the life of the reserves is approximately 90 percent.

As discussed in the reserves section of this report, Orca was only assigned reserves representing its share of the Additional Volumes during the term of the production license in the PP, 1P and 2P cases. Future revenue forecasts and net present value estimates were, however, prepared for both the revenues to the end of the license term for the PP, 1P and 2P cases (see Tables 2 to 4), and, in a scenario where the license is renewed to the end of the field economic life for the PP, 1P, 2P and 3P cases (see Tables 5 to 8).

Future natural gas revenues were based on forecasts of the industrial, Wazo Hill and power market sales volumes and the respective price forecasts for each market. A summary of the Songo Songo industrial and power gas price forecast is presented in Table 16.

The fiscal regime for Songo Songo is detailed in Table 11. Government share of revenues is through a royalty and cost revenue/profit revenue fiscal system and there is no defined income tax system. Operating and capital costs were based on estimates provided by the Company and are summarized in Tables 11 to 15. The SONGAS agreement was recently revised to establish a gas plant processing and transmission fee of $0.59/Mcf for all of the Additional Volumes sales. This fee is expected to increase in 2015 as the gas plant is expanded. Additional operating expenses are incurred for the well and field gathering system, a company owned gas distribution system in Dar es Salaam, a regulator fee, marketing expenses and G&A costs. Abandonment costs were included in the revenue forecasts to the end of the field life but not in the cases that only go to the end of the license terms since the wells would still be producing. Capital cost estimates were provided by the Company and are comprised of new wells, wellhead compression, plant and pipeline expansion and a distribution system expansion.

Orca Exploration Group Inc.

Table 1

Songo Songo Field Tanzania - Additional Volumes Only

Summary of Reserves and Net Present Values

Forecast Price Case as of December 31, 2012

Summary of Reserves (1), (3)

Reserve Category	Natural Gas Reserves - To End of License: Property Gross (2) MMcf	Company Gross (2) MMcf	Company Net (2) MMcf	Natural Gas Reserves - To End of Field Life: Property Gross (2) MMcf	Company Gross (2) MMcf	Company Net (2) MMcf
Proved Producing Reserves	306,122	279,965	181,194	541,190	492,601	314,809
Proved Undeveloped Reserves	170,844	149,217	87,843	66,430	54,243	34,577
Total Proved Reserves	476,965	429,182	269,037	607,621	546,844	349,386
Probable Reserves	68,343	60,128	37,268	126,088	111,395	68,218
Proved Plus Probable Reserves	545,308	489,310	306,305	733,709	658,239	417,603
Possible Reserves	362,518	323,534	206,171	174,118	154,605	94,872
Proved + Probable + Possible (5)	907,827	812,844	512,476	907,827	812,844	512,476

Summary of Company Share of Net Present Values - Forecast to End of License (3)

Reserve Category	$M US Dollars - Unrisked: 0.0%	5.0%	10.0%	15.0%	20.0%
Proved Producing Reserves	457,889	312,825	226,236	171,968	136,374
Proved Undeveloped Reserves	164,521	148,492	127,682	107,512	89,760
Total Proved Reserves	622,410	461,317	353,918	279,480	226,135
Probable Reserves	86,524	51,876	31,614	19,415	11,889
Proved Plus Probable Reserves	708,934	513,193	385,532	298,894	238,023
Possible Reserves	360,240	164,512	79,384	40,488	21,714
Proved + Probable + Possible (5)	1,069,174	677,704	464,916	339,383	259,737

Summary of Company Share of Net Present Values - Forecast to End of Field Life (3)

Reserve Category	$M US Dollars - Unrisked: 0.0%	5.0%	10.0%	15.0%	20.0%
Proved Producing Reserves	802,278	462,001	293,861	203,971	152,130
Proved Undeveloped Reserves	(107,515)	35,588	78,076	84,564	78,646
Total Proved Reserves	694,763	497,589	371,938	288,535	230,776
Probable Reserves	163,332	83,049	44,847	25,302	14,631
Proved Plus Probable Reserves	858,095	580,637	416,785	313,837	245,407
Possible Reserves	211,079	97,067	48,131	25,545	14,330
Proved + Probable + Possible	1,069,174	677,704	464,916	339,383	259,737

(1) Company Gross reserves are based on Orca's working interest share of the property gross additional reserves (excluding protected volumes).
Company Net reserves are based on Orca's share of total Cost and Profit Revenues.
(2) Additional Volumes Only (Excludes Protected Volumes).
(3) Only the reserves and net present values to end of license were included at the corporate level.
(4) There is no defined corporate income tax for this property. Government share of revenue is through a Cost Revenue/Profit Revenue fiscal sytem.
(5) A license extension was assumed in the proved plus probable plus possible reserves case

Orca Exploration Group Inc.

Table 2

Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Proved Producing Reserves
Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Dar Gas Price US$/Mcf	Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	39.85	6.69	0.39	4.43	89.69	51.35	18,744	4.84	90,780	11,059	79,721
2014	6	38.34	40.30	7.36	0.47	5.31	91.77	53.44	19,505	4.91	95,840	11,508	84,332
2015	7	38.34	38.68	8.00	0.56	6.20	91.77	53.44	19,505	6.27	122,232	35,545	86,686
2016	7	38.34	37.95	8.00	0.67	6.82	91.77	53.44	19,505	6.32	123,325	35,545	87,780
2017	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.37	124,258	35,545	88,712
2018	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.46	126,066	35,545	90,521
2019	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.56	127,861	35,545	92,316
2020	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.65	129,713	35,545	94,167
2021	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.74	131,552	35,545	96,006
2022	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.85	133,519	35,545	97,974
2023	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.94	135,439	35,545	99,894
2024	7	22.36	53.16	8.00	0.75	7.50	91.77	69.41	25,335	7.07	179,058	46,170	132,888
2025	7	-	75.52	8.00	0.75	7.50	91.77	91.77	33,497	7.19	240,830	61,045	179,785
2026	7	-	75.52	8.00	0.75	7.50	91.77	91.77	33,497	7.30	244,409	61,045	183,365
2027													
Rem.													
Total		162,077	226,781	40,166	3,497	35,678	468,199	306,122	306,122	6.55	2,004,882	510,734	1,494,148

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,579	0.88	-	6,935	80	200	20,395	59,791	20,775	-	58,947
2014	17,485	0.90	-	39,164	82	200	54,548	63,249	54,548	-	29,784
2015	15,866	0.81	-	957	83	200	17,178	65,015	17,178	-	69,508
2016	16,232	0.83	-	976	85	200	17,570	65,835	17,570	-	70,210
2017	16,585	0.85	-	996	87	200	17,950	66,534	17,950	-	70,763
2018	16,907	0.87	-	1,016	88	200	18,012	67,890	18,012	-	72,509
2019	17,236	0.88	-	1,036	90	200	18,362	69,237	18,362	-	73,953
2020	17,572	0.90	-	1,057	92	200	18,720	70,626	18,720	-	75,447
2021	17,913	0.92	-	1,078	94	200	19,085	72,005	19,085	-	76,921
2022	18,263	0.94	-	1,099	96	200	19,458	73,480	19,458	-	78,516
2023	18,619	0.95	-	1,121	98	200	19,838	74,920	19,838	-	80,056
2024	19,966	0.79	-	1,144	99	200	21,209	99,666	21,209	-	111,679
2025	21,755	0.65	-	634	101	200	22,490	134,839	22,490	-	157,295
2026	22,174	0.66	-	647	103	200	22,924	137,524	22,924	-	160,441
2027											
Rem.											
Total	253,152	0.83	-	57,861	1,278	2,800	307,740		308,120		1,186,029

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,220	10,940	18,475	28,055	46,530	13,851	6,651	267	-	25,762	25,762	24,563
2014	17,585	15,624	52,785	14,769	67,554	15,382	39,051	272	-	12,849	38,611	11,137
2015	17,960	11,457	15,715	35,201	50,917	14,330	865	275	6,053	29,394	68,005	23,162
2016	17,960	11,471	16,069	35,557	51,626	14,660	882	277	8,952	26,855	94,860	19,238
2017	17,960	11,488	16,412	35,837	52,249	14,979	899	278	9,023	27,069	121,929	17,628
2018	17,960	11,461	16,468	36,721	53,189	15,271	917	280	9,180	27,541	149,470	16,305
2019	17,909	11,425	16,726	37,346	54,072	15,513	932	281	9,337	28,010	177,479	15,075
2020	17,909	11,423	17,048	38,101	55,149	15,815	951	283	9,525	28,576	206,055	13,981
2021	17,909	11,422	17,377	38,845	56,222	16,122	970	284	9,711	29,134	235,189	12,959
2022	17,909	11,420	17,712	39,650	57,363	16,437	990	286	9,913	29,738	264,927	12,025
2023	17,909	11,419	18,054	40,428	58,482	16,757	1,009	288	10,107	30,321	295,248	11,146
2024	23,262	14,429	19,288	56,398	75,686	17,969	1,030	290	14,099	42,298	337,546	14,135
2025	30,756	18,609	20,441	79,434	99,875	19,579	571	291	19,858	59,575	397,122	18,099
2026	30,756	18,607	20,832	81,023	101,854	19,956	582	293	20,256	60,767	457,889	16,783
2027												
Rem.												
Total	279,965	181,194	283,403	597,366	880,769	226,621	56,300	3,944	136,014	457,889		226,236

Orca Exploration Group Inc.

Table 3

Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Total Proved Reserves
Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Dar Gas Price US$/Mcf	Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	39.47	6.69	0.39	4.43	89.31	50.97	18,605	4.84	90,107	10,977	79,130
2014	6	38.34	40.30	7.36	0.47	5.31	91.77	53.44	19,505	4.91	95,840	11,508	84,332
2015	8	38.34	115.21	8.00	0.56	6.20	168.30	129.97	47,437	6.27	297,332	86,449	210,884
2016	8	38.34	114.48	8.00	0.67	6.82	168.30	129.97	47,437	6.34	300,910	86,449	214,461
2017	8	38.34	113.72	8.00	0.75	7.50	168.30	129.97	47,437	6.42	304,376	86,449	217,927
2018	8	38.34	113.72	8.00	0.75	7.50	168.30	129.97	47,437	6.51	308,769	86,449	222,320
2019	8	38.34	113.72	8.00	0.75	7.50	168.30	129.97	47,437	6.60	313,199	86,449	226,751
2020	8	38.34	99.43	8.00	0.75	7.50	154.02	115.68	42,225	6.69	282,654	76,950	205,704
2021	8	38.34	78.72	8.00	0.75	7.50	133.31	94.97	34,664	6.78	235,086	63,172	171,915
2022	8	38.34	62.00	8.00	0.75	7.50	116.59	78.25	28,563	6.87	196,290	52,052	144,237
2023	8	38.34	46.31	8.00	0.75	7.50	100.90	62.56	22,835	6.96	158,854	41,613	117,241
2024	8	22.36	48.72	8.00	0.75	7.50	87.33	64.97	23,713	7.06	167,485	43,215	124,271
2025	8	-	55.72	8.00	0.75	7.50	71.97	71.97	26,269	7.18	188,483	47,873	140,610
2026	8	-	47.86	8.00	0.75	7.50	64.11	64.11	23,399	7.27	170,182	42,643	127,540
2027													
Rem.													
Total		162,077	397,624	40,166	3,497	35,678	639,042	476,965	476,965	6.52	3,109,568	822,246	2,287,322

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,524	0.89	-	6,935	80	200	20,381	59,347	20,761	-	58,369
2014	17,485	0.90	-	79,204	82	200	88,863	63,249	63,249	25,614	21,083
2015	19,091	0.40	-	10,536	83	200	23,362	158,163	48,977	-	161,907
2016	19,508	0.41	-	7,158	85	200	25,207	160,846	25,207	-	189,254
2017	19,913	0.42	-	1,537	87	200	26,809	163,446	26,809	-	191,119
2018	20,289	0.43	-	1,568	88	200	27,035	166,740	27,035	-	195,285
2019	20,672	0.44	-	1,599	90	200	25,972	170,063	25,972	-	200,778
2020	20,447	0.48	-	1,631	92	200	23,623	154,278	23,623	-	182,081
2021	19,913	0.57	-	1,664	94	200	21,670	128,936	21,670	-	150,245
2022	19,521	0.68	-	1,697	96	200	21,314	108,178	21,314	-	122,923
2023	19,138	0.84	-	1,731	98	200	20,967	87,931	20,967	-	96,274
2024	19,836	0.84	-	1,766	99	200	21,701	93,203	21,701	-	102,570
2025	20,996	0.80	-	951	101	200	22,049	105,458	22,049	-	118,562
2026	21,051	0.90	-	970	103	200	22,125	95,655	22,125	-	105,415
2027											
Rem.											
Total	274,384	0.58	-	118,947	1,278	2,800	391,077		391,457		1,895,865

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,100	10,873	18,464	27,780	46,244	13,805	6,651	267	-	25,521	25,521	24,334
2014	17,396	15,088	54,891	10,342	65,233	15,175	71,523	271	-	(21,735)	3,786	(18,840)
2015	42,838	28,439	46,009	80,416	126,425	16,829	9,288	273	11,123	88,913	92,698	70,062
2016	42,838	25,751	22,420	93,999	116,419	17,196	6,310	275	23,160	69,479	162,177	49,771
2017	42,838	25,850	23,832	94,925	118,757	17,553	1,355	276	24,893	74,679	236,856	48,633
2018	42,838	25,824	24,031	96,994	121,026	17,885	1,382	278	25,370	76,111	312,967	45,059
2019	42,720	25,619	23,015	99,446	122,461	18,159	1,405	279	25,654	76,963	389,930	41,422
2020	38,026	22,813	20,951	90,185	111,136	17,961	1,433	281	22,865	68,596	458,527	33,563
2021	31,217	18,884	19,236	74,416	93,652	17,492	1,462	282	32,172	42,245	500,771	18,790
2022	25,722	15,804	18,923	60,884	79,807	17,149	1,491	284	33,486	27,398	528,169	11,079
2023	20,564	12,914	18,618	47,685	66,303	16,812	1,521	286	26,227	21,458	549,627	7,888
2024	21,355	13,370	19,263	50,803	70,066	17,425	1,551	287	27,942	22,861	572,489	7,640
2025	23,657	14,627	19,569	58,724	78,292	18,444	836	289	32,298	26,426	598,914	8,028
2026	21,072	13,182	19,635	52,212	71,848	18,492	852	291	28,717	23,496	622,410	6,489
2027												
Rem.												
Total	429,182	269,037	348,859	938,812	1,287,670	240,377	107,058	3,919	313,906	622,410		353,918

Orca Exploration Group Inc.

Table 4

Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Proved + Probable Reserves
Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Additional Gas Sales Only: Annual Volume MMcf	Additional Gas Sales Only: Avg Dar Gas Price US$/Mcf	Additional Gas Sales Only: Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	41.95	6.69	0.39	4.43	91.79	53.45	19,511	4.84	94,511	11,511	82,999
2014	6	38.34	42.85	7.36	0.47	5.31	94.32	55.99	20,435	4.92	100,445	12,057	88,388
2015	8	38.34	120.07	8.09	0.56	6.20	173.25	134.92	49,244	6.06	298,313	79,179	219,134
2016	8	38.34	118.53	8.90	0.67	6.82	173.25	134.92	49,244	6.17	303,901	79,179	224,723
2017	8	38.34	116.82	9.79	0.80	7.50	173.25	134.92	49,244	6.29	309,654	79,179	230,475
2018	8	38.34	115.95	10.00	0.96	8.00	173.25	134.92	49,244	6.40	315,240	79,179	236,062
2019	8	38.34	115.92	10.00	1.00	8.00	173.25	134.92	49,244	6.50	320,073	79,179	240,894
2020	8	38.34	115.92	10.00	1.00	8.00	173.25	134.92	49,244	6.60	324,898	79,179	245,719
2021	8	38.34	103.76	10.00	1.00	8.00	161.10	122.76	44,808	6.70	300,414	72,047	228,367
2022	8	38.34	83.74	10.00	1.00	8.00	141.08	102.74	37,502	6.83	255,973	60,298	195,675
2023	8	38.34	67.53	10.00	1.00	8.00	124.86	86.53	31,583	6.95	219,484	50,781	168,703
2024	8	22.36	67.98	10.00	1.00	8.00	109.35	86.98	31,749	7.06	224,029	51,048	172,980
2025	8	-	77.75	10.00	1.00	8.00	96.75	96.75	35,314	7.15	252,546	56,781	195,765
2026	8	-	60.30	10.00	1.00	8.00	79.30	79.30	28,943	7.29	210,974	46,537	164,437
2027													
Rem.													
Total		162,077	455,910	47,753	4,325	37,320	707,386	545,308	545,308	6.47	3,530,454	836,132	2,694,322

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,950	0.87	-	6,935	80	200	20,470	62,249	20,850	-	62,150
2014	17,952	0.88	-	79,204	82	200	88,958	66,291	66,291	22,666	22,097
2015	19,168	0.39	-	67,758	83	200	80,661	164,351	103,327	-	115,807
2016	19,743	0.40	-	7,158	85	200	25,443	168,542	25,443	-	199,280
2017	20,362	0.41	-	1,537	87	200	27,258	172,857	27,258	-	203,218
2018	20,895	0.42	-	1,568	88	200	27,641	177,046	27,641	-	208,421
2019	21,316	0.43	-	1,599	90	200	26,616	180,671	26,616	-	214,278
2020	21,722	0.44	-	1,631	92	200	24,898	184,289	24,898	-	220,821
2021	21,617	0.48	-	1,664	94	200	23,374	171,276	23,374	-	204,993
2022	21,152	0.56	-	1,697	96	200	22,944	146,756	22,944	-	172,730
2023	20,821	0.66	-	1,731	98	200	22,649	126,527	22,649	-	146,054
2024	21,426	0.67	-	1,766	99	200	23,291	129,735	23,291	-	149,689
2025	22,634	0.64	-	951	101	200	23,687	146,824	23,687	-	172,078
2026	22,308	0.77	-	970	103	200	23,382	123,328	23,382	-	141,055
2027											
Rem.											
Total	288,066	0.53	-	176,169	1,278	2,800	461,272		461,652		2,232,670

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,883	11,311	18,538	29,579	48,118	14,160	6,651	267	-	27,039	27,039	25,781
2014	18,226	15,807	57,531	10,839	68,371	15,580	71,523	271	-	(19,003)	8,037	(16,471)
2015	44,470	32,992	89,296	57,519	146,815	16,896	55,065	273	6,238	68,341	76,378	53,852
2016	44,470	26,648	22,628	98,978	121,607	17,404	6,310	275	24,404	73,213	149,591	52,446
2017	44,470	26,743	24,228	100,934	125,162	17,950	1,355	276	26,395	79,186	228,777	51,568
2018	44,275	26,597	24,432	103,065	127,497	18,318	1,374	277	26,882	80,645	309,423	47,744
2019	44,155	26,396	23,454	105,673	129,127	18,624	1,397	279	27,207	81,621	391,044	43,929
2020	44,155	26,224	21,953	108,900	130,853	18,978	1,425	280	27,542	82,627	473,670	40,427
2021	40,178	23,882	20,622	101,094	121,716	18,886	1,454	282	39,286	61,809	535,479	27,492
2022	33,626	20,206	20,246	85,183	105,429	18,480	1,483	284	46,851	38,332	573,811	15,500
2023	28,319	17,226	19,988	72,028	92,016	18,191	1,512	285	39,615	32,412	606,224	11,915
2024	28,468	17,321	20,549	73,820	94,370	18,720	1,543	287	40,601	33,219	639,443	11,101
2025	31,665	19,078	20,895	84,862	105,757	19,775	831	289	46,674	38,188	677,631	11,602
2026	25,952	15,875	20,628	69,562	90,191	19,490	848	290	38,259	31,303	708,934	8,645
2027												
Rem.												
Total	489,310	306,305	404,990	1,102,038	1,507,027	251,452	152,771	3,915	389,955	708,934		385,532

Orca Exploration Group Inc.

