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13 December 2010

ASX Announcement

Ryder Scott Report on Potential Oil Resource Estimates

Baraka Petroleum Ltd., ("Baraka" or "the Company") (ASX:BKP) is pleased to provide the Ryder Scott Company Petroleum Consultants (Ryder Scott), Canadian fully compliant N151-101, report entitled Evaluation of the Hydrocarbon Resource Potential Pertaining to Certain Acreage Interests in the Southern Georgina Basin.

This report evaluates the potential oil resources of the Baraka tenements in the Southern Georgina Basin, NT (EP 127 and EP128), where it owns an undivided 25% interest in joint venture with a Canadian partner. This report has been prepared by the internationally recognised independent resource-evaluation firm, Ryder Scott and is attached to this announcement.

The following summarises the resources from the Lower Arthur Creek "Hot Shale" on Baraka's lands according to Ryder Scott:

Unrisked Estimates of Undiscovered OOIP and Prospective Recoverable Oil Resources in the Lower Arthur Creek "Hot Shale"						
Exploration Permit	**Unrisked Undiscovered OOIP (Billion of Barrels)**			**Unrisked Prospective Recoverable Oil Resource (Billion of Barrels)**		
	Low	**Best**	**High**	**Low**	**Best**	**High**
EP 127	19.789	27.715	37.190	1.753	2.723	4.009
EP 128	34.969	48.934	65.718	3.097	4.812	7.084
Subtotal EP 127,128	**54.758**	**76.649**	**102.908**	**4.850**	**7.535**	**11.093**

Baraka's interest in the above Prospect Lower Arthur Creek "Hot Shale" is 25%.

Baraka also retains an undivided 75% working interest in approximately 75kms^2 around the Elkedra-7 well on EP 127, where previous drilling has indicated oil shows. This zone could be of significant value in the event of a discovery.

Yours sincerely

Collin Vost

Dip Financial Services(Financial Planning)
Dip AII AAII AFSAA.
Derivatives Accredited (ADA2)
Superannuation Accredited
Director

BARAKA PETROLEUM LIMITED

Evaluation of the Hydrocarbon Resource Potential
Pertaining to Certain Acreage Interests in the
Southern Georgina Basin

Northern Territory, Australia

As of
November 1, 2010

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

HOUSTON DENVER
CALGARY

TABLE OF CONTENTS

BARAKA PETROLEUM LIMITED
TABLE OF CONTENTS

DISCUSSION

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December 5, 2010

Mr. Collin Vost
CEO
Baraka Petroleum Limited
Shop 12 "South Shore Piazza"
85 The Esplanade
South Perth
WA 6151

File No: 8347RP10

Dear Mr. Vost;

Pursuant to your request, Ryder Scott Company-Canada (Ryder Scott) has prepared an evaluation of the hydrocarbon resource potential pertaining to the acreage interests of Baraka Petroleum Limited (Baraka) in the Southern Georgina Basin of the Northern Territory of Australia (NT) as of November 1, 2010.

Baraka, owns a 25 percent interest in the two Exploration Permits (EP 127 and EP 128) comprising approximately 31,750 square kilometers (7.85 million acres), in the Southern Georgina Basin (see Appendix 1, Figures 1 & 2). These permits were Farmed out by Baraka to Australia Energy Corp. (AEC) in 2010, through a Farmout Agreement between GBEPL and Baraka Petroleum Limited. GBEPL is the operator of these two new permits under the Farmout and Participation Agreement. All of the working interests in the two permits are subject to their proportionate share of certain royalties payable to the Government of NT and to the Native Stakeholders (Traditional Owners).

It should be noted that the resource prospects identified within Baraka's lands have very sparse seismic control and poor well control. Very few wells have been drilled within the entire Southern Georgina Basin within Australia's NT. In the vicinity of Baraka's two EPs, a total of only twenty nine exploration wells have been drilled, most of the wells were drilled by mining and oil exploration companies and a few were Government stratigraphic test wells.

It should be emphasized that no commercial hydrocarbons have been discovered to date on any of Baraka's prospects and there is no assurance any commercial hydrocarbons will be discovered as a result of Baraka's proposed exploration activities.

Resource Estimates

The resource estimates presented herein have been prepared in accordance with the Canadian standards set out in the National Instrument 51-101 (NI51-101) and in the Canadian Oil and Gas Evaluation Handbook (COGEH). Under Section 5.1.2 of COGEH (see Appendix 3), "*Petroleum is*

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defined as a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase". The term "*resources"* encompasses "*all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced*".

The resource estimates presented in this report are classified as *Undiscovered Petroleum Initially-in-Place (PIIP)* and *Prospective Resources.* COGEH defines *"Undiscovered PIIP, (equivalent to undiscovered resources), as that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development".*

For the purpose of further clarity, undiscovered hydrocarbon resource volumes are presented on various tables in this report as "*Unrisked Undiscovered Original Oil-in-Place (OOIP)"*. Prospective Resources are presented as *Unrisked Prospective Oil Resources.* The term "*unrisked*" means that no geologic risk (play risk) has been incorporated in the hydrocarbon volume estimates.

It should be clearly understood that the resource plays evaluated herein are high risk exploration plays. No commercial hydrocarbons have been discovered to date on any of Baraka's prospects. There is no certainty that any portion of the undiscovered resources will be discovered and that, if discovered, it may not be economically viable or technically feasible to produce any of the resources.

Exploration Play Types

This report addresses resources associated with both conventional and unconventional play types.

***Conventional Play Types*:** These are plays which typically have separate source rocks, reservoir rocks and trap rocks. The source rocks contain organic material which generates the hydrocarbons, which then migrate out of the source rock into porous and permeable reservoir rocks. The hydrocarbons are prevented from migrating out of the reservoir rock (trapped) by a layer of overlying impermeable trap rock. Often the reservoir is in hydrodynamic communication with an underlying aquifer. The conventional plays in this report consist of structural traps containing Hagen Member carbonate reservoirs, and combined structural-stratigraphic pinch-out traps containing Arthur Creek Shoal Reservoirs.

***Unconventional Play Types (Shale Oil and Gas Plays)*:** Oil and/or gas shale accumulations are regionally pervasive hydrocarbon deposits, which cut across structural boundaries. The rock in this type of unconventional accumulation is both source and reservoir. Like normal source rocks they usually contain high total organic carbon content (TOC). During the thermal generation of hydrocarbons from the organic matter within the shale, a large amount of the generated oil and/or gas is expelled, migrating to a reservoir or possibly escaping to the surface. However in this type of unconventional reservoir, a significant amount of the generated hydrocarbons remain trapped within the low permeability shales and siltstones as a "free" phase within fractures, the pore system and in the case of a shale gas, in an adsorbed state, adhering to the organic-rich component of the substrate. This type of accumulation may be normally or abnormally pressured (either underpressured or over pressured). The Lower Arthur Creek organic rich "Hot Shale" zone, have world class TOC averaging over 5 percent, and is recognized as both the primary hydrocarbon source rock in the basin as well as a potential, very large, unconventional shale oil reservoir.

Data Reviewed

AEC, on behalf of Baraka, provided Ryder Scott with well information on a number of the wells drilled on and in the vicinity of Baraka's two EPs (EP 127 and EP 128). AEC also provided commercial information regarding Baraka's ownership interests in the Southern Georgina Basin, including the terms and conditions of Baraka's EPs. AEC provided Ryder Scott with well logs in electronic (LAS) format, well information and core analysis reports on a number of the previous drilled wells on and in the vicinity of the two EPs. Ryder Scott prepared detailed petrophysical evaluations on approximately twelve of these wells for this report see the following table (see Appendix 2, Tables 1 & 2 for detailed petrophysical parameters). AEC also provided information of the old seismic lines (pre 2009) that run over Baraka's two EPs.

LIST of Wells Evaluated by Ryder Scott	
Area	**Wells**
Toko Basin	Owen-2
	Hacking-1
	Bradley
	Mulga-1
	Netting Fence
	Todd-1
Dulcie Basin	Amaroo-1 & 2
	Randall-1
	Phillip-2
	Huckitta-1
	Lucy Creek-1
	Baldwin-1
	Hunt-1
	MacIntyre-1
	Sandover-13
	Ross-1

Northern Territory Petroleum and Natural Gas Regulations

Introduction

According to recent publicly available information, Australia imports approximately 55 percent of the oil used in the domestic market and Australia is therefore particularly interested in increasing domestic oil production. The Federal Government of Australia and the State Government of the NT both have very positive attitudes towards oil and gas exploration and development and very favorable fiscal regimes (see below). In addition, the governing law is based on English common law (as in Canada) and the political system is democratic and stable.

The Government of the NT is the owner of the petroleum and natural gas rights within its boundaries, including the portion of the Southern Georgina Basin situated in NT (see Appendix 1, Figure 1). The

Minister for Business, Industry and Resource Development, NT is responsible for managing all oil and gas activity within the NT and it is this Government Department that issued the two EPs currently being explored by Baraka. The two EPs (EP 127 and EP 128) comprise approximately 31,750 square kilometers (7.85 million acres). Each of the two EPs originally had their own required work programs and expenditures. Under the NT Government's Petroleum and Natural Gas regulations, a company is first granted an Exploration Permit (EP) to undertake the exploration activity. In the event that an oil and/or gas discovery is made, a Production Licence (PL) may be granted for part or all the EP lands to allow development and production of the discovery.