Table 5

Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life

Forecast of Production and Revenues

Proved Producing Reserves

Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Dar Gas Price US$/Mcf	Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	39.85	6.69	0.39	4.43	89.69	51.35	18,744	4.84	90,780	11,059	79,721
2014	6	38.34	40.30	7.36	0.47	5.31	91.77	53.44	19,505	4.91	95,840	11,508	84,332
2015	7	38.34	38.68	8.00	0.56	6.20	91.77	53.44	19,505	6.27	122,232	35,545	86,686
2016	7	38.34	37.95	8.00	0.67	6.82	91.77	53.44	19,505	6.32	123,325	35,545	87,780
2017	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.37	124,258	35,545	88,712
2018	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.46	126,066	35,545	90,521
2019	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.56	127,861	35,545	92,316
2020	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.65	129,713	35,545	94,167
2021	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.74	131,552	35,545	96,006
2022	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.85	133,519	35,545	97,974
2023	7	38.34	37.19	8.00	0.75	7.50	91.77	53.44	19,505	6.94	135,439	35,545	99,894
2024	7	22.36	53.16	8.00	0.75	7.50	91.77	69.41	25,335	7.07	179,058	46,170	132,888
2025	7	-	75.52	8.00	0.75	7.50	91.77	91.77	33,497	7.19	240,830	61,045	179,785
2026	7	-	75.52	8.00	0.75	7.50	91.77	91.77	33,497	7.30	244,409	61,045	183,365
2027	7	-	75.52	8.00	0.75	7.50	91.77	91.77	33,497	7.41	248,115	61,045	187,070
Rem.									201,572	8.04	1,621,583	367,340	1,254,243
Total		162,077	400,090	70,571	6,347	64,182	703,268	541,190	541,190		3,874,580	939,118	2,935,461

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,579	0.88	-	6,935	80	200	20,395	59,791	20,775	-	58,947
2014	17,485	0.90	-	39,164	82	200	54,548	63,249	54,548	-	29,784
2015	15,866	0.81	-	957	83	200	17,178	65,015	17,178	-	69,508
2016	16,232	0.83	-	976	85	200	17,570	65,835	17,570	-	70,210
2017	16,585	0.85	-	996	87	200	17,950	66,534	17,950	-	70,763
2018	16,907	0.87	-	1,016	88	200	18,012	67,890	18,012	-	72,509
2019	17,236	0.88	-	1,036	90	200	18,362	69,237	18,362	-	73,953
2020	17,572	0.90	-	1,057	92	200	18,720	70,626	18,720	-	75,447
2021	17,913	0.92	-	1,078	94	200	19,085	72,005	19,085	-	76,921
2022	18,263	0.94	-	1,099	96	200	19,458	73,480	19,458	-	78,516
2023	18,619	0.95	-	1,121	98	200	19,838	74,920	19,838	-	80,056
2024	19,966	0.79	-	1,144	99	200	21,209	99,666	21,209	-	111,679
2025	21,755	0.65	-	634	101	200	22,490	134,839	22,490	-	157,295
2026	22,174	0.66	-	647	103	200	22,924	137,524	22,924	-	160,441
2027	22,602	0.67	-	660	106	200	23,367	140,303	23,367	-	163,703
Rem.	293,952	1.46	59,741	9,879	1,581	-	365,152		312,498		941,745
Total	569,706	1.05	59,741	68,399	2,964	3,000	696,259		643,985		2,291,476

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,220	10,940	18,475	28,055	46,530	13,851	6,651	267	-	25,762	25,762	24,563
2014	17,585	15,624	52,785	14,769	67,554	15,382	39,051	272	-	12,849	38,611	11,137
2015	17,960	11,457	15,715	35,201	50,917	14,330	865	275	6,053	29,394	68,005	23,162
2016	17,960	11,471	16,069	35,557	51,626	14,660	882	277	8,952	26,855	94,860	19,238
2017	17,960	11,488	16,412	35,837	52,249	14,979	899	278	9,023	27,069	121,929	17,628
2018	17,960	11,461	16,468	36,721	53,189	15,271	917	280	9,180	27,541	149,470	16,305
2019	17,909	11,425	16,726	37,346	54,072	15,513	932	281	9,337	28,010	177,479	15,075
2020	17,909	11,423	17,048	38,101	55,149	15,815	951	283	9,525	28,576	206,055	13,981
2021	17,909	11,422	17,377	38,845	56,222	16,122	970	284	9,711	29,134	235,189	12,959
2022	17,909	11,420	17,712	39,650	57,363	16,437	990	286	9,913	29,738	264,927	12,025
2023	17,909	11,419	18,054	40,428	58,482	16,757	1,009	288	10,107	30,321	295,248	11,146
2024	23,262	14,429	19,288	56,398	75,686	17,969	1,030	290	14,099	42,298	337,546	14,135
2025	30,756	18,609	20,441	79,434	99,875	19,579	571	291	19,858	59,575	397,122	18,099
2026	30,756	18,607	20,832	81,023	101,854	19,956	582	293	20,256	60,767	457,889	16,783
2027	30,756	18,605	21,231	82,670	103,901	20,342	594	295	20,668	62,003	519,891	15,567
Rem.	181,879	115,010	281,448	437,967	719,415	318,323	8,891	1,623	108,192	282,387	802,278	52,058
Total	492,601	314,809	586,082	1,118,003	1,704,085	565,286	65,785	5,862	264,874	802,278		293,861

Orca Exploration Group Inc.

Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Total Proved Reserves
Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Additional Gas Sales Only: Annual Volume MMcf	Additional Gas Sales Only: Avg Dar Gas Price US$/Mcf	Additional Gas Sales Only: Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	39.47	6.69	0.39	4.43	89.31	50.97	18,605	4.84	90,107	10,977	79,130
2014	6	38.34	40.30	7.36	0.47	5.31	91.77	53.44	19,505	4.91	95,840	11,508	84,332
2015	8	38.34	115.21	8.00	0.56	6.20	168.30	129.97	47,437	6.27	297,332	86,449	210,884
2016	8	38.34	114.48	8.00	0.67	6.82	168.30	129.97	47,437	6.34	300,910	86,449	214,461
2017	8	38.34	113.72	8.00	0.75	7.50	168.30	129.97	47,437	6.42	304,376	86,449	217,927
2018	8	38.34	113.72	8.00	0.75	7.50	168.30	129.97	47,437	6.51	308,769	86,449	222,320
2019	8	38.34	113.72	8.00	0.75	7.50	168.30	129.97	47,437	6.60	313,199	86,449	226,751
2020	8	38.34	99.43	8.00	0.75	7.50	154.02	115.68	42,225	6.69	282,654	76,950	205,704
2021	8	38.34	78.72	8.00	0.75	7.50	133.31	94.97	34,664	6.78	235,086	63,172	171,915
2022	8	38.34	62.00	8.00	0.75	7.50	116.59	78.25	28,563	6.87	196,290	52,052	144,237
2023	8	38.34	46.31	8.00	0.75	7.50	100.90	62.56	22,835	6.96	158,854	41,613	117,241
2024	8	22.36	48.72	8.00	0.75	7.50	87.33	64.97	23,713	7.06	167,485	43,215	124,271
2025	8	-	55.72	8.00	0.75	7.50	71.97	71.97	26,269	7.18	188,483	47,873	140,610
2026	8	-	47.86	8.00	0.75	7.50	64.11	64.11	23,399	7.27	170,182	42,643	127,540
2027	8	-	40.36	8.00	0.75	7.50	56.61	56.61	20,661	7.37	152,339	37,652	114,687
Rem.									109,995	8.00	880,019	200,452	679,567
Total		162,077	486,108	60,928	5,443	55,142	769,698	607,621	607,621		4,141,926	1,060,351	3,081,576

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,524	0.89	-	6,935	80	200	20,381	59,347	20,761	-	58,369
2014	17,485	0.90	-	79,204	82	200	88,863	63,249	63,249	25,614	21,083
2015	19,091	0.40	-	10,536	83	200	23,362	158,163	48,977	-	161,907
2016	19,508	0.41	-	7,158	85	200	25,207	160,846	25,207	-	189,254
2017	19,913	0.42	-	1,537	87	200	26,809	163,446	26,809	-	191,119
2018	20,289	0.43	-	1,568	88	200	27,035	166,740	27,035	-	195,285
2019	20,672	0.44	-	1,599	90	200	25,972	170,063	25,972	-	200,778
2020	20,447	0.48	-	1,631	92	200	23,623	154,278	23,623	-	182,081
2021	19,913	0.57	-	1,664	94	200	21,670	128,936	21,670	-	150,245
2022	19,521	0.68	-	1,697	96	200	21,314	108,178	21,314	-	122,923
2023	19,138	0.84	-	1,731	98	200	20,967	87,931	20,967	-	96,274
2024	19,836	0.84	-	1,766	99	200	21,701	93,203	21,701	-	102,570
2025	20,996	0.80	-	951	101	200	22,049	105,458	22,049	-	118,562
2026	21,051	0.90	-	970	103	200	22,125	95,655	22,125	-	105,415
2027	21,120	1.02	-	990	106	200	22,215	86,015	22,215	-	92,472
Rem.	212,427	1.93	64,337	11,053	1,179	-	288,996		231,061		448,506
Total	507,931	0.84	64,337	130,989	2,562	3,000	702,288		644,733		2,436,843

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,100	10,873	18,464	27,780	46,244	13,805	6,651	267	-	25,521	25,521	24,334
2014	17,396	15,088	54,891	10,342	65,233	15,175	71,523	271	-	(21,735)	3,786	(18,840)
2015	42,838	28,439	46,009	80,416	126,425	16,829	9,288	273	11,123	88,913	92,698	70,062
2016	42,838	25,751	22,420	93,999	116,419	17,196	6,310	275	23,160	69,479	162,177	49,771
2017	42,838	25,850	23,832	94,925	118,757	17,553	1,355	276	24,893	74,679	236,856	48,633
2018	42,838	25,824	24,031	96,994	121,026	17,885	1,382	278	25,370	76,111	312,967	45,059
2019	42,720	25,619	23,015	99,446	122,461	18,159	1,405	279	25,654	76,963	389,930	41,422
2020	38,026	22,813	20,951	90,185	111,136	17,961	1,433	281	22,865	68,596	458,527	33,563
2021	31,217	18,884	19,236	74,416	93,652	17,492	1,462	282	32,172	42,245	500,771	18,790
2022	25,722	15,804	18,923	60,884	79,807	17,149	1,491	284	33,486	27,398	528,169	11,079
2023	20,564	12,914	18,618	47,685	66,303	16,812	1,521	286	26,227	21,458	549,627	7,888
2024	21,355	13,370	19,263	50,803	70,066	17,425	1,551	287	27,942	22,861	572,489	7,640
2025	23,657	14,627	19,569	58,724	78,292	18,444	836	289	32,298	26,426	598,914	8,028
2026	21,072	13,182	19,635	52,212	71,848	18,492	852	291	28,717	23,496	622,410	6,489
2027	18,606	11,803	19,715	45,801	65,516	18,553	869	293	25,191	20,611	643,021	5,175
Rem.	99,056	68,546	203,175	222,146	425,321	243,123	9,709	1,236	119,510	51,742	694,763	12,845
Total	546,844	349,386	571,749	1,206,759	1,778,508	502,053	117,636	5,448	458,607	694,763		371,938

Orca Exploration Group Inc.

Table 7

Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Proved + Probable Reserves
Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Additional Gas Sales Only: Annual Volume MMcf	Additional Gas Sales Only: Avg Dar Gas Price US$/Mcf	Additional Gas Sales Only: Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	41.95	6.69	0.39	4.43	91.79	53.45	19,511	4.84	94,511	11,511	82,999
2014	6	38.34	42.85	7.36	0.47	5.31	94.32	55.99	20,435	4.92	100,445	12,057	88,388
2015	8	38.34	120.07	8.09	0.56	6.20	173.25	134.92	49,244	6.06	298,313	79,179	219,134
2016	8	38.34	118.53	8.90	0.67	6.82	173.25	134.92	49,244	6.17	303,901	79,179	224,723
2017	8	38.34	116.82	9.79	0.80	7.50	173.25	134.92	49,244	6.29	309,654	79,179	230,475
2018	8	38.34	115.95	10.00	0.96	8.00	173.25	134.92	49,244	6.40	315,240	79,179	236,062
2019	8	38.34	115.92	10.00	1.00	8.00	173.25	134.92	49,244	6.50	320,073	79,179	240,894
2020	8	38.34	115.92	10.00	1.00	8.00	173.25	134.92	49,244	6.60	324,898	79,179	245,719
2021	8	38.34	103.76	10.00	1.00	8.00	161.10	122.76	44,808	6.70	300,414	72,047	228,367
2022	8	38.34	83.74	10.00	1.00	8.00	141.08	102.74	37,502	6.83	255,973	60,298	195,675
2023	8	38.34	67.53	10.00	1.00	8.00	124.86	86.53	31,583	6.95	219,484	50,781	168,703
2024	8	22.36	67.98	10.00	1.00	8.00	109.35	86.98	31,749	7.06	224,029	51,048	172,980
2025	8	-	77.75	10.00	1.00	8.00	96.75	96.75	35,314	7.15	252,546	56,781	195,765
2026	8	-	60.30	10.00	1.00	8.00	79.30	79.30	28,943	7.29	210,974	46,537	164,437
2027	8	-	53.40	10.00	1.00	8.00	72.40	72.40	26,427	7.42	196,074	42,491	153,583
Rem.									161,974	8.22	1,331,704	260,435	1,071,269
Total		162,077	580,265	81,461	7,696	64,287	895,786	733,709	733,709		5,058,232	1,139,058	3,919,174

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,950	0.87	-	6,935	80	200	20,470	62,249	20,850	-	62,150
2014	17,952	0.88	-	79,204	82	200	88,958	66,291	66,291	22,666	22,097
2015	19,168	0.39	-	67,758	83	200	80,661	164,351	103,327	-	115,807
2016	19,743	0.40	-	7,158	85	200	25,443	168,542	25,443	-	199,280
2017	20,362	0.41	-	1,537	87	200	27,258	172,857	27,258	-	203,218
2018	20,895	0.42	-	1,568	88	200	27,641	177,046	27,641	-	208,421
2019	21,316	0.43	-	1,599	90	200	26,616	180,671	26,616	-	214,278
2020	21,722	0.44	-	1,631	92	200	24,898	184,289	24,898	-	220,821
2021	21,617	0.48	-	1,664	94	200	23,374	171,276	23,374	-	204,993
2022	21,152	0.56	-	1,697	96	200	22,944	146,756	22,944	-	172,730
2023	20,821	0.66	-	1,731	98	200	22,649	126,527	22,649	-	146,054
2024	21,426	0.67	-	1,766	99	200	23,291	129,735	23,291	-	149,689
2025	22,634	0.64	-	951	101	200	23,687	146,824	23,687	-	172,078
2026	22,308	0.77	-	970	103	200	23,382	123,328	23,382	-	141,055
2027	22,436	0.85	-	990	106	200	23,531	115,187	23,531	-	130,052
Rem.	271,915	1.68	75,304	13,538	1,444	-	362,201		300,121		771,148
Total	582,417	0.79	75,304	190,697	2,828	3,000	847,004		785,304		3,133,870

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,883	11,311	18,538	29,579	48,118	14,160	6,651	267	-	27,039	27,039	25,781
2014	18,226	15,807	57,531	10,839	68,371	15,580	71,523	271	-	(19,003)	8,037	(16,471)
2015	44,470	32,992	89,296	57,519	146,815	16,896	55,065	273	6,238	68,341	76,378	53,852
2016	44,470	26,648	22,628	98,978	121,607	17,404	6,310	275	24,404	73,213	149,591	52,446
2017	44,470	26,743	24,228	100,934	125,162	17,950	1,355	276	26,395	79,186	228,777	51,568
2018	44,275	26,597	24,432	103,065	127,497	18,318	1,374	277	26,882	80,645	309,423	47,744
2019	44,155	26,396	23,454	105,673	129,127	18,624	1,397	279	27,207	81,621	391,044	43,929
2020	44,155	26,224	21,953	108,900	130,853	18,978	1,425	280	27,542	82,627	473,670	40,427
2021	40,178	23,882	20,622	101,094	121,716	18,886	1,454	282	39,286	61,809	535,479	27,492
2022	33,626	20,206	20,246	85,183	105,429	18,480	1,483	284	46,851	38,332	573,811	15,500
2023	28,319	17,226	19,988	72,028	92,016	18,191	1,512	285	39,615	32,412	606,224	11,915
2024	28,468	17,321	20,549	73,820	94,370	18,720	1,543	287	40,601	33,219	639,443	11,101
2025	31,665	19,078	20,895	84,862	105,757	19,775	831	289	46,674	38,188	677,631	11,602
2026	25,952	15,875	20,628	69,562	90,191	19,490	848	290	38,259	31,303	708,934	8,645
2027	23,695	14,608	20,759	64,136	84,895	19,602	865	292	35,275	28,861	737,795	7,246
Rem.	145,234	96,691	262,411	380,298	642,708	303,360	11,828	1,462	205,759	120,300	858,095	24,006
Total	658,239	417,603	688,159	1,546,471	2,234,631	574,414	165,463	5,669	630,989	858,095		416,785

Orca Exploration Group Inc.