Fiscal and Royalty Regime

The NT Government has a favorable oil and gas fiscal and royalty regime consisting of a 10 percent Government Lessor Royalty on oil and gas production. EP 127 and EP 128 has a variable scale (3.0% to 5.0%) two tier oil and gas royalty based on cumulative production, both payable to the Central Land Council, representing the Native Stakeholders who own the surface rights over much of NT (see below):

Native Stakeholders Royalty Agreed on EP 127 & EP 128

i. 3.0% up to 3,000 barrels per day; and

ii. 5.0% in excess of 3,000 per day.

The combined royalty is low by world standards, as is the corporate income tax rate of approximately 30 percent.

Summary of the Baraka Farmout and Participation Agreements

Northern Territory Oil Pty. Ltd. (NTO) is the original owner of the two exploration permits. Baraka Petroleum Limited (Baraka) subsequently entered into Farmout Agreements with NTO on both permits. The terms of the NTO Farmout Agreements called for Baraka (as Farmee) to pay 100 percent of the original NT government minimum work commitment to earn 75 percent in both EP 127 and EP 128. On April 1, 2010, Baraka signed the two Baraka Farmout Agreements with AEC's wholly owned subsidiary GBEPL, covering EP 127 and EP 128, and a separate Farmin and Assignment Agreements between NTO, Baraka and GBEPL covering each permit, facilitated AEC's entering into these two new exploration permits.

The following is a brief summary of the pertinent obligations which AEC must satisfy to earn its 50 percent working interest in both EPs:

1. AEC is required to pay 100 percent of the cost to undertake the minimum work program
2. AEC must undertake the minimum NT work commitment on EP 127 and EP 128 for Year 3 starting June 1, 2010 (see NT Minimum Work Commitments for EP 127 and EP 128 below).
3. Commence drilling one well on either EP 127 or EP 128 by the first day of the 6th month of Year 3 (December 14, 2010). The well is to be drilled to a depth which is the greater of 600 meters or 20 meters into the pre-Arthur Creek Formation.
4. Commission a resource evaluation report pertaining to either EP 127 and/or EP 128, on or before the four months after the signing of the Farmout Agreement (on or before August 1, 2010).

Baraka has confirmed that AEC has made a non-refundable payment of AUS$100,000 to Baraka and thereby has earned its 50 percent working interest in both EP 127 and EP 128 and has became the Operator of the two permits. AEC is still required to fund 100 percent of the above Farmout Commitment. If the above work program is not completed by the above schedule, the Farmout can be terminated by Baraka and AEC forfeits its 50 percent working interest. Therefore as of the date of this report, AEC owns a 50 percent working interest, Baraka owns a 25 percent working interest and Northern owns the remaining 25 percent working interest in EP 127 and EP 128.

Summary of Terms of the Exploration Permits EP 127 and EP 128

NTO was officially granted the original permits on December 18, 2007. On March 17, 2010, the NT Department of Resources granted NTO (as current title holder) a six month Suspension and Extension for EP 127 and EP 128. Approval was also granted to vary the Year 2 minimum work requirements for each permit. It is our understanding that as of the dating of this report, that the NT Minimum Work Requirements for Year 1 and Year 2 for both EP 127 and EP 128 have been completed.

EP 127 (Alice Springs Sheet SF53, 184 Whole and Part blocks)

- **EP Interest:** *Baraka 25%, AEC 50% and NTO 25%*
- **Area:** *15,780 square kilometers (3.90 million acres)*
- **Grant of Exploration Permit:** *December 18, 2007*
- **Suspension of Exploration Permit:** *Six Month Extension (issued March 17, 2010) commencing on December 14 to June 13, 2010).*
- **Term of Exploration Permit:** *5 years, with 6 month extension to June 13, 2013*
- **Royalty:**
  - *i. NT Government: 10%*
  - *ii. Native Stakeholders: 3.0% - 5.0%.*

EP 127

Year of Term of Permit	Permit Year Start	Permit Year End	Minimum Work Requirements EP 127	Status and Estimated Expenditure in Constant Dollars $AUD (Indicative Only)
1	December 14, 2007	December 13, 2008	Geological and Geophysical Studies	Completed
Six Month Suspension and Extension of Permit Dated March 17, 2010				
2	December 14, 2008	June 13, 2010	Stratigraphic review Satellite structural and fracture image study	Completed
3	June 14, 2010	June 13, 2011	Acquire seismic data	$250,000
4	June 14, 2011	June 13, 2012	Acquire seismic data Contingent on seismic results drill one well to either 600m or 1200 meters	$600,000 to $1,800,00
5	June 14, 2012	June 13, 2013	Drill one well to 600 meters Contingent on Year 4 drilling results drill two wells to 600m or one 1200 meters	$600,000 to $1,800,00

EP 128 (Alice Springs Sheet SF53, 194 Whole or Part Blocks)