Table 8

Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Proved + Probable + Possible Reserves
Forecast Price Case as of December 31, 2012

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Additional Gas Sales Only: Annual Volume MMcf	Additional Gas Sales Only: Avg Dar Gas Price US$/Mcf	Additional Gas Sales Only: Dar Sales Revenue US$M	Transp. Costs US$M	Field Net Sales Revenue US$M
2013	4	38.34	41.95	6.69	0.39	4.43	91.79	53.45	19,511	4.84	94,511	11,511	82,999
2014	6	38.34	42.85	7.36	0.47	5.31	94.32	55.99	20,435	4.92	100,445	12,057	88,388
2015	8	38.34	125.02	8.09	0.56	6.20	178.20	139.87	51,051	5.89	300,566	73,398	227,168
2016	8	38.34	123.48	8.90	0.67	6.82	178.20	139.87	51,051	6.00	306,314	73,398	232,917
2017	9	38.34	121.77	9.79	0.80	7.50	178.20	139.87	51,051	6.12	312,231	73,398	238,833
2018	9	38.34	119.88	10.77	0.96	8.25	178.20	139.87	51,051	6.26	319,684	73,398	246,286
2019	9	38.34	118.36	11.85	1.16	8.50	178.20	139.87	51,051	6.42	327,741	73,398	254,344
2020	9	38.34	118.12	12.00	1.25	8.50	178.20	139.87	51,051	6.53	333,545	73,398	260,147
2021	9	38.34	118.12	12.00	1.25	8.50	178.20	139.87	51,051	6.63	338,680	73,398	265,283
2022	9	38.34	115.26	12.00	1.25	8.50	175.35	137.01	50,009	6.74	337,242	71,901	265,341
2023	9	38.34	95.36	12.00	1.25	8.50	155.44	117.11	42,744	6.88	294,192	61,455	232,738
2024	9	22.36	95.05	12.00	1.25	8.50	139.16	116.80	42,631	6.99	298,108	61,292	236,816
2025	9	-	101.61	12.00	1.25	8.50	123.36	123.36	45,028	7.09	319,284	64,739	254,545
2026	9	-	88.68	12.00	1.25	8.50	110.43	110.43	40,308	7.23	291,467	57,952	233,515
2027	9	-	77.12	12.00	1.25	8.50	98.87	98.87	36,087	7.38	266,325	51,883	214,442
Rem.									253,719	8.48	2,151,171	364,783	1,786,388
Total		162,077	714,395	107,957	10,660	74,814	1,069,904	907,827	907,827		6,391,507	1,271,358	5,120,149

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2013	16,950	0.87	-	6,935	80	200	20,470	62,249	20,850	-	62,150
2014	17,952	0.88	-	79,204	82	200	88,958	66,291	66,291	22,666	22,097
2015	19,246	0.38	-	67,758	83	200	80,739	170,376	103,405	-	123,762
2016	19,824	0.39	-	7,158	85	200	25,524	174,687	25,524	-	207,393
2017	20,523	0.40	-	61,071	87	200	86,952	179,125	86,952	-	151,881
2018	21,213	0.42	-	1,568	88	200	27,959	184,714	27,959	-	218,327
2019	21,966	0.43	-	1,599	90	200	27,266	190,758	27,266	-	227,078
2020	22,481	0.44	-	1,631	92	200	25,657	195,110	25,657	-	234,490
2021	22,910	0.45	-	1,664	94	200	24,668	198,962	24,668	-	240,615
2022	23,229	0.46	-	1,697	96	200	25,022	199,006	25,022	-	240,319
2023	22,809	0.53	-	1,731	98	200	24,637	174,553	24,637	-	208,101
2024	23,399	0.55	-	1,766	99	200	25,264	177,612	25,264	-	211,551
2025	24,440	0.54	-	951	101	200	25,492	190,909	25,492	-	229,053
2026	24,356	0.60	-	970	103	200	25,429	175,136	25,429	-	208,086
2027	24,323	0.67	-	990	106	200	25,418	160,831	25,418	-	189,023
Rem.	393,703	1.55	90,568	18,815	2,007	-	505,093		429,029		1,357,358
Total	719,323	0.79	90,568	255,507	3,390	3,000	1,064,548		988,864		4,131,285

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee & Training Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2013	16,883	11,311	18,538	29,579	48,118	14,160	6,651	267	-	27,039	27,039	25,781
2014	18,226	15,807	57,531	10,839	68,371	15,580	71,523	271	-	(19,003)	8,037	(16,471)
2015	46,102	33,897	89,365	61,470	150,835	16,965	55,065	273	7,226	71,305	79,341	56,187
2016	46,102	27,553	22,700	103,008	125,708	17,475	6,310	275	25,412	76,236	155,577	54,611
2017	46,102	31,514	71,997	75,436	147,433	18,091	48,982	276	20,021	60,063	215,640	39,115
2018	45,900	27,501	24,711	107,964	132,675	18,597	1,374	277	28,106	84,319	299,959	49,919
2019	45,655	27,224	23,943	111,692	135,636	19,128	1,393	278	28,709	86,128	386,087	46,354
2020	45,655	27,057	22,543	115,338	137,881	19,577	1,420	280	29,151	87,453	473,540	42,789
2021	45,655	26,948	21,681	118,351	140,032	19,951	1,449	282	45,309	73,042	546,581	32,489
2022	44,724	26,423	21,990	118,205	140,195	20,229	1,478	283	65,013	53,192	599,773	21,509
2023	38,226	22,776	21,654	102,358	124,012	19,862	1,507	285	56,297	46,061	645,834	16,932
2024	38,125	22,728	22,201	104,055	126,256	20,376	1,538	287	57,230	46,825	692,659	15,648
2025	40,269	23,892	22,399	112,664	135,063	21,282	828	288	61,965	50,699	743,358	15,402
2026	36,047	21,524	22,344	102,351	124,695	21,209	845	290	56,293	46,058	789,416	12,720
2027	32,273	19,404	22,335	92,974	115,309	21,181	862	292	51,136	41,838	831,254	10,505
Rem.	226,902	146,917	373,806	667,641	1,041,447	421,712	16,384	1,948	363,484	237,919	1,069,174	41,426
Total	812,844	512,476	859,737	2,033,927	2,893,664	705,376	217,609	6,153	895,353	1,069,174		464,916

Orca Exploration Group Inc.

Table 9

Songo Songo Field Tanzania - Total Protected and Additional Volumes
Natural Gas Reserve Summary

Effective December 31, 2012

	Cenomanian	Neocom. North Units 10-6	Neocom. Main Units 10-6	Neocom. Main Unit 5	Neocom. Main Unit 4-1	Total
Gross Rock Volume, Ac-ft	326,172	385,788	1,258,981	285,715	132,946	2,389,602
Net to Gross Ratio, frac.	0.211	0.84	0.84	0.59	0.88	
Porosity, %	21.0	20.0	20.0	18.0	19.0	
Water Saturation, %	34.0	28.0	28.0	36.0	28.0	
Reservoir Pressure, psia	2,770	2,770	2,770	2,770	2,770	
Reservoir Temperature, deg F	203	203	203	203	203	
Compressibility Factor	0.93	0.93	0.93	0.93	0.93	
Original Gas-in-Place, Bcf	66.5	325.4	1,061.8	135.4	111.6	1,700.6
Proved Producing Reserves						
Portion of Mapped OGIP Classified as Proved, %	50	-	100	100	100	
Original Gas-in-Place, Bcf	33.3	-	1,061.8	135.4	111.6	1,342.0
Recovery Factor, %	67.5	-	67.5	67.5	67.5	67.5
Original Recoverable Raw, Bcf	22.4	-	716.7	91.4	75.3	905.9
Cumulative Recovery, Bcf						195.5
Remaining Recoverable Raw, Bcf						710.4
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						703.3
Total Proved Reserves						
Portion of Mapped OGIP Classified as Proved, %	50	-	100	100	100	
Original Gas-in-Place, Bcf	33.3	-	1,061.8	135.4	111.6	1,342.0
Recovery Factor, %	72.5	-	72.5	72.5	72.5	72.5
Original Recoverable Raw, Bcf	24.1	-	769.8	98.2	80.9	973.0
Cumulative Recovery, Bcf						195.5
Remaining Recoverable Raw, Bcf						777.5
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						769.7
Proved Non-Producing Reserves, Bcf						66.4
Proved + Probable Reserves						
Portion of Mapped OGIP Classified as 2P, %	75	50	100	100	100	
Original Gas-in-Place, Bcf	49.9	162.7	1,061.8	135.4	111.6	1,521.3
Recovery Factor, %	75.0	50.0	75.0	75.0	75.0	72.3
Original Recoverable Raw, Bcf	37.4	81.3	796.3	101.5	83.7	1,100.3
Cumulative Recovery, Bcf						195.5
Remaining Recoverable Raw, Bcf						904.8
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						895.8
Probable Reserves, Bcf						126.1
Proved + Probable + Possible Reserves						
Portion of Mapped OGIP Classified as 3P, %	125	100	100	100	100	
Original Gas-in-Place, Bcf	83.1	325.4	1,061.8	135.4	111.6	1,717.3
Recovery Factor, %	80.0	50.0	80.0	80.0	80.0	74.3
Original Recoverable Raw, Bcf	66.5	162.7	849.4	108.3	89.3	1,276.2
Cumulative Recovery, Bcf						195.5
Remaining Recoverable Raw, Bcf						1,080.7
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						1,069.9
Possible Reserves, Bcf						174.1
Reserves Summary, Sales Bcf						
Protected Volumes						
Proved						162.1
Proved Plus Probable						162.1
Proved Plus Probable Plus Possible						162.1
Additional Volumes						
Proved						607.6
Proved Plus Probable						733.7
Proved Plus Probable Plus Possible						907.8

Note - This table above includes protected and additional gas volumes to end of field life

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Reservoir and Fluid Properties
Effective December 31, 2012

Table 10

Zone	**Cenomanian & Neocomian**
Lithology	Sandstone
Pool Area of N1 Layer, acres	6,090
Depth to Top of Structure, ft	5,450
Depth to Gas Water Contact, ft	6,364
Maximum Gross Gas Pay Thickness (from structure map), ft	914
Average Gross Pay, ft	540
Permeability, md	10 to 40 md
Condensate Gas Ratio, bbl/mmcf	0.1 to 0.2
Gross Heating Value, BTU/scf	1,023

Orca Exploration Group Inc.
Songo Songo Field - Tanzania
Summary of Economic Parameters
Effective December 31, 2012

Price Schedule

McDaniel & Associates December 31, 2012 forecast price case

Natural Gas Price Forecast (2013$ - US)

See Table 16

Operating Costs (2013$ - US - Orca Estimates)

	Reserves Case			
Processing and Pipeline Fee, $/Mcf	**PP**	**1P**	**2P**	**3P**
2013-2014	0.59	0.59	0.59	0.59
2015+	0.59	1.82	1.61	1.44

Field Operating Expenses	**Amount**
Wells and Gathering System, $/Year **	715,000
Wells and Gathering System, $/Well-Year **	90,000
Wells and Gathering System, $/Mcf **	0.021
Dar Gas Distribution System, $/Year	1,000,000
Dar Gas Distribution System, $/Mcf (Industrial Sales)	0.420
CNG Distribution System, $/Year	220,000
CNG Distribution System, $/Mcf (CNG Sales)	1.52
Regulator Fee, % of Additional Sales Gross Revenue	1.0%
Municipal Fee, % of Additional Sales Gross Revenue	0.3%
Re-Rating Fee, $/Mcf 70 to 90 MMcfpd	0.30
Re-Rating Fee, $/Mcf > 90 MMcfpd	0.40
G&A (Excluding head office G&A)	9,774,000

** Split between protected and additional volumes according to rates.

Capital Costs (2013$ - US)

Year	Gross Amount		Description
Proved Producing Case			
2013	$420,000		Miscellaneous field costs
2013	$1,305,000		Miscellaneous downstream costs
2013	$4,500,000		SS-10 Dedicated flowline
2013	$710,000		SS-11 to SS-3 Jumper
2014	$2,476,000		SS-11 to SS-3 Jumper
2014	$27,000,000		Workover SS-5 & SS-9
2014	$8,000,000		Workover SS-3 & SS-4
2014 - 2024	$420,000	/year	Miscellaneous field costs
2025+	$250,000	/year	Miscellaneous field costs
2014 - 2024	$500,000	/year	Miscellaneous downstream costs
2025+	$250,000	/year	Miscellaneous downstream costs
Proved Undeveloped			
2014	$32,739,000		Drill & tie-in SS-12 Well
2014	$5,781,000		Chinese gas plant costs
2014	$735,000		Miscellaneous downstream costs
2015	$9,207,000		Miscellaneous downstream costs
2016	$5,825,000		Miscellaneous downstream costs
2017 - 2023	$500,000	/year	Miscellaneous downstream costs
2024+	$250,000	/year	Miscellaneous downstream costs
Probable			
2015	$55,000,000		Drill SSN Well
Possible			
2017	$55,000,000		Drill SSN Well

See Tables 12 to 15

Abandonment Costs (2013$ - US)

Well Abandonments — $5,000,000 per well at the end of the forecast

Orca Exploration Group Inc.
Songo Songo Field - Tanzania
Summary of Economic Parameters
Effective December 31, 2012

Interests and Fiscal Terms (2012$ - US)

Orca Interest	100 percent prior to TPDC back in
TPDC Back-in	TPDC is entitled to pay from 5 to 20 percent of the cost of new wells to earn a 5 to 20 percent interest in the production from those wells. It was assumed that TPDC would exercise the option for 20 percent on all new wells and that all future expenses would be shared according to the weighted average interest from all wells.
Cost Recovery Balance @ 2012/12/31	$380,000
State Royalty	Nil
Eligible Costs for Cost Recovery	Operating costs, G&A, workover costs, remaining capital costs, training fund, DMO, financing costs (of cost recovery balance)
Cost Recovery Limit	75 percent of net sales revenue
Profit Revenues	Net sales revenues less Cost Revenues
Contractor share of Profit Revenues	Greater of the cum. production based calc. or rate based calc. Cumulative Production Based Calculation: 0 - 125 Bcf / 25 percent share 125 - 250 Bcf / 30 percent share 250 - 375 Bcf / 35 percent share 375 - 500 Bcf / 40 percent share 500 + Bcf / 55 percent share Rate Based Calculation 0 - 20 MMcf/d / 25 percent share 20 - 30 MMcf/d / 30 percent share 30 - 40 MMcf/d / 35 percent share 40 - 50 MMcf/d / 40 percent share 50+ MMcf/d / 55 percent share
Training Fund	$80,000 / Year
Bonuses	Nil
Hydrocarbon Support Fund	Nil
TPDC Marketing Fee	$200,000/year
Additional Profits Tax	25 percent APT on First Account cash flow balance after allowance for a 25% rate (plus inflation) of return on negative balances. 40 percent APT on Second Account cash flow balance after allowance for a 35% rate (plus inflation) of return on negative balances.
First Account Opening Balance	$45,846,000 at December 31, 2012
Second Account Opening Balance	$134,604,000 at December 31, 2012
License Expiry	October 11, 2026

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Proved Producing Reserves

Table 12

Forecast Price Case as of December 31, 2012

Year	New Wells #	New Wells 2013 US$M	Workovers 2013 US$M	Facility & Downstream 2013 US$M	Field Maint. 2013 US$M	Total Capital 2013 US$M	Total Capital Future $M
2013	-	-	5,210	1,305	420	6,935	6,935
2014	-	-	37,476	500	420	38,396	39,164
2015	-	-	-	500	420	920	957
2016	-	-	-	500	420	920	976
2017	-	-	-	500	420	920	996
2018	-	-	-	500	420	920	1,016
2019	-	-	-	500	420	920	1,036
2020	-	-	-	500	420	920	1,057
2021	-	-	-	500	420	920	1,078
2022	-	-	-	500	420	920	1,099
2023	-	-	-	500	420	920	1,121
2024	-	-	-	500	420	920	1,144
2025	-	-	-	250	250	500	634
2026	-	-	-	250	250	500	647
2027	-	-	-	250	250	500	660
2028	-	-	-	250	250	500	673
2029	-	-	-	250	250	500	686
2030	-	-	-	250	250	500	700
2031	-	-	-	250	250	500	714
2032	-	-	-	250	250	500	728
2033	-	-	-	250	250	500	743
2034	-	-	-	250	250	500	758
2035	-	-	-	250	250	500	773
2036	-	-	-	250	250	500	788
2037	-	-	-	250	250	500	804
2038	-	-	-	250	250	500	820
2039	-	-	-	250	250	500	837
2040	-	-	-	250	250	500	853
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
Total	-	-	42,686	10,805	9,040	62,531	68,399

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Total Proved Reserves
Forecast Price Case as of December 31, 2012

	New Wells		Flowlines & Workovers	Facility & Downstream	Field Maint.	Total Capital	Total Capital
Year	#	2013 US$M	2013 US$M	2013 US$M	2013 US$M	2013 US$M	Future $M
2013	-	-	5,210	1,305	420	6,935	6,935
2014	1	32,739	37,476	7,016	420	77,651	79,204
2015	-	-	-	9,707	420	10,127	10,536
2016	-	-	-	6,325	420	6,745	7,158
2017	-	-	-	1,000	420	1,420	1,537
2018	-	-	-	1,000	420	1,420	1,568
2019	-	-	-	1,000	420	1,420	1,599
2020	-	-	-	1,000	420	1,420	1,631
2021	-	-	-	1,000	420	1,420	1,664
2022	-	-	-	1,000	420	1,420	1,697
2023	-	-	-	1,000	420	1,420	1,731
2024	-	-	-	1,000	420	1,420	1,766
2025	-	-	-	500	250	750	951
2026	-	-	-	500	250	750	970
2027	-	-	-	500	250	750	990
2028	-	-	-	500	250	750	1,009
2029	-	-	-	500	250	750	1,030
2030	-	-	-	500	250	750	1,050
2031	-	-	-	500	250	750	1,071
2032	-	-	-	500	250	750	1,093
2033	-	-	-	500	250	750	1,114
2034	-	-	-	500	250	750	1,137
2035	-	-	-	500	250	750	1,159
2036	-	-	-	500	250	750	1,183
2037	-	-	-	500	250	750	1,206
2038	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
Total	1	32,739	42,686	38,853	8,290	122,568	130,989

Orca Exploration Group Inc.

Table 14

Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Proved Plus Probable Reserves

Forecast Price Case as of December 31, 2012

Year	New Wells #	New Wells 2013 US$M	Workovers 2013 US$M	Facility & Downstream 2013 US$M	Field Maint. 2013 US$M	Total Capital 2013 US$M	Total Capital Future $M
2013	-	-	5,210	1,305	420	6,935	6,935
2014	1	32,739	37,476	7,016	420	77,651	79,204
2015	1	55,000	-	9,707	420	65,127	67,758
2016	-	-	-	6,325	420	6,745	7,158
2017	-	-	-	1,000	420	1,420	1,537
2018	-	-	-	1,000	420	1,420	1,568
2019	-	-	-	1,000	420	1,420	1,599
2020	-	-	-	1,000	420	1,420	1,631
2021	-	-	-	1,000	420	1,420	1,664
2022	-	-	-	1,000	420	1,420	1,697
2023	-	-	-	1,000	420	1,420	1,731
2024	-	-	-	1,000	420	1,420	1,766
2025	-	-	-	500	250	750	951
2026	-	-	-	500	250	750	970
2027	-	-	-	500	250	750	990
2028	-	-	-	500	250	750	1,009
2029	-	-	-	500	250	750	1,030
2030	-	-	-	500	250	750	1,050
2031	-	-	-	500	250	750	1,071
2032	-	-	-	500	250	750	1,093
2033	-	-	-	500	250	750	1,114
2034	-	-	-	500	250	750	1,137
2035	-	-	-	500	250	750	1,159
2036	-	-	-	500	250	750	1,183
2037	-	-	-	500	250	750	1,206
2038	-	-	-	500	250	750	1,230
2039	-	-	-	500	250	750	1,255
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
Total	2	87,739	42,686	39,853	8,790	179,068	190,697

Orca Exploration Group Inc.

Table 15

Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Proved + Probable + Possible Reserves

Forecast Price Case as of December 31, 2012

Year	New Wells #	New Wells 2013 US$M	Workovers 2013 US$M	Facility & Downstream 2013 US$M	Field Maint. 2013 US$M	Total Capital 2013 US$M	Total Capital Future $M
2013	-	-	5,210	1,305	420	6,935	6,935
2014	1	32,739	37,476	7,016	420	77,651	79,204
2015	1	55,000	-	9,707	420	65,127	67,758
2016	-	-	-	6,325	420	6,745	7,158
2017	1	55,000	-	1,000	420	56,420	61,071
2018	-	-	-	1,000	420	1,420	1,568
2019	-	-	-	1,000	420	1,420	1,599
2020	-	-	-	1,000	420	1,420	1,631
2021	-	-	-	1,000	420	1,420	1,664
2022	-	-	-	1,000	420	1,420	1,697
2023	-	-	-	1,000	420	1,420	1,731
2024	-	-	-	1,000	420	1,420	1,766
2025	-	-	-	500	250	750	951
2026	-	-	-	500	250	750	970
2027	-	-	-	500	250	750	990
2028	-	-	-	500	250	750	1,009
2029	-	-	-	500	250	750	1,030
2030	-	-	-	500	250	750	1,050
2031	-	-	-	500	250	750	1,071
2032	-	-	-	500	250	750	1,093
2033	-	-	-	500	250	750	1,114
2034	-	-	-	500	250	750	1,137
2035	-	-	-	500	250	750	1,159
2036	-	-	-	500	250	750	1,183
2037	-	-	-	500	250	750	1,206
2038	-	-	-	500	250	750	1,230
2039	-	-	-	500	250	750	1,255
2040	-	-	-	500	250	750	1,280
2041	-	-	-	500	250	750	1,306
2042	-	-	-	500	250	750	1,332
2043	-	-	-	500	250	750	1,359
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
Total	3	142,739	42,686	41,853	9,790	237,068	255,507

McDaniel & Associates Consultants Ltd.
Summary of Price Forecasts
Effective December 31, 2012

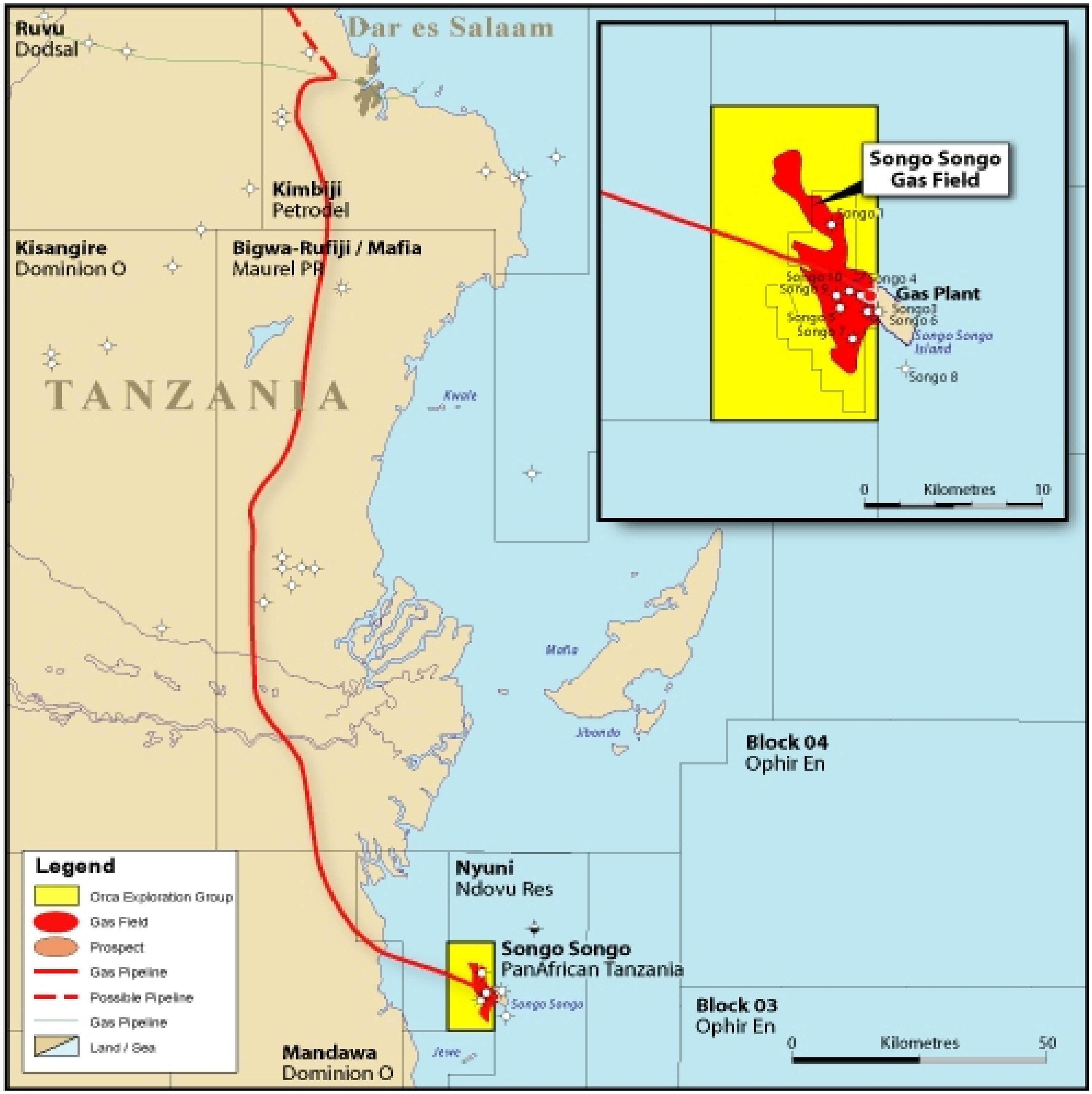
Table 16

Year	Brent Crude Oil Price $US/bbl	UGTG & Power Base Gas Price $US/MMBTU	UGTG & Power Excess Gas Price $US/MMBTU	Industrial Gas Price $US/MMBTU	Compressed Natural Gas Price $US/MMBTU	Wazo Hill Gas Price $US/MMBTU	Inflation %
2013	107.50	2.79	4.18	11.29	15.05	3.60	2.0
2014	102.50	2.84	4.27	10.76	14.35	3.67	2.0
2015	101.40	2.90	4.35	10.65	14.20	3.74	2.0
2016	100.80	2.96	4.44	10.58	14.11	3.82	2.0
2017	100.10	3.02	4.53	10.51	14.01	3.89	2.0
2018	102.20	3.08	4.62	10.73	14.31	3.97	2.0
2019	104.20	3.14	4.71	10.94	14.59	4.05	2.0
2020	106.30	3.20	4.80	11.16	14.88	4.13	2.0
2021	108.30	3.27	4.90	11.37	15.16	4.22	2.0
2022	110.60	3.33	5.00	11.61	15.48	4.30	2.0
2023	112.70	3.40	5.10	11.83	15.78	4.39	2.0
2024	115.00	3.47	5.20	12.08	16.10	4.47	2.0
2025	117.30	3.54	5.30	12.32	16.42	4.56	2.0
2026	119.60	3.61	5.41	12.56	16.74	4.65	2.0
2027	122.10	3.68	5.52	12.82	17.09	4.75	2.0
2028	124.50	3.75	5.63	13.07	17.43	4.84	2.0
2029	127.00	3.83	5.74	13.34	17.78	4.94	2.0
2030	129.50	3.90	5.86	13.60	18.13	5.04	2.0
2031	132.10	3.98	5.97	13.87	18.49	5.14	2.0
2032	134.70	4.06	6.09	14.14	18.86	5.24	2.0
Thereafter	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Pricing Assumptions :

Above prices are referenced at the inlet to the Songo Songo gas plant
Brent price forecast based on the McDaniel & Associates December 31, 2012 price forecast
Gas price for power market sales based on $2.50/MMbtu in 2008$ plus inflation.
Base gas price is for volumes up to 36.8 MMBtu/day
Excess gas price is 150 percent of the base price and is based on volumes above 36.8 MMBtu/day
Gas price for industrial sales based on historical relationship to Brent.
Gas price for CNG sales based on historical relationship to Brent.
Gas price for Wazo Hill sales based on $3.08/GJ in 2008$ plus 2% inflation
All prices are adjusted for a heating value of 1022 btu/scf.

Figure 1



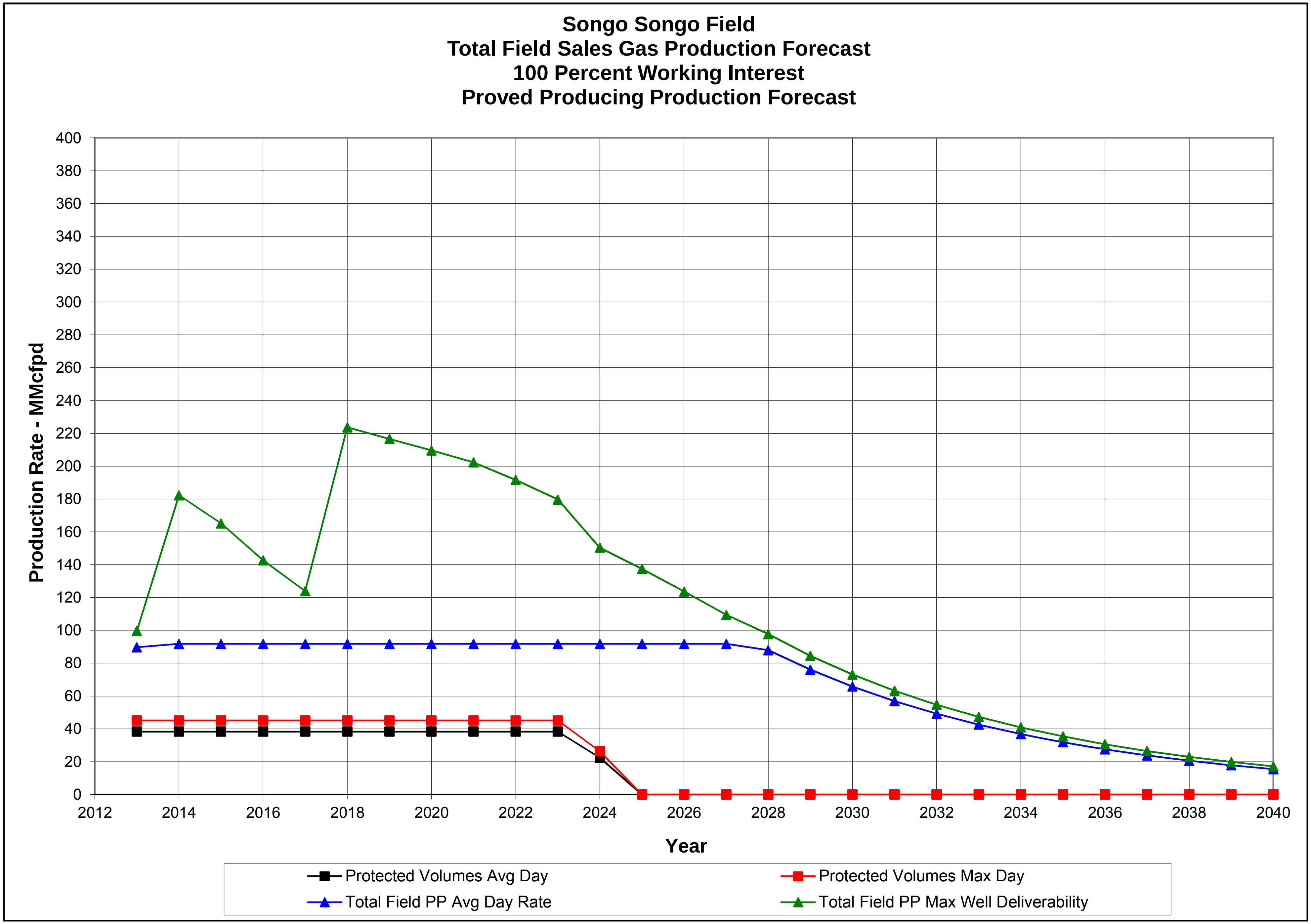
McDaniel & Associates Consultants Ltd.

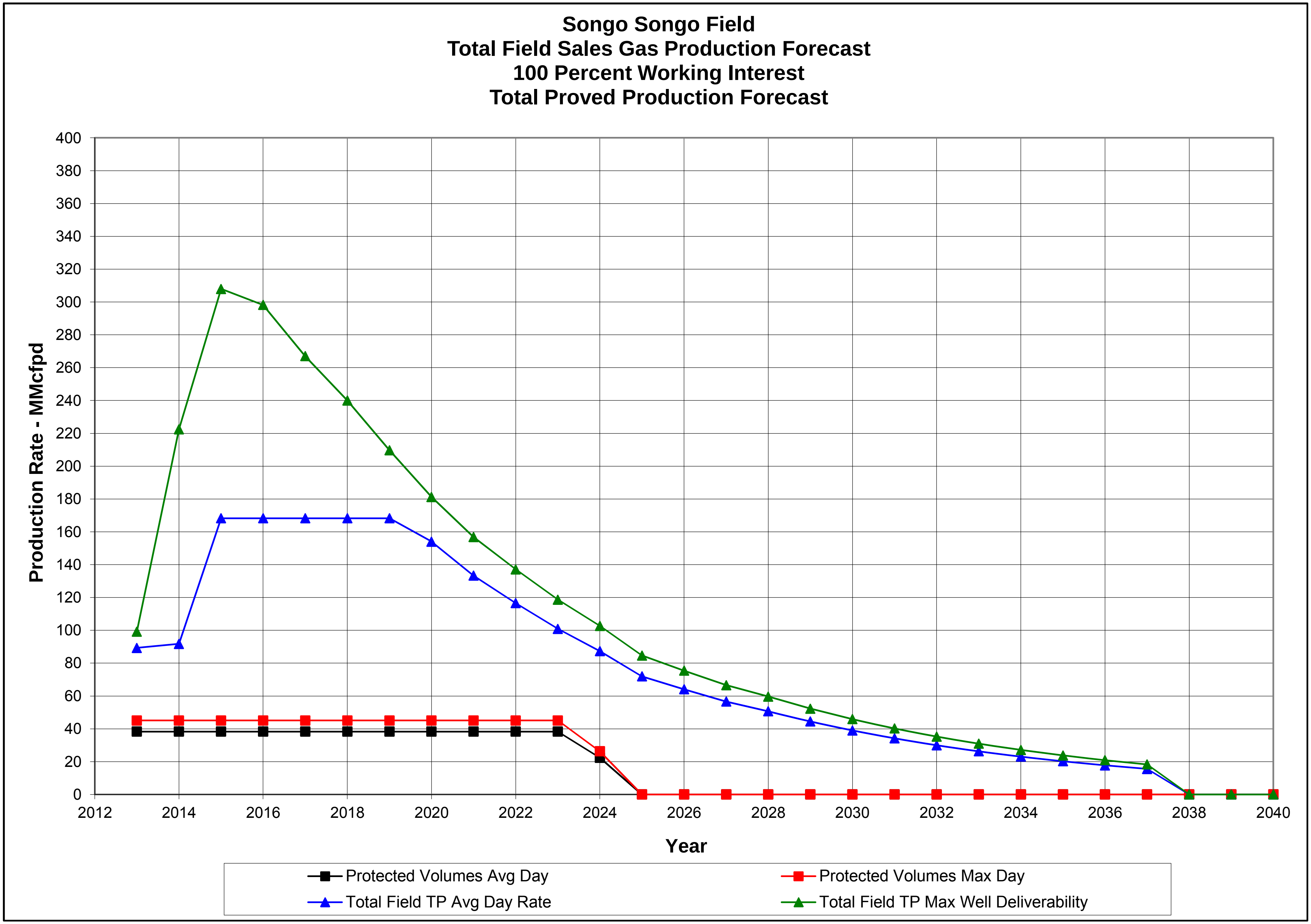
Orca Exploration

Songo Songo field - Tanzania

Location Map

Figure 2


Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Proved Producing Production Forecast
Production Rate - MMcfpd
Year
400
380
360
340
320
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Protected Volumes Avg Day
Protected Volumes Max Day
Total Field PP Avg Day Rate
Total Field PP Max Well Deliverability


Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Total Proved Production Forecast
Production Rate - MMcfpd
Year
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
320
340
360
380
400
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Protected Volumes Avg Day
Protected Volumes Max Day
Total Field TP Avg Day Rate
Total Field TP Max Well Deliverability

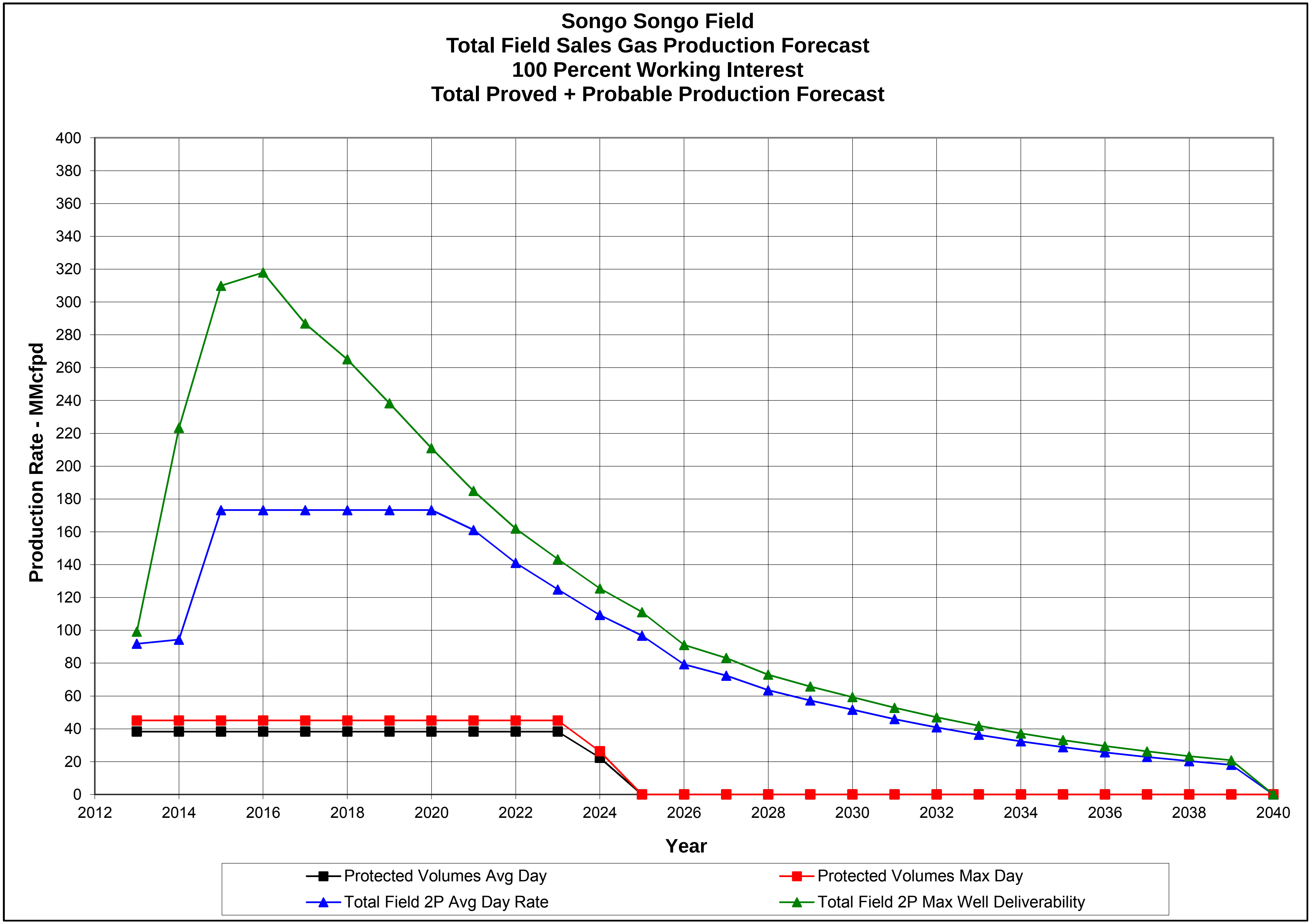
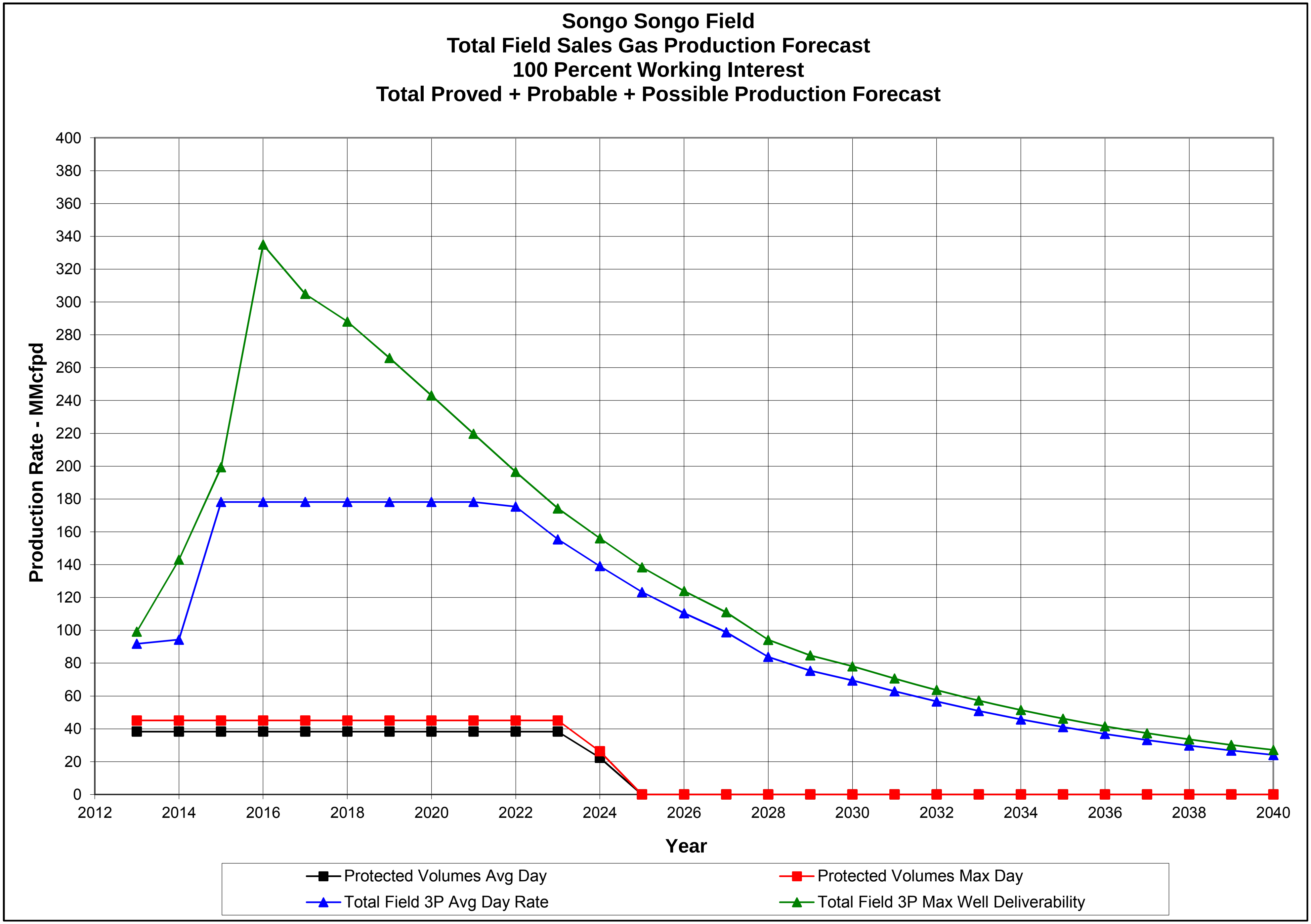

Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Total Proved + Probable Production Forecast
Production Rate - MMcfpd
400
380
360
340
320
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
Protected Volumes Avg Day
Protected Volumes Max Day
Total Field 2P Avg Day Rate
Total Field 2P Max Well Deliverability

Figure 5



Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Total Proved + Probable + Possible Production Forecast
Production Rate - MMcfpd
400
380
360
340
320
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
Protected Volumes Avg Day
Protected Volumes Max Day
Total Field 3P Avg Day Rate
Total Field 3P Max Well Deliverability

Figure 6

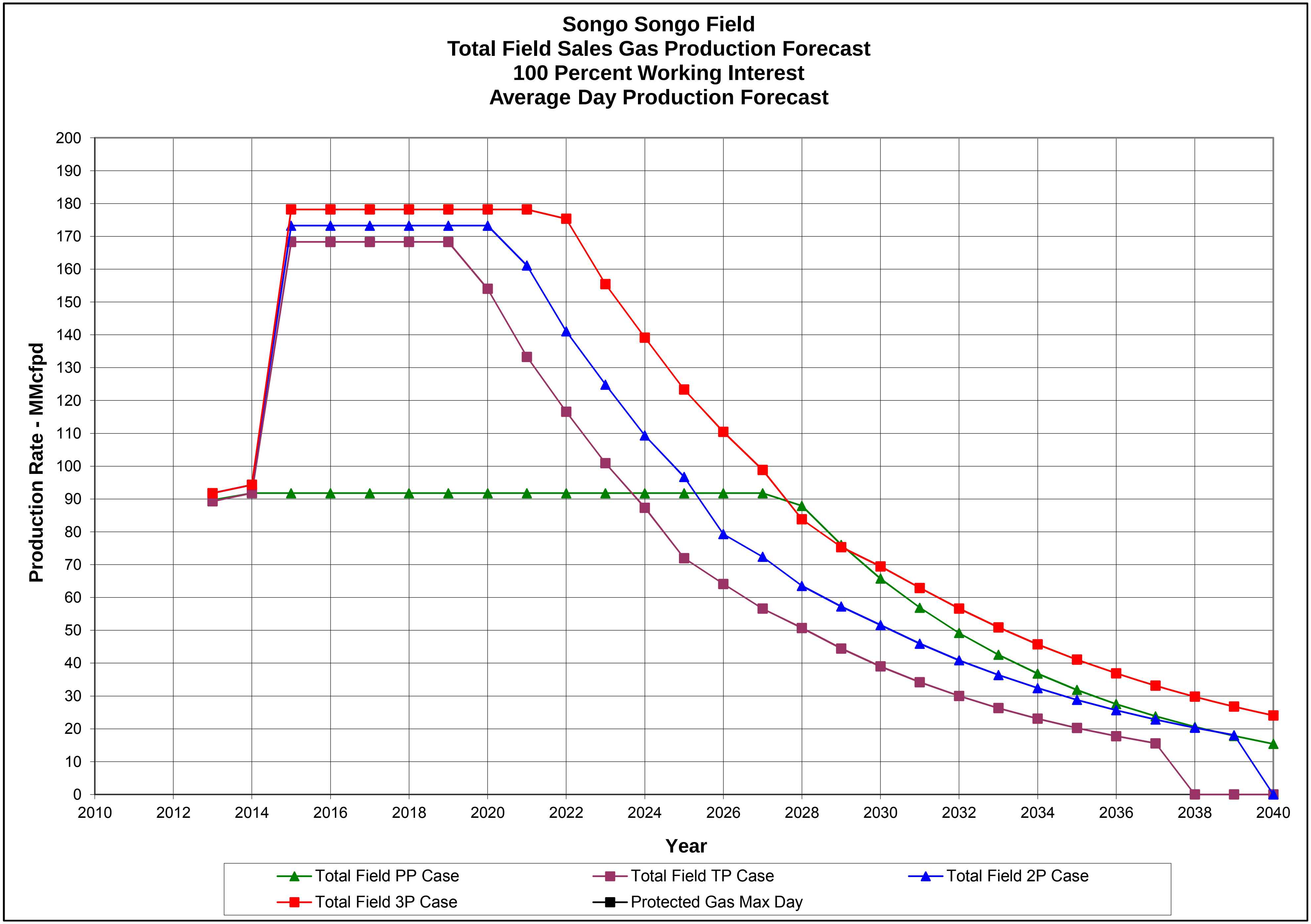
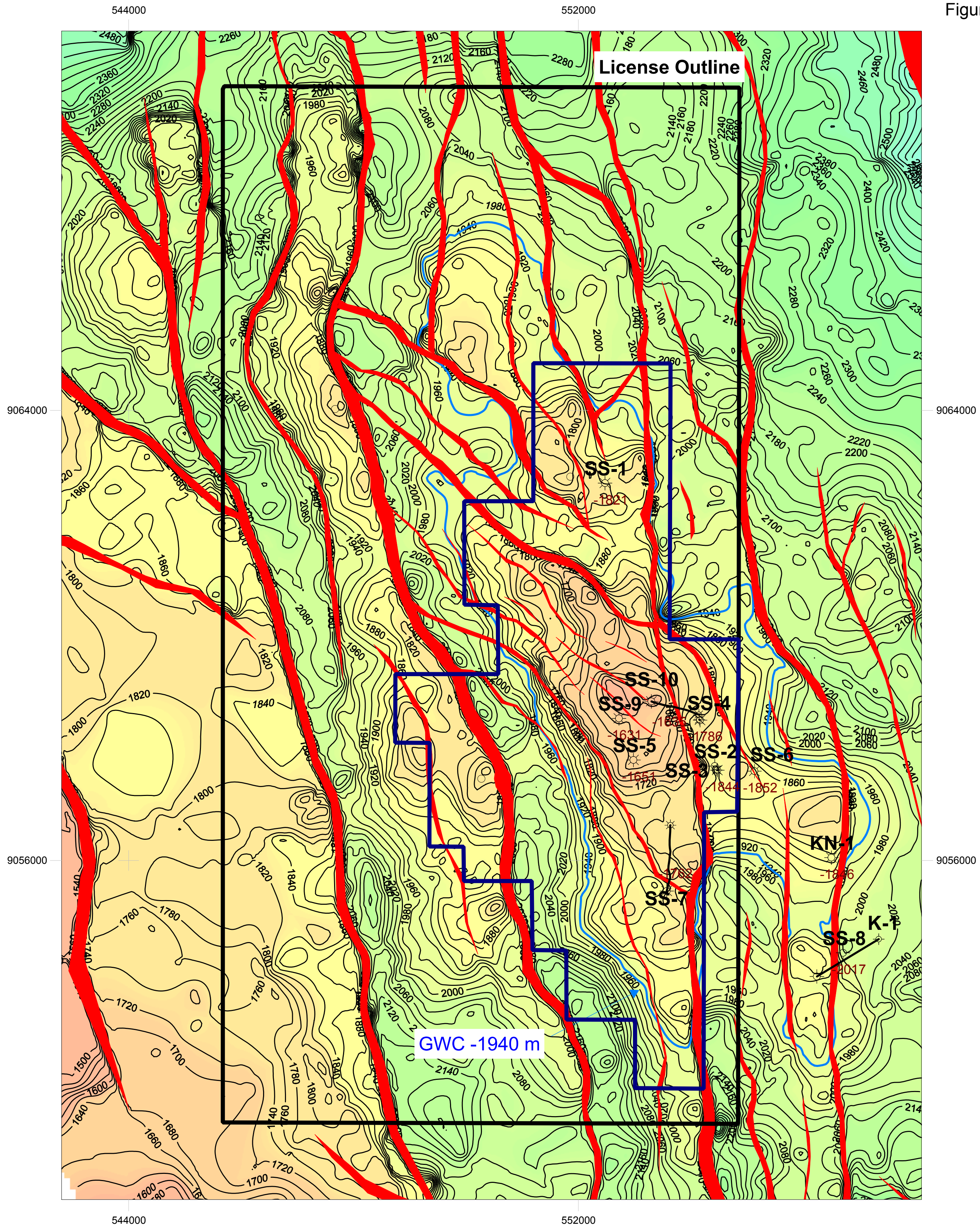

Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Average Day Production Forecast
Production Rate - MMcfpd
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
200
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
Total Field PP Case
Total Field TP Case
Total Field 2P Case
Total Field 3P Case
Protected Gas Max Day

Figure 7



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	
Drilling location	

N
W E
S

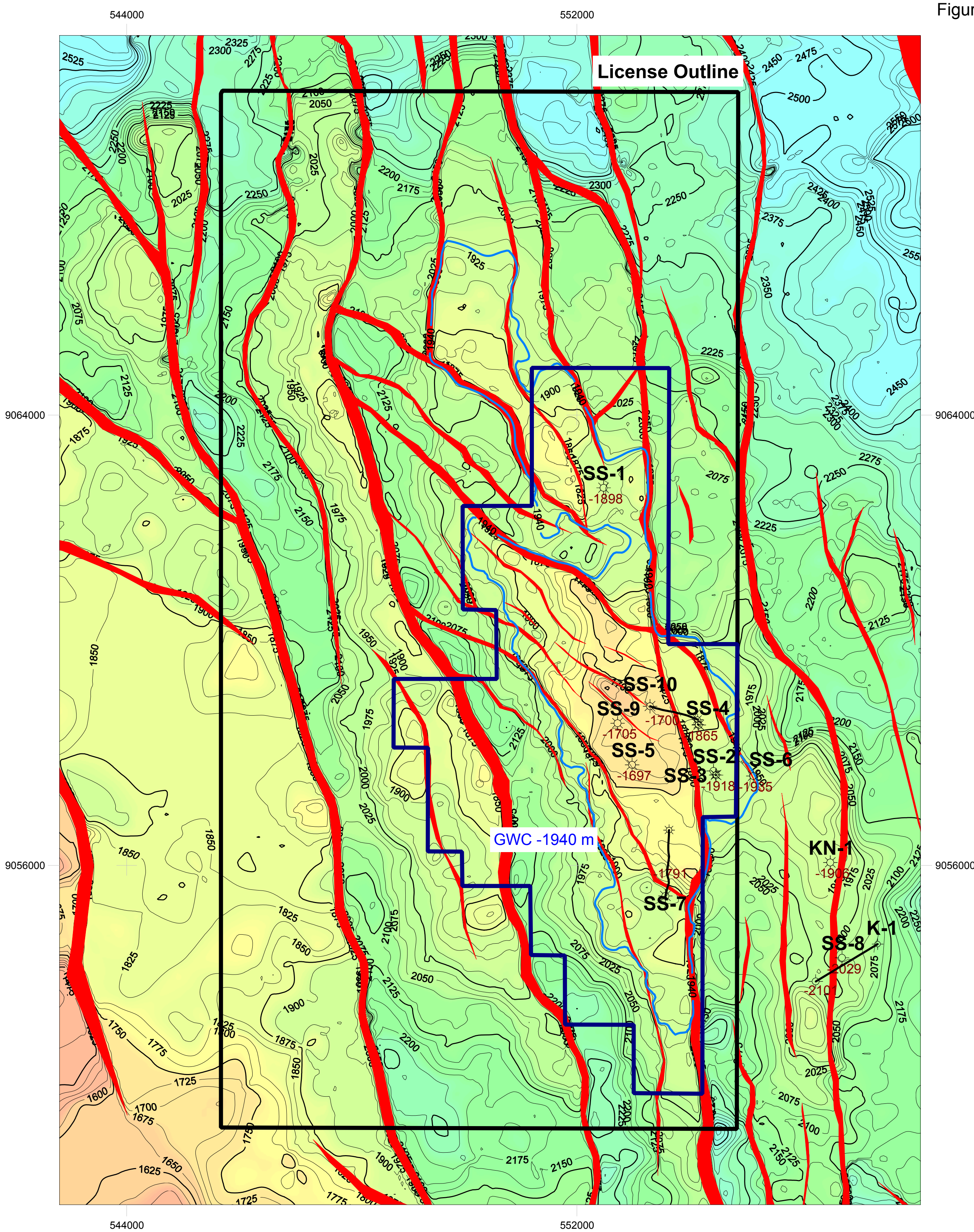
1 0 1 2 3 4 km

McDaniel & Associates Consultants Ltd.

Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Cenomanian Formation

Anatoli Tchernavskikh	Units – meters	14 April, 2009

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	
Drilling location	

N
W E
S

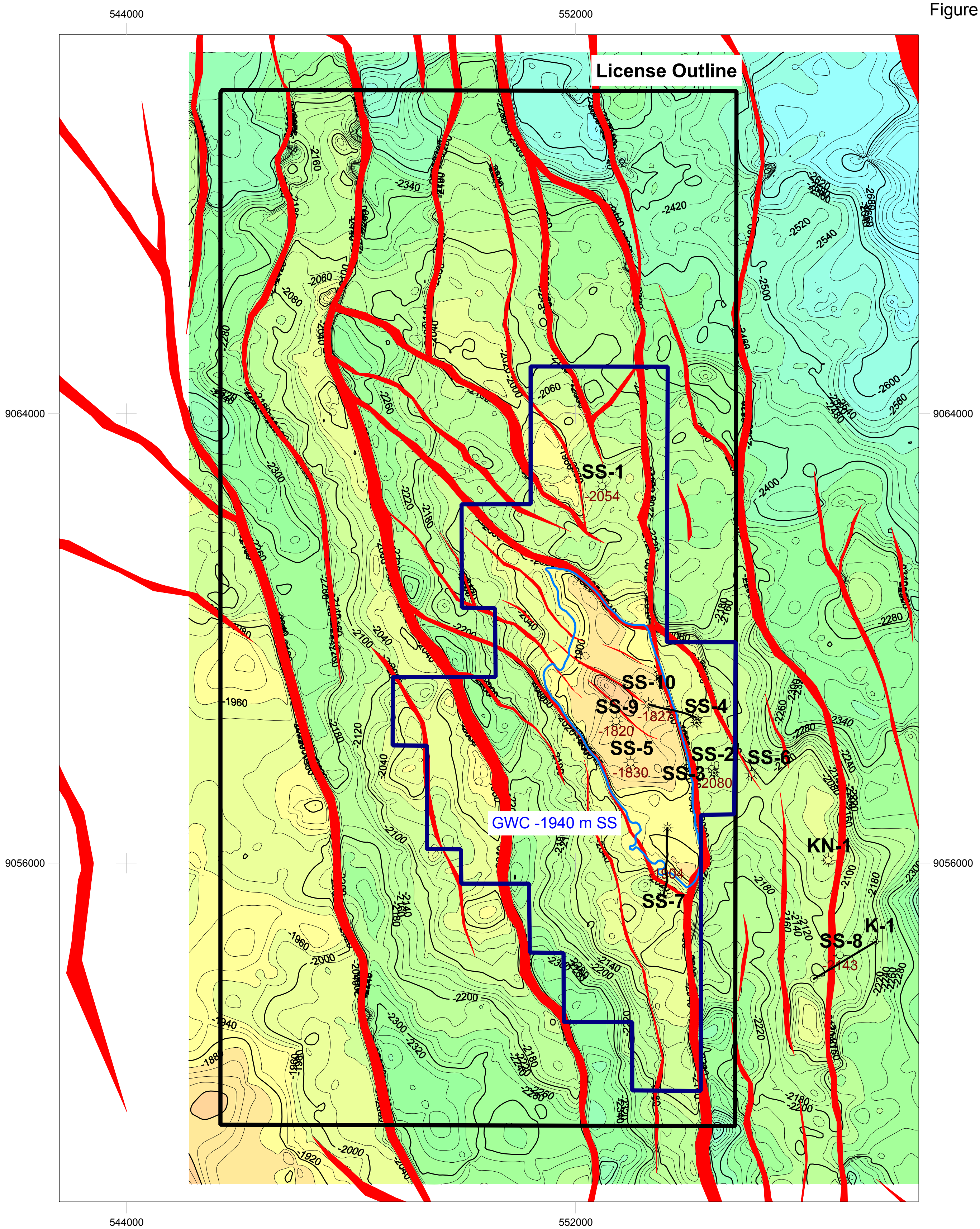
1 0 1 2 3 4 km

McDaniel & Associates Consultants Ltd.

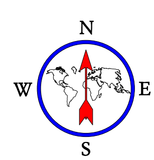
Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Neocomian Formation

Anatoli Tchernavskikh	Units – meters	14 April, 2009

Figure 9



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	
Drilling location	



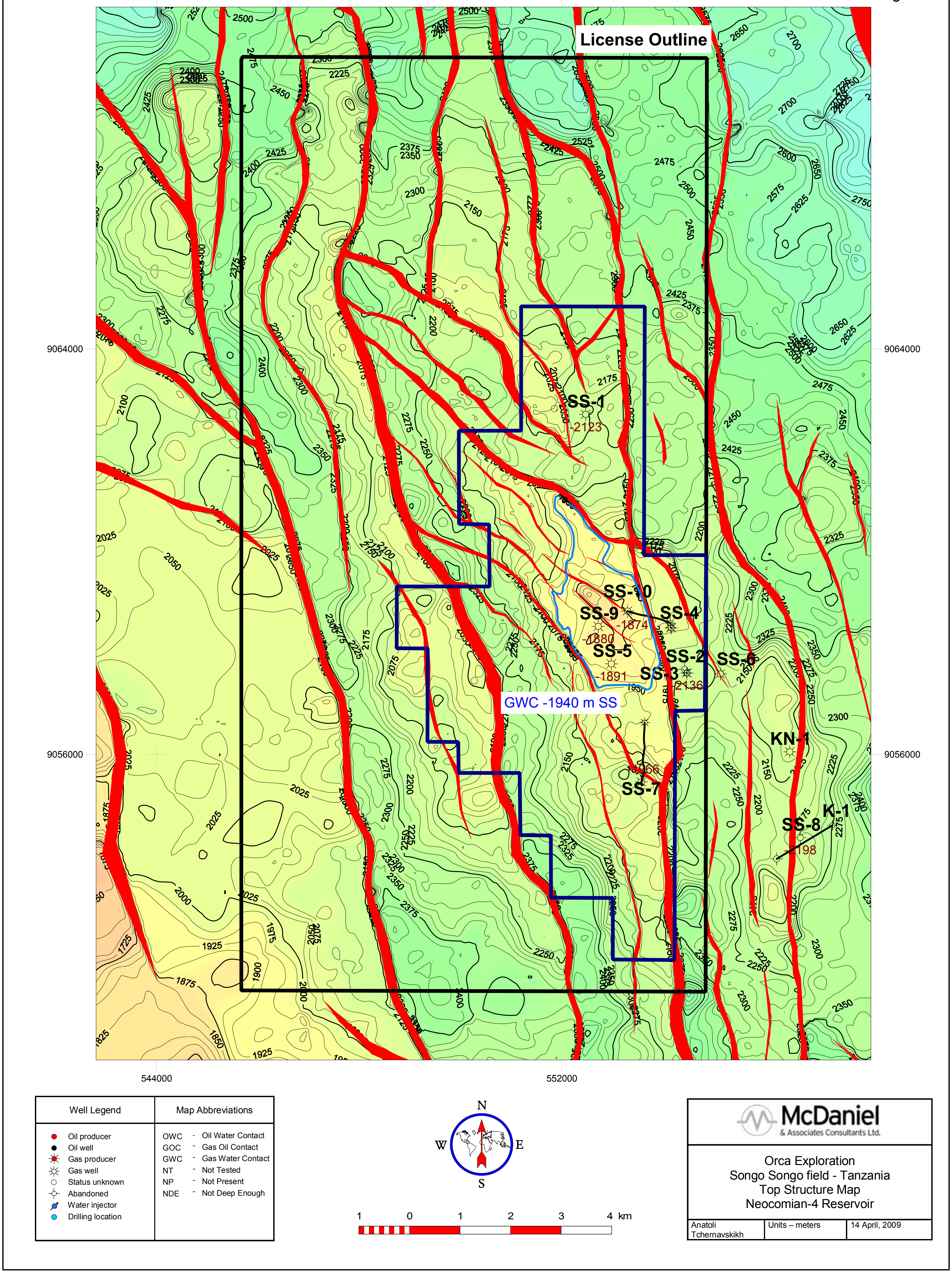
1 0 1 2 3 4 km

McDaniel & Associates Consultants Ltd.

Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Neocomian-5 Reservoir

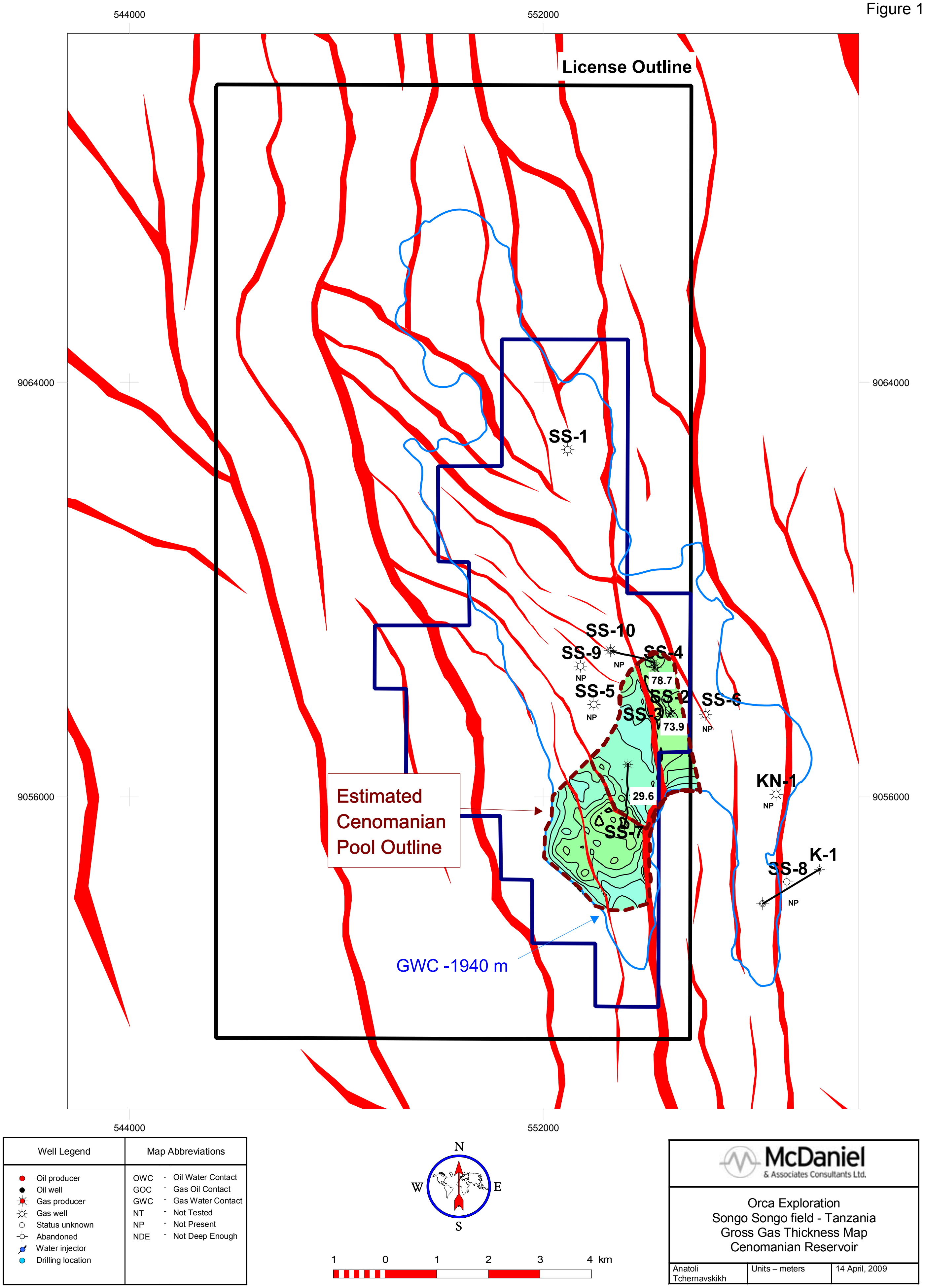
Anatoli Tchernavskikh	Units – meters	14 April, 2009

Figure 10



544000
552000
9064000
9056000
License Outline
SS-1
-2123
SS-10
SS-9
SS-4
-1874
-1880
SS-5
SS-2
SS-6
SS-3
-1891
-2136
GWC -1940 m SS
KN-1
SS-7
SS-8
K-1
N
S
W
E
1 0 1 2 3 4 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
McDaniel
& Associates Consultants Ltd.
Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Neocomian-4 Reservoir
Anatoli Tchernavskikh
Units – meters
14 April, 2009

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	
Drilling location	

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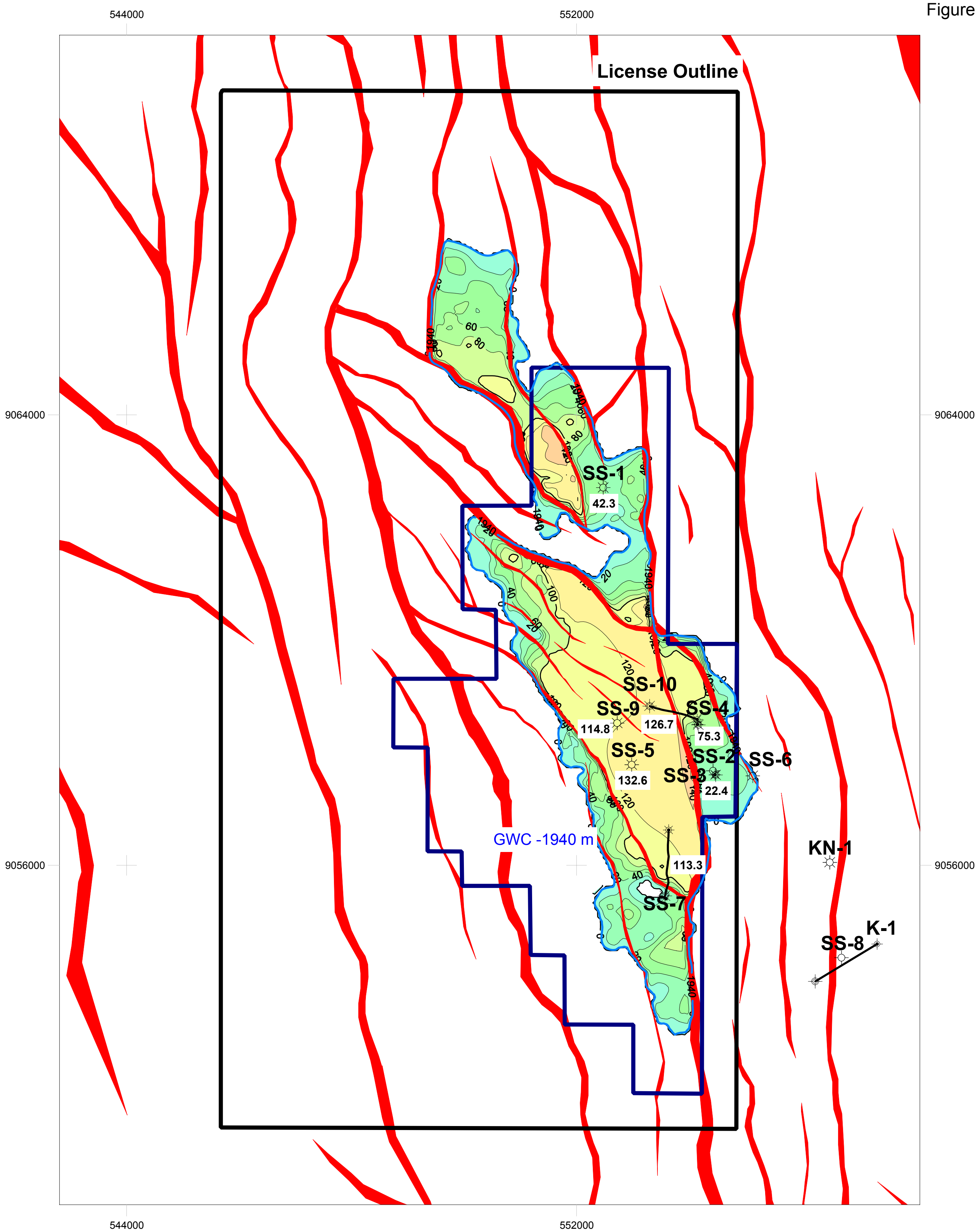
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Cenomanian Reservoir