- **EP Interest:** *Baraka 25%, AEC 50% and NTO 25%*
- **Area:** *15,970 square kilometers (3.95 million acres)*
- **Grant of Exploration Permit:** *December 18, 2007*
- **Suspension of Exploration Permit**: *Six Month Extension (issued March 17, 2010) commencing on December 14 to June 13, 2010).*
- **Term of Exploration Permit:** *5 years, with 6 month extension to June 13, 2013*
- **Royalty:** i. *NT Government: 10%*
  ii. *Native Stakeholders: 3.0% - 5.0%.*

EP 128

Year of Term of Permit	Permit Year Start	Permit Year End	Minimum Work Requirements EP 128	Status and Estimated Expenditure in Constant Dollars $AUD (Indicative Only)
1	December 14, 2007	December 13, 2008	Geological and Geophysical Studies	Completed
Six Month Suspension and Extension of Permit Dated March 17, 2010				
2	December 14, 2008	June 13, 2010	Stratigraphic review Satellite structural and fracture image study	Completed
3	June 14, 2010	June 13, 2011	Acquire seismic data	$250,000
4	June 14, 2011	June 13, 2012	Acquire seismic data Contingent on seismic results drill one well to either 600m or 1200 meters	$600,000 to $1,800,00
5	June 14, 2012	June 13, 2013	Drill one well to 600 meters Contingent on Year 4 drilling results drill two wells to 600m or one 1200 meters	$600,000 to $1,800,00

Oil and Natural Gas Infrastructure

The Southern Georgina Basin is located approximately 250 kilometers northeast of the city of Alice Springs and 1,000 kilometers southeast of Darwin. Darwin is a major port city in the NT, situated on the northern coast of Australia (see Appendix 1, Figure 3). Darwin has a major liquefied natural gas (LNG) facility and export terminal which is fed by offshore fields. It is our understanding that currently the plant is running at approximately one-third capacity. A major north-south pipeline runs to the west of Baraka's permit areas and connects the Amadeus basin gas fields with Darwin. The north-south line which supplies Darwin could be a possible route to the LNG facility if natural gas were to be discovered. The pipeline parallels both the major north-south Stuart Highway and a major railway line. Secondary roads cut through EP 127 and EP 128, and connect to major highways and the previously mentioned railway. The local environment is typified by very hot, desert conditions and a short rainy season characterized by heavy rains and flash floods.

If Baraka successfully discovers oil and or gas reserves on its EPs its ability to generate revenue will depend on its ability to construct and/or acquire space on existing pipelines or find alternative delivery methods. In the case of oil discovery initial options may include trucking the oil to market but if the natural gas is discovered or significant oil volumes are discovered construction of a new pipeline from the Southern Georgina Basin will likely be required.

Reconstruction of the Neoproterozoic (Rodinia) Supercontinent

Over the long geological history of the earth, the relative position of the various continental tectonic plates has changed. Supercontinents have broken up and then come back together a number of times. In Neoproterozoic times (800 to 540 mya), the Georgina Basin was formed as part of the Rodinia Supercontinent in close proximity to other Rodinia basins in Siberia, Oman and China (see Appendix 1, Figure 4). All of these basins contain Cambrian oil source beds and reservoir rocks and have proved production from billion barrel oil fields.

The Southern Georgina Basin, Northern Territory, Australia

Introduction

The Georgina Basin of the NT represents one of the few remaining virtually unexplored, hydrocarbon prospective, onshore sedimentary basins in the world. The fact that this basin is located in a country with a stable political, legal and regulatory system makes this basin all the more significant. The Southern Georgina Basin covers more than 100,000 square kilometers (24.7 million acres) in the NT and the western part of Queensland. Baraka's two Exploration Permits are situated over what is believed to be a prospective part of the basin. Very few wells have been drilled within the entire Southern Georgina Basin making the basin by North American standards virtually unexplored. Within and in the vicinity of Baraka's two EPs a total of only twenty nine wells have been drilled, including twinned wells. A number of the wells were drilled by mining exploration companies, some of them very shallow, some by the NT Government as stratigraphic test wells and the some by oil companies (see Appendix 1, Figure 2). In 1991, a small amount of poor quality 2D seismic was acquired by Pacific Oil and Gas Pty., the oil and gas arm of Rio Tinto, a large Australian mining company. Pacific Oil also drilled the eight most recent wells (1989 - 1991), all of which had shows but were abandoned. The existence of giant oil and gas fields in Neoproterozoic/Cambrian rocks in Russia (Siberia) and in the Middle East (Oman), with recoverable oil reserves in the billions of barrels, has resulted in renewed exploration interest in other similar aged basins throughout the world. Also the great technical advances and widespread success in horizontal drilling and multistage frac stimulation of unconventional oil shale plays in North America have made international oil shale zones like the Arthur Creek Hot Shale found in the Southern Georgina Basin valuable exploration prospects. The Southern Georgina Basin, onshore Australia, hosts high quality source beds and potential conventional and unconventional reservoir rocks. We believe that this basin is one of the most prospective onshore basins in Australia with potential for both very large conventional and unconventional oil and gas deposits.

Geology, Structure and Hydrocarbon Potential of the Southern Georgina Basin, NT

Introduction

Although there is no production from the Southern Georgina Basin, there are similarities to the producing Amadeus Basin located to the southwest. In two fields located south and west of Alice

Springs, both light oil and natural gas have been produced in commercial quantities for several years. The Palm Valley Gas Field (NT estimated 2P reserves of 229 billion cubic feet) is currently producing gas. The Mereenie Gas and Oil Field (NT estimated 2P gas reserves of 325 billion cubic feet and light oil reserves of 18.4 million barrels) is currently producing gas and oil. A third field, Dingo, also has proven recoverable resources of approximately 20 billion cubic feet of gas but it is currently uneconomic to produce due to low gas prices and tie-in distance. The main reservoir in these fields is fractured Ordovician sandstone with secondary reservoirs found in Cambrian and Neoproterozoic rocks. The potential of deeper Cambrian rocks in Amadeus has not been tested to date. Only a few wells were drilled deep enough to evaluate the older formations.

There are strong similarities between the petroleum system in the Southern Georgina Basin to prolific conventional oil and gas basins in Western Canada, both stratigraphically and lithologically. The Mississippian Turner Valley-Elkton erosional sequence in Western Alberta is analogous to the Georgina Basin strata and the analogy is even stronger with the Mississippian Lodgepole-Mission Canyon carbonate ramp sequence in southeast Saskatchewan. The Alberta Mississippian section has produced over 283 million cubic meters (10 trillion cubic feet) of gas and over 159 million cubic meters (1 billion barrels) of oil from a variety of trapping mechanisms and pool sizes. The Lodgepole-Mission Canyon carbonate ramp sequence in southeast Saskatchewan is more oil prone and has several million cubic meters (billion barrels) of in-place-oil reserves in conventional carbonate and sandstone reservoirs that are similar to those in the Thorntonia Carbonates and Steamboat Sandstones in the Southern Georgina Basin.

There are also strong technical similarities between the Lower Arthur Creek organic rich “Hot Shale” in the Southern Georgina Basin and the unconventional oil targets within the Bakken Oil Shale in the Williston Basin of Canada and United States (US). Southeast Saskatchewan is situated within the northern part of the very prolific Williston Basin, which covers the US northern states of Montana and North Dakota. Upper Devonian organic rich Bakken Shales are recognized as one of the primary hydrocarbon source rocks for both the Saskatchewan and US portions of the Williston Basin. More recently the Bakken Shale itself has been recognized as the largest and most prolific unconventional Oil Shale play in North America. The Bakken Oil Shale produces from fine sandstone and silty sections encased in organic rich Bakken Shale source beds. Bakken Oil Shales are very similar to the Lower Arthur Creek Hot Oil Shales in the Southern Georgina Basin. A TOC of 2 percent is considered to be sufficient for Oil Shale plays and both the Bakken and Arthur Creek Oil Shales have much higher TOC’s. Both shale formations have natural fractures but the limited information from wells in the Southern Georgina Basin suggest that the Arthur Creek Oil Shales may be more highly fractured than the Bakken and, therefore, require less fracture stimulation in the Georgina Basin Arthur Creek shale targets.

Tectonic Setting of the Southern Georgina Basin

The Southern Georgina Basin is part of a large intracratonic basin situated in central Australia filled mainly with Proterozoic, Paleozoic and Mesozoic sediments (Appendix 1, Figures 5 & 6). Cambrian and Ordovician marine and shallow water, near shore sandstones and carbonates (proven productive in the Amadeus Basin to the southwest) are the primary potential reservoir units in the Georgina Basin. A northwest to southeast schematic cross-section illustrates the eastward thickening of the sediments in the Toko Syncline, and identifies the major potential reservoirs and source rocks in the basin (see Appendix 1, Figure 7).

The major tectonic event that impacted the Georgina Basin was the Alice Springs Orogeny (Devonian/Carboniferous). It created significant high-angle basin margin faults such as the Toomba Fault and was responsible for the emplacement of igneous bodies such as the Arunta Block. These igneous bodies were the source of increased heat flow into the hydrocarbon source beds, which ultimately reach the oil maturation level and the generation and migration of oil beginning in the Paleozoic.