Anatoli Tchernavskikh	Units – meters	14 April, 2009

Figure 12



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	
Drilling location	

N
W E
S

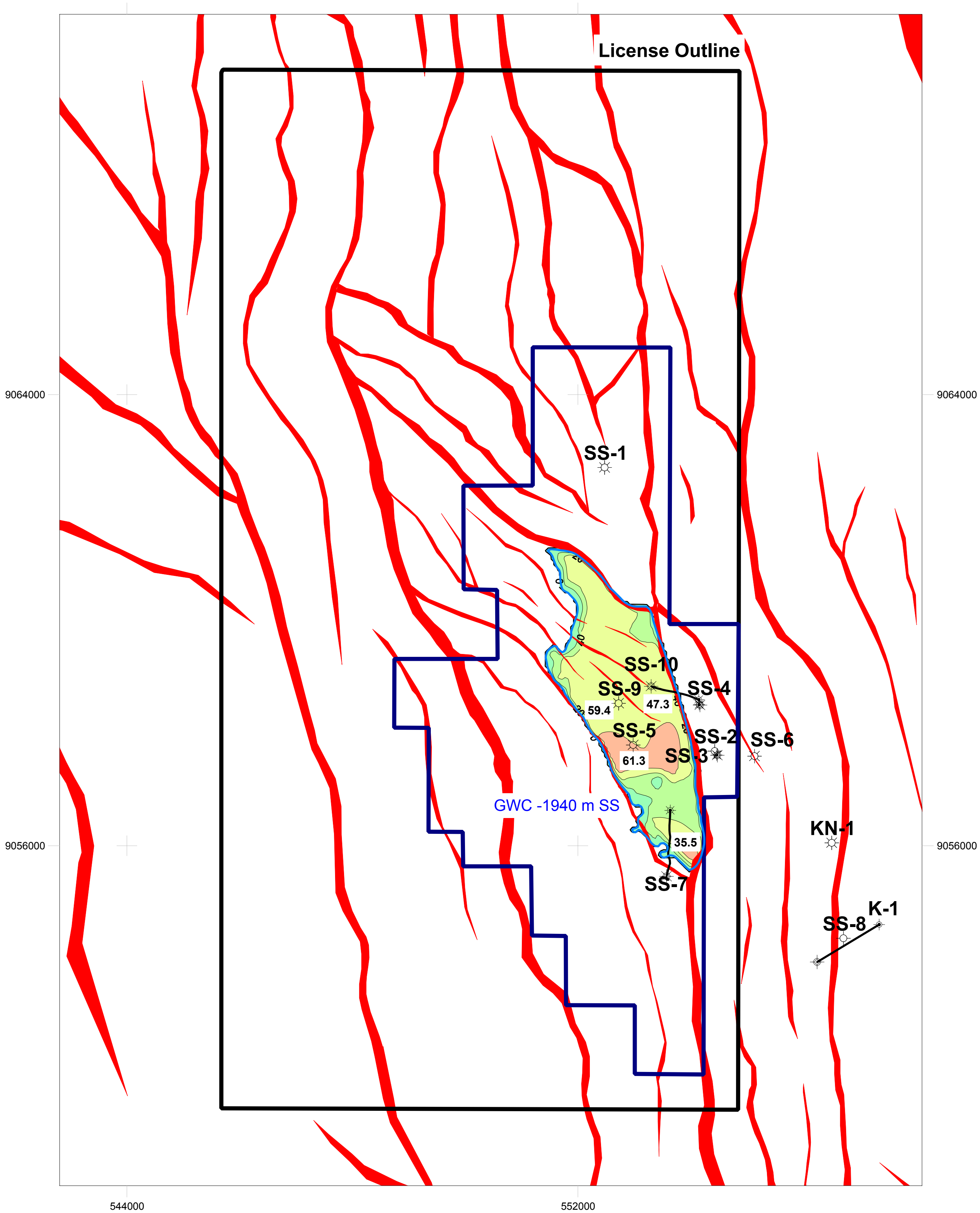
1 0 1 2 3 4 km

McDaniel
& Associates Consultants Ltd.

Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Albian & Neocomian Reservoirs 10 to 6

Anatoli Tchernavskikh	Units – meters	14 April, 2009

Figure 13



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	
Drilling location	

N
W E
S

1 0 1 2 3 4 km

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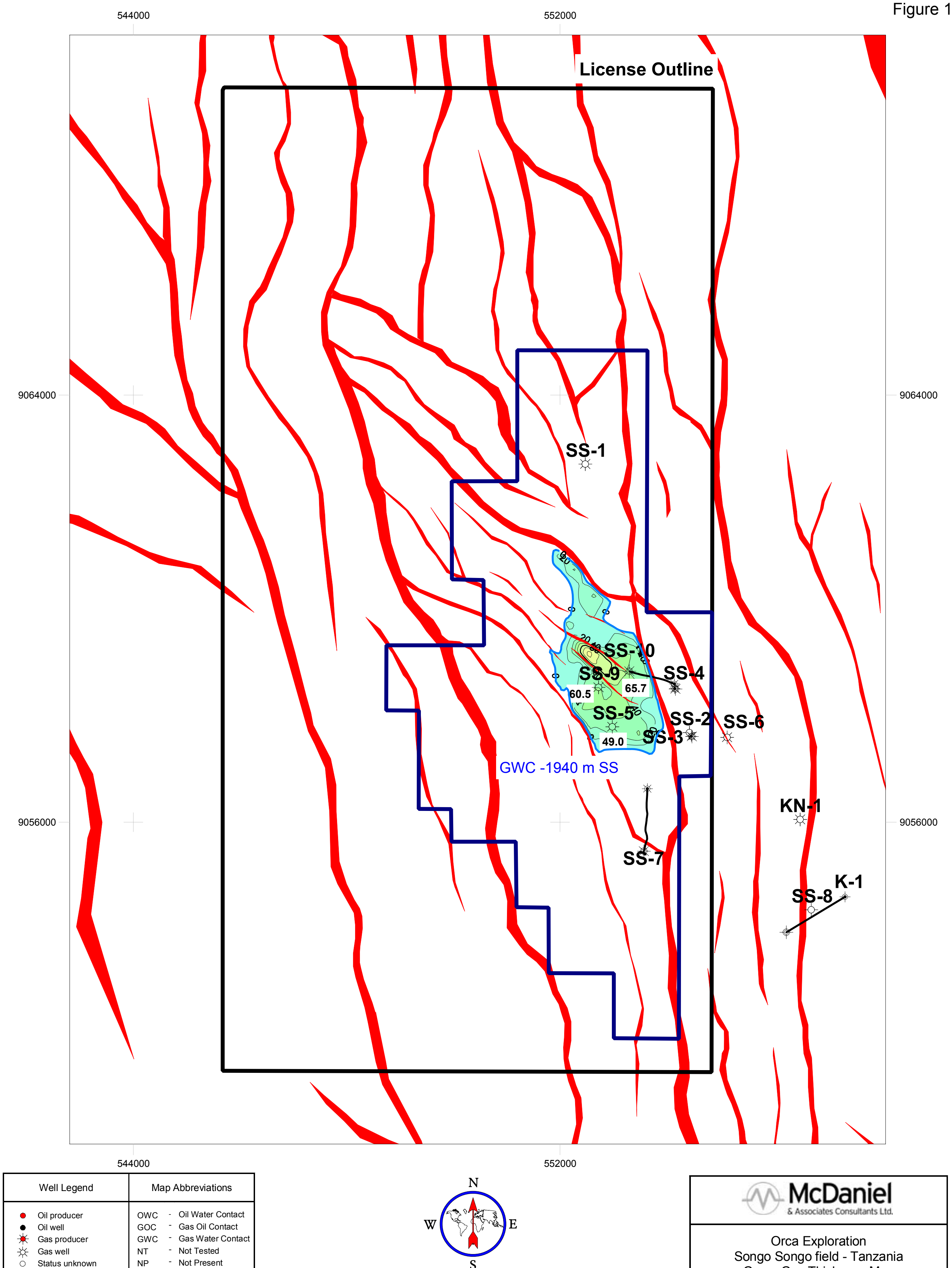
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Neocomian Reservoir 5

Anatoli Tchernavskikh	Units – meters	14 April, 2009

Figure 14

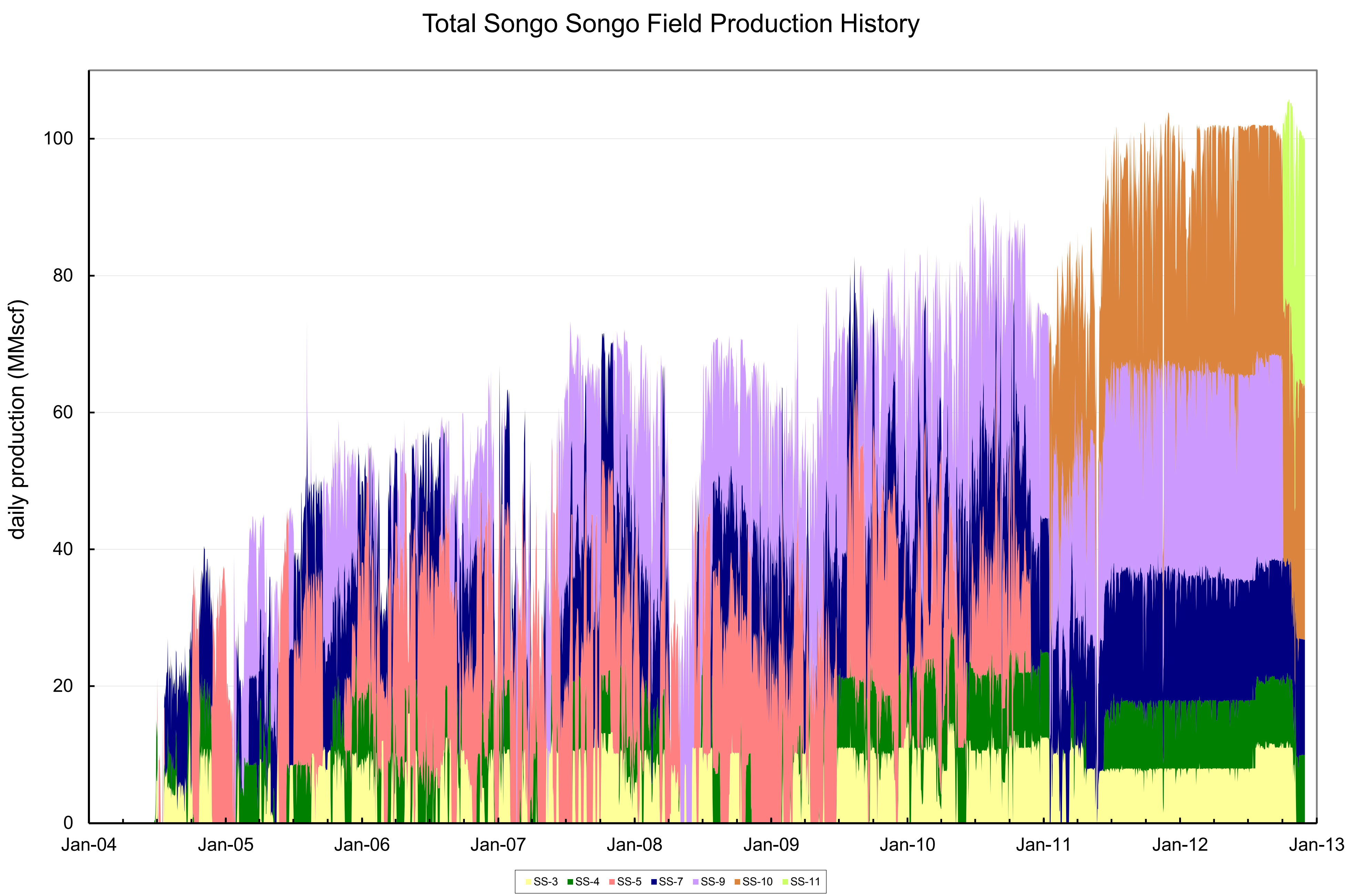


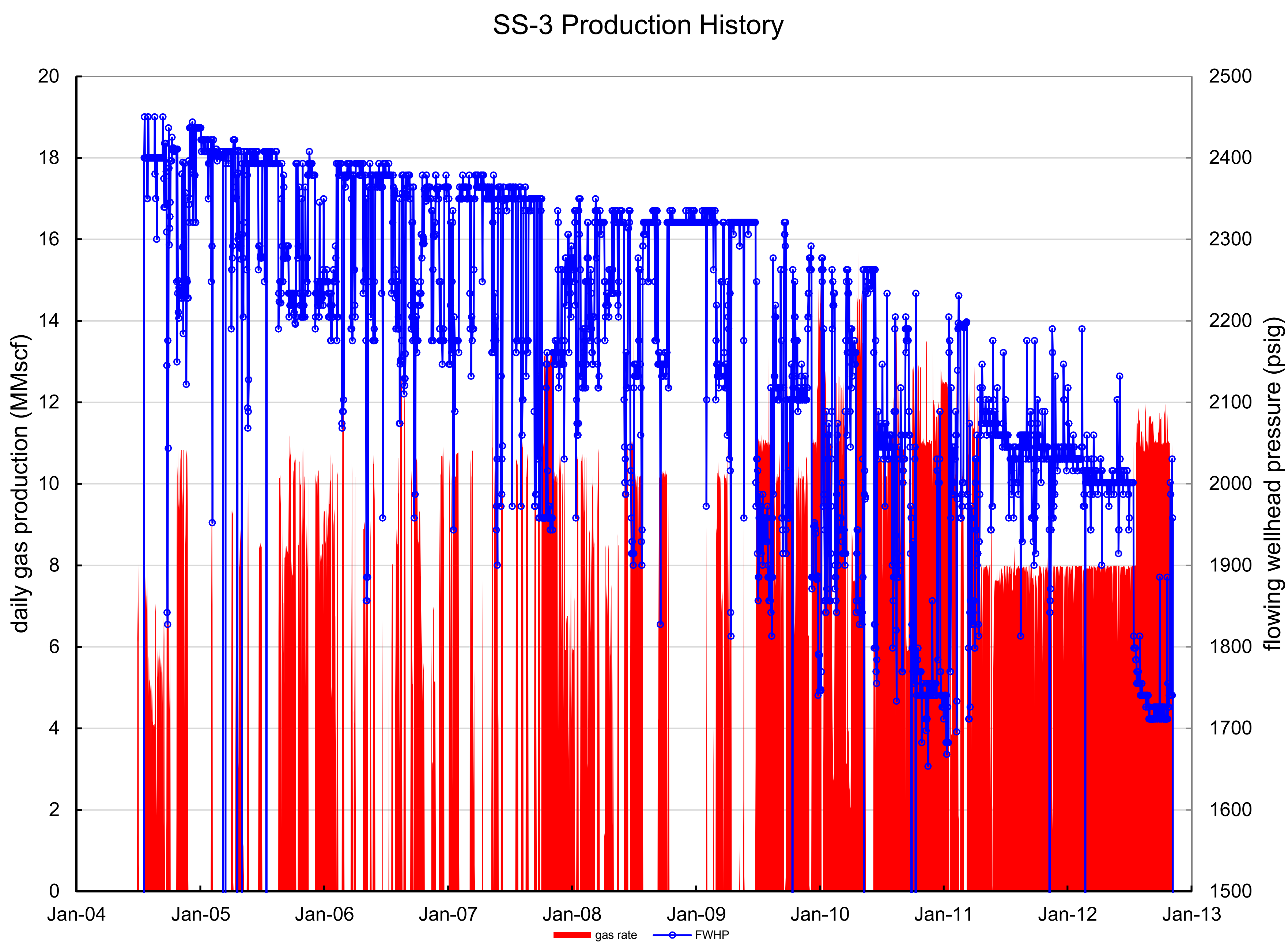
Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
Gas well	NT - Not Tested
Status unknown	NP - Not Present
Abandoned	NDE - Not Deep Enough
Water injector	
Drilling location	

McDaniel & Associates Consultants Ltd.