Exploration History of the Southern Georgina Basin

Early exploration efforts in the Southern Georgina Basin were based on outcrops, well data, reports of oil shows within water wells, surface gas leaks, gravity and aero-magnetic data and surface structures. Based on a government publication there are approximately twenty nine wells that have been drilled on and in the vicinity of Baraka's lands. It should be noted that the exact well co-ordinates of these twenty nine wells are still to be verified and therefore not all twenty nine wells have been shown on the maps in this report. For this report, AEC on behalf of Baraka has provided Ryder Scott with detailed well data on a number of these wells. In addition there are 750 kilometers of generally poor 2D seismic surveys acquired in 1991 and 233 kilometers of recent, proprietary 2D seismic data acquired by AEC and Texalta in 2009. A re-evaluation undertaken by AEC, of the original 750 kilometers of seismic indicates that all but two (Hunt-1 and MacIntyre-1) of the twenty nine previously drilled wells appear to have been drilled off structure with no closure. Ryder Scott is in general agreement with this conclusion. The Hagen Member in the Hunt-1 well came in 500 meters high to the prognosis at approximately 200 meter vertical depth and was breached and filled with fresh surface water. The MacIntyre-1 well located within Baraka's EP 127 encountered potential pay in the Arthur Creek Shoal. These exploration wells were all drilled between 1962 to 1991 by the Geological Survey of the NT and Pacific Oil and Gas Pty (see Appendix 1, Figure 5). All the wells were drilled with slim-hole mining rigs and were fully cored and logged with limited well-log surveys. Although none of these wells can be classified as discoveries, there were numerous high background gas readings, gas and oil shows, and oil staining in cores in addition to live oil bleeds (see Appendix 1, Figure 8).

The closest other significant hydrocarbon show is located a few kilometers east of the NT-Queensland border in the Ethabuka-1 Well where a gas flow of 6,000 to 7,000 m^3/d (213 Mcf/d to 248 Mcf/d) was recorded from Ordovician Kelly Creek sandstones. However, the deeper primary Cambrian target zones were not penetrated in the well due to mechanical problems. To date prospective Ordovician formations have not been tested on or in the vicinity of the Baraka lands.

Future Exploration Plans by AEC and Baraka

AEC, as operator has signed the required Indigenous Land Access Agreements, with the Native Stake Holders and has permission to conduct operations on EP 127 and EP 128. All necessary government licensing has been received and AEC has put tenders out for bids to a number of drilling contractors in Australia with rigs capable of drilling AEC's proposed wells in the Southern Georgina Basin. As of the date of this report, AEC has executed a drilling contract with Major Drilling Pty Ltd. to supply a rig to under take the proposed drilling in the timeframe required by AEC and Baraka. Initially it is anticipated that a vertical well will cost approximately $2.5 million while a horizontal well will cost approximately $5 million. The cost for drilling vertical and horizontal wells is expected to decrease once a large scale development program is undertaken.

AEC has informed Ryder Scott that assuming additional funding is available that AEC will drill a horizontal well within Baraka's land holdings in the Southern Georginia Basin. The horizontal well will be drilled into the Arthur Creek "Hot Shales" and be stimulated using multi-frac technology. Currently it is anticipated the horizontal well will be a twinning of the MacIntyre-2 well, situated on Baraka's EP 127 (see Appendix 1, Figure 2). Since the "Hot Shale" unconventional prospect is regionally distributed in varying thickness and with varying reservoir characteristics, multiple locations will need to be tested to evaluate the areal extent and productivity of the "Hot Shale" play. Further development may involve the use of multilateral wells, which are expected to lower overall development cost and to increase per well oil production. The conventional targets will be developed either with vertical or horizontal/multi-lateral wells depending on their initial productivity 3D seismic may be employed to aid development drilling, and further 2D seismic may be acquired so as to expand the basin understanding and conventional structural prospects

Principle Source Rocks in the Southern Georgina Basin

The primary proven source rocks in the Southern Georgina Basin are the organic rich "Hot Shale" of the lower portion of the Arthur Creek Formation (Appendix 1, Figures 6 & 8). These shales range in maturity from oil-mature to dry gas mature/over mature. However, over the majority of Baraka's EPs, the source beds are within the oil window (see Appendix 1, Figure 9). TOC values in the Arthur Creek "Hot Shale" reach 10 percent or more and average over 5 percent. Based on work done by the Siberian Institute of Petroleum Geology, over 40 billion tonnes (280 billion barrels) may have been expelled from these source rocks in the vicinity of Baraka's lands.

Potential Reservoirs (<u>Conventional</u>)

Two conventional potential oil reservoirs have been evaluated in this report: Upper Arthur Creek Hagen Member carbonate reservoirs and Upper Arthur Creek Arthur Creek Shoal reservoirs. We have assigned unrisked undiscovered OOIP and prospective (recoverable) oil resources to all these reservoirs in this report (see Appendix 1, Figure 6).

The Hagen Member reservoir is best developed in the Western part of the Georgina basin, within the Dulcie syncline where the gross reservoir thickness can reach up to 70 meters. The reservoir consists of peloidal grainstone dolostones with fenestral/vuggy dissolution porosity type with poor to excellent pore connectivity. In Randall-1, 13.7bls of salty (12,589mg/l) sulfurous water was recovered. Core analysis showed permeability up to 3 darcies and porosities of 8 to 14 percent.

The Arthur Creek Shoal reservoir is within the Upper Unit of the Middle Cambrian Arthur Creek Formation. It consists of shallow water deposits consisting of peloid, intraclasts and dolograinstones capped by recrystallised dolostones. In the MacIntyre-1 Well, the reservoir has a gross thickness of 7 meters with permeability of up to1.2 darcies and porosity of 14.6 percent measured from the core.

There are likely a number of additional potential conventional reservoirs in the basin, an example of which are Ordovician sandstones and dolostones, with up to 11 percent porosity and 234 millidarcies of permeability. However the current limited well control and poor seismic coverage precludes assigning resource volumes to more than the four conventional reservoirs described above.

Potential Reservoirs (<u>Unconventional</u>)

The Lower Arthur Creek organic rich “Hot Shale” is a potentially very large unconventional Shale Oil play in the Georgina Basin with world class TOC values averaging over 5 percent in the shale intervals, and multiple potential oil reservoirs in the inter-bedded fine sands, silts and porous carbonate zones. In comparison, the proven Cambrian source rocks in the Russian platform have TOCs ranging from 0.47% to 1.37% and the Arabian Peninsula source rocks have average TOCs of 4.1%. Secondary potential unconventional reservoirs are dolomite and limestone zones within organic rich shales (2% TOC) in the Upper Arthur Creek Formation.

<u>Seismic Quality and Reservoir Mapping</u>

The areal extent of the conventional seismic anomalies identified on AEC and Texalta proprietary 2009 seismic lines and on the old seismic are considered as representative of the size and type of targets likely present in the basin (see Appendix 1, Figure 2). Considerable additional seismic lines will be necessary to better understand the hydrocarbon potential of Baraka’s EPs. Ryder Scott reinterpreted some of the old pre 2009 seismic and identified a large Hagen Member closed structure in the vicinity of the Randall-1 well (see Appendix 1, Figures 2 & 10).

<u>Probabilistic Analysis</u>

A probabilistic approach to estimating undiscovered oil and gas resources is considered to be the most appropriate methodology to use for projects such as this, where a great deal of uncertainty exists in the reservoir parameters. The probabilistic method utilizes estimates of the distributions of individual uncertain reservoir parameters as input parameters into a probabilistic model. Using a multiple iterative approach an expected probability distribution for potential resources is calculated. Estimates of Minimum, Most Likely and Maximum distribution values for the various reservoir parameters are used as input parameters into the Crystal Ball software to perform the calculations.

<u>CONVENTIONAL RESERVOIRS</u>

Two conventional reservoirs have been assigned resource volumes in this report; the Hagen Member, and Arthur Creek Shoal. Based on the available information including the interpreted burial history of the Southern Georgina Basin, we anticipate that all two reservoirs could contain oil.

<u>Probabilistic Modeling Input Parameters</u>

As mentioned previously, there is very limited well control within the South Georgina Basin considering its size. The reservoir parameters used in this 2010 report for the conventional resource calculations were based on our evaluation of the two conventional reservoirs in the nine previously drilled wells (see Appendix 2, Table 1). Porosity, gross interval, and net to gross ratio were estimated based on our analysis of the logs and core analysis from the nine wells. Water saturation and oil recovery factors represent reasonable ranges for these parameters for the reservoir types identified. Areas under closure were estimated from seismically derived maps and represent the most likely area of the structure.

The reservoir input parameters for the conventional reservoirs, which were used in the Crystal Ball calculations are summarized in the following Tables 1A and 2A below. Triangular distributions were assumed for all of the input reservoir parameters.

Table 1A

Summary Of Reservoir Parameters For Probabilistic Analysis, Hagen Member

Parameter	*Minimum*	*Most Likely*	*Maximum*
Porosity, (%)	*4*	*9*	*14*
Gross Interval (feet)	*50*	*98*	*196*
Net/Gross (fraction)	*0.22*	*0.36*	*0.55*
Fill Factor, (fraction)	*1*	*1*	*1*
Oil Saturation, (%)	*70*	*75*	*80*
Oil Recovery Factor, (%)	*10*	*15*	*25*

Table 2A

Summary Of Reservoir Parameters For Probabilistic Analysis, Arthur Creek Shoal

Parameter	*Minimum*	*Most Likely*	*Maximum*
Porosity, (%)	*4*	*9*	*15*
Gross Interval (feet)	*16*	*35*	*60*
Net/Gross (fraction)	*0.25*	*0.5*	*0.7*
Fill Factor, (fraction)	*1*	*1*	*1*
Oil Saturation, (%)	*70*	*75*	*80*
Oil Recovery Factor, (%)	*10*	*15*	*25*

Area of Closure on the Seismic Structures

The aerial extent of the Hagen Member and the Arthur Creek Shoal were estimated from selected old pre (2009) seismic and from well logs. The aerial extent of the HA Hagen Prospect was estimated from the old seismic (see Appendix 1, Figures 2, 10 & 11). The Hagen Member has very poor seismic definition and therefore the aerial extent was chosen arbitrarily based on our current knowledge of the basin. The aerial extent of the Sh_Mctyr Arthur Creek Shoal prospect was estimated from a single old seismic line run through the MacIntyre-1 well (see Appendix 1, Figures 2 & 13). The aerial extent was assumed to be a circle with the diameter shown on the seismic line.