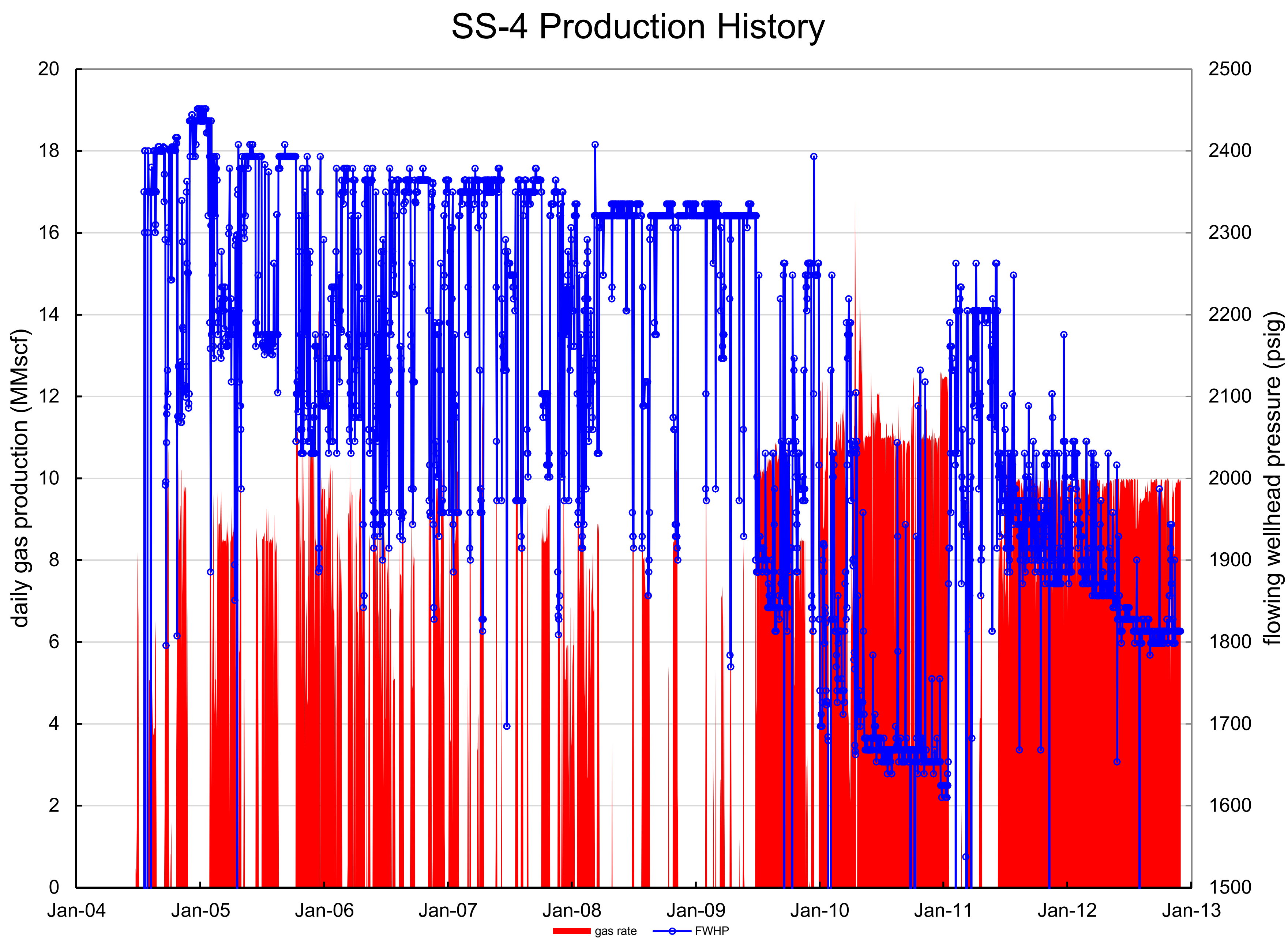
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Neocomian Reservoirs 1-4

Anatoli Tchernavskikh	Units – meters	14 April, 2009

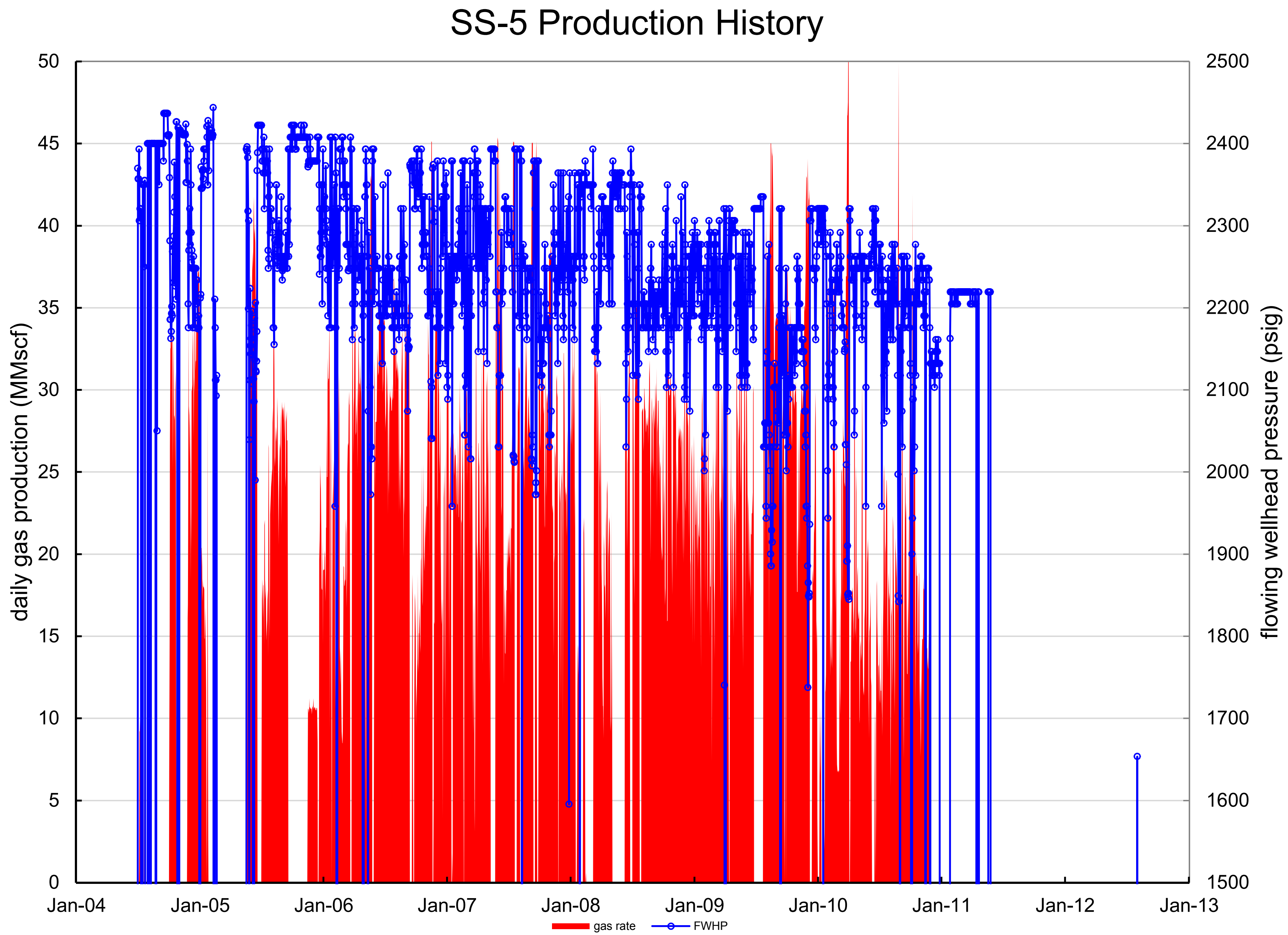

Total Songo Songo Field Production History
daily production (MMscf)
0
20
40
60
80
100
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
SS-3
SS-4
SS-5
SS-7
SS-9
SS-10
SS-11



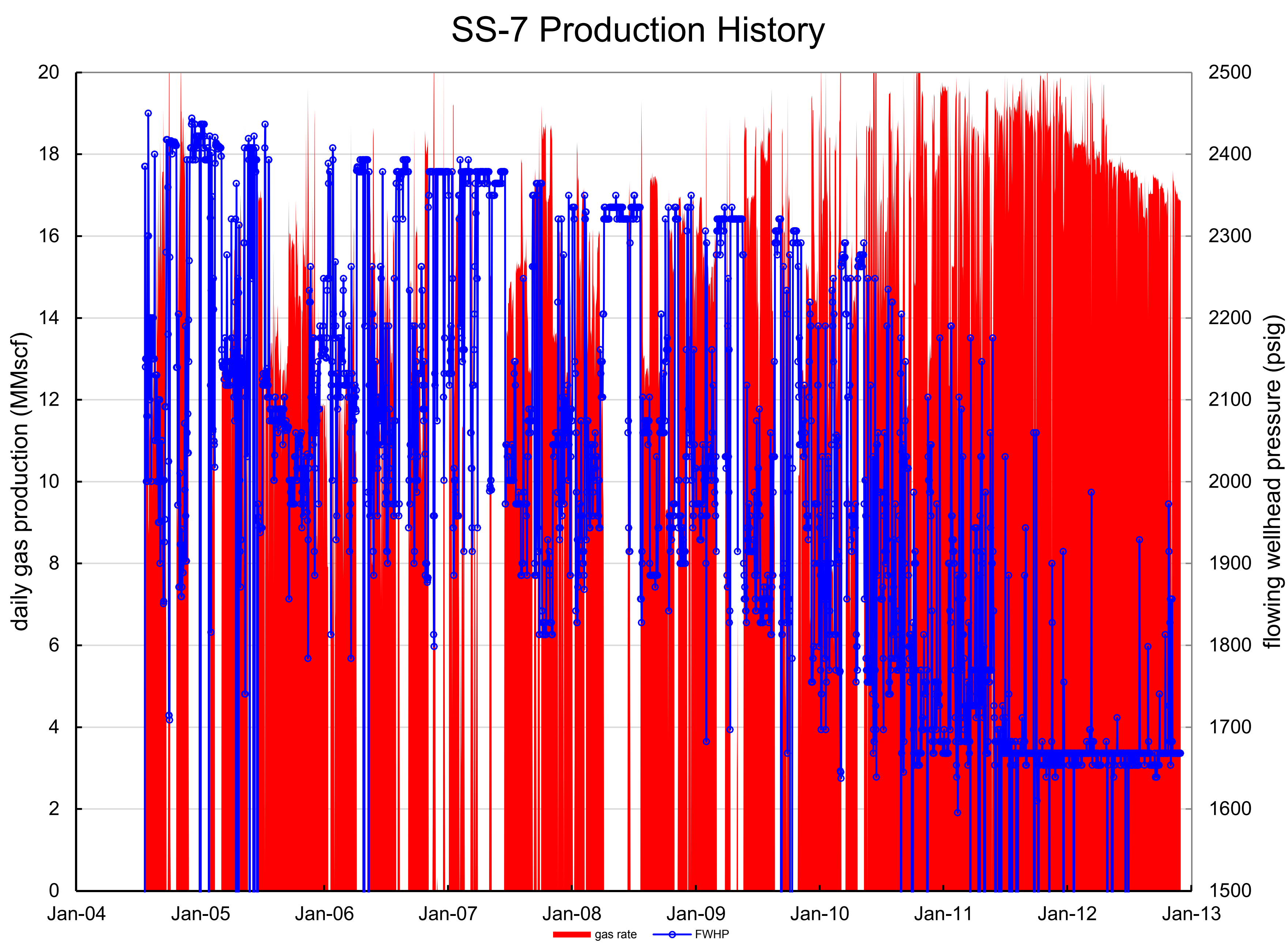
SS-3 Production History
daily gas production (MMscf)
flowing wellhead pressure (psig)
0
2
4
6
8
10
12
14
16
18
20
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
gas rate
FWHP

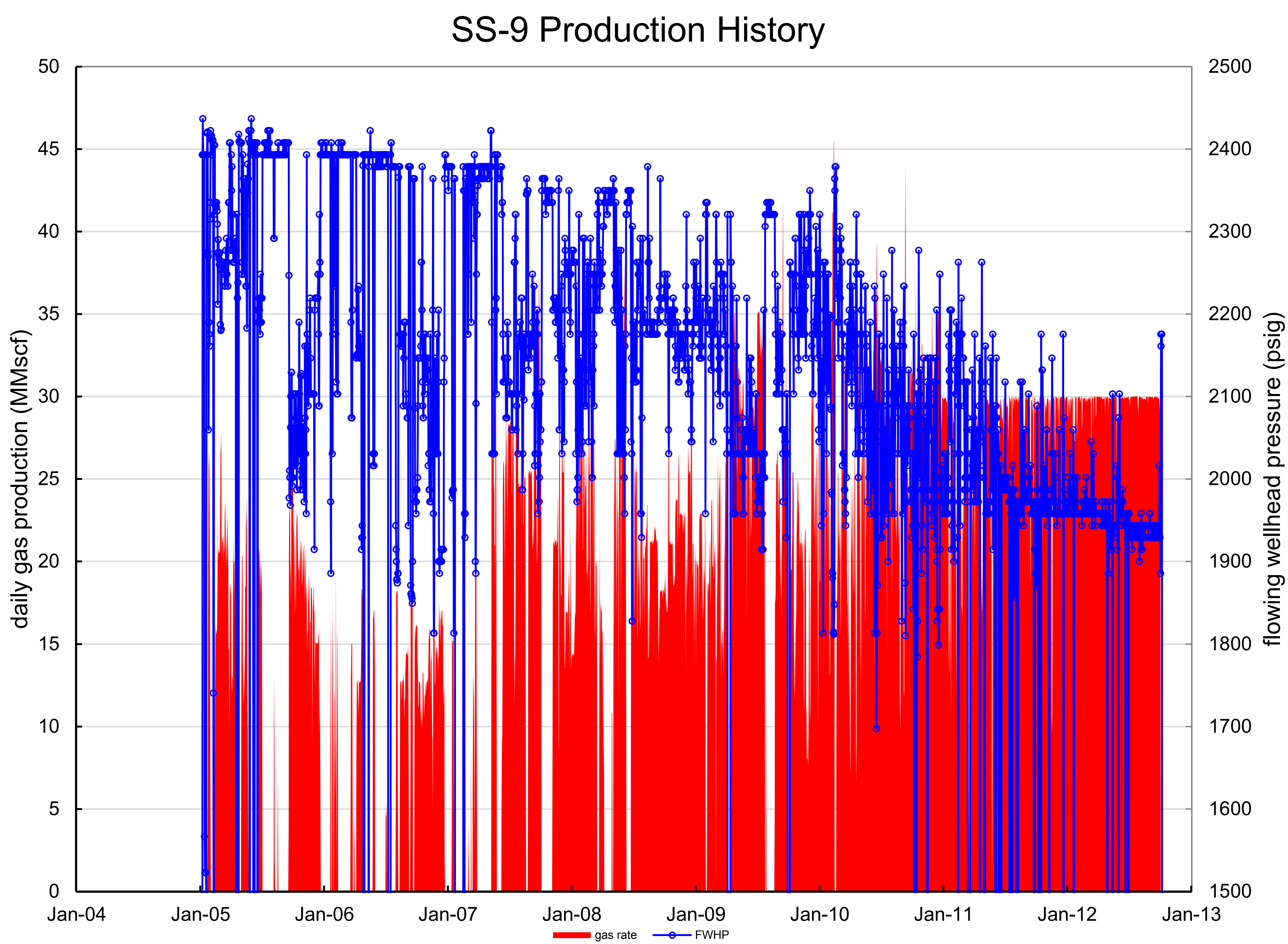


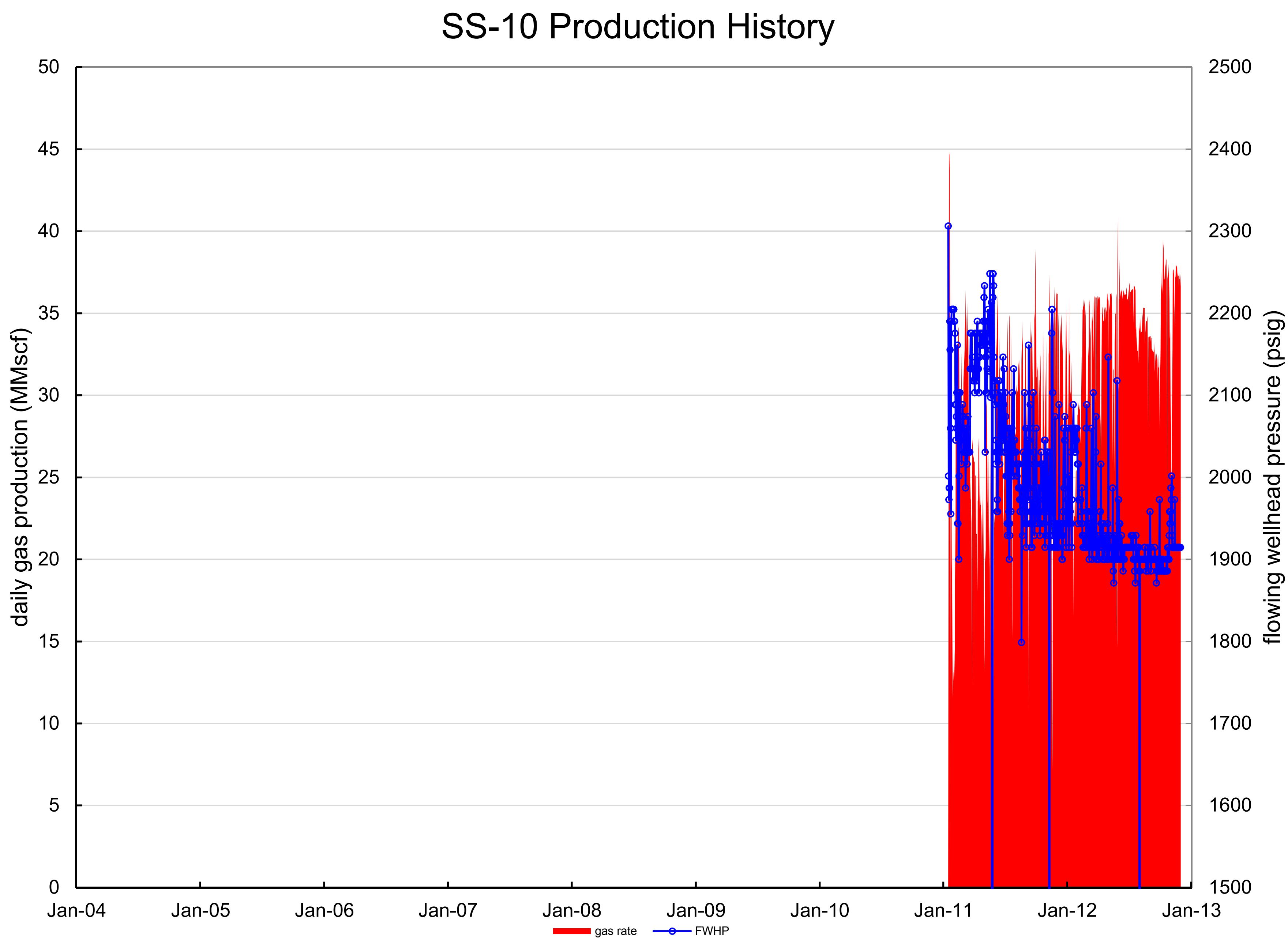
SS-4 Production History
daily gas production (MMscf)
flowing wellhead pressure (psig)
0
2
4
6
8
10
12
14
16
18
20
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
gas rate
FWHP



SS-5 Production History
daily gas production (MMscf)
flowing wellhead pressure (psig)
0
5
10
15
20
25
30
35
40
45
50
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
gas rate
FWHP


SS-7 Production History
daily gas production (MMscf)
flowing wellhead pressure (psig)
0
2
4
6
8
10
12
14
16
18
20
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
gas rate
FWHP


SS-9 Production History
daily gas production (MMscf)
flowing wellhead pressure (psig)
0
5
10
15
20
25
30
35
40
45
50
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
gas rate
FWHP



SS-10 Production History
daily gas production (MMscf)
flowing wellhead pressure (psig)
0
5
10
15
20
25
30
35
40
45
50
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
gas rate
FWHP

SS-11 Production History