The areas for all of the conventional reservoirs were estimated from the time structure maps and were assumed to represent the most likely size of each structure defined by seismic and the most likely area of structural closure within the lowest closed time contour. The maximum area for each prospect was estimated upwards by 15 percent and the minimum area was estimated downwards by 15 percent for all structures.

Probabilistic Unrisked Undiscovered OOIP and Prospective Oil Resource Estimates

The following Tables 1B and 2B summarizes the probabilistic unrisked estimation of undiscovered OOIP (oil volumes in-place) and the prospective resources (recoverable oil volumes) for the two conventional reservoirs evaluated in this report in three mapped closures. It should be noted that the uncertainty in these estimates is very high. The detailed tables present the undiscovered OOIP and prospective resource (recoverable oil volume) estimates by individual structure. The oil volumes are presented in millions of barrels (MMbls).

Table 1B (Oil Volumes)
Unrisked Estimates of Undiscovered OOIP and Prospective Recoverable Oil Resources in the
Hagen
Southern Georgina Basin – Northern Territory, Australia
As of November 1, 2010

Prospect	Unrisked Undiscovered OOIP (MMbls)			Unrisked Prospective (Recoverable) Oil Resources (MMbls)		
	Low	Best	High	Low	Best	High
H-A	125.85	221.59	374.02	12.70	24.77	47.04

***Baraka's interest in the above Prospect H-A oil volumes is 25%**

Table 2B (Oil Volumes)
Unrisked Estimates of Undiscovered OOIP and Prospective Recoverable Oil Resources in the
Arthur Creek Shoal
Southern Georgina Basin – Northern Territory, Australia
As of November 1, 2010

Prospect	Unrisked Undiscovered OOIP (MMbls)			Unrisked Prospective (Recoverable) Oil Resources (MMbls)		
	Low	Best	High	Low	Best	High
Sh_Mctyr	**6.5**	**11.6**	**19.4**	**0.7**	**1.3**	**1.3**
Total	**6.5**	**11.6**	**19.4**	**0.7**	**1.3**	**1.3**

***Baraka's interest in the above Prospect Arthur Creek Shoal oil volumes is 25%**

CONVENTIONAL SUMMARY TABLE 3B (Oil Volumes)
Unrisked Estimates of Undiscovered OOIP and Prospective Recoverable Oil Resources in the
Hagen and Arthur Creek Shoal
Southern Georgina Basin – Northern Territory, Australia
As of November 1, 2010

Prospect	Unrisked Undiscovered OOIP (MMbls)			Unrisked Prospective (Recoverable) Oil Resources (MMbls)		
	Low	Best	High	Low	Best	High
H-A	125.85	221.59	374.02	12.70	24.77	47.04
Sh_Mctyr	6.5	11.6	19.4	0.7	1.3	1.3
Total	**132.35**	**233.19**	**393.42**	**13.40**	**26.07**	**48.34**

***Baraka's interests in the above Prospects H-A and Sh_Mctyr oil volumes is 25%**

Geological Risk Assessment, Conventional Resources)

The total geologic risk is an estimate of the chance that oil will be discovered in a given structure. The total geologic risk associated with the above unrisked undiscovered OOIP resource estimates is based on four principle geological risk factors:

i. Trap
ii. Timing and Migration
iii. Reservoir
iv. Source

The total geologic risk is expressed as a fraction and ranges from a minimum risk of 1.0 (100% chance of oil discovery), to 0.0 (0% chance of oil discovery)**.** With respect to the four principal risk factors, a higher value indicates less risk.

Trap Risk

Trap risk is defined as the probability that adequate vertical and lateral seals exist which could confine hydrocarbons within adjacent reservoir rock. For the conventional reservoirs, the trap risk is directly proportional to the confidence of the structure identified on seismic as well as evidence of four-way closures. The quality of the seismic is poor and thus the trap risk is relatively high. The Hagen and Arthur Creek Shoal reservoirs are assigned a trap risk of 0.7.

Timing and Migration Risk

Timing and migration risk is the probability that a source rock expelled oil or gas after the reservoir and trap were formed and that a flow path existed between source and reservoir. A timing and migration risk of 0.5 was assigned for both potential conventional reservoirs for all structures. Due to the lack of definitive data, there is substantial uncertainty as to whether or not migration occurred before or after trap formations.

Reservoir Risk

Reservoir risk is defined as the probability that a lithology exists with sufficient porosity, permeability and continuity to contain moveable hydrocarbons. For the two conventional reservoirs in the Southern Georgina Basin the limited drilling and seismic data suggests that the reservoirs are present in the identified structures. Therefore a reservoir risk of 0.7 is assigned to all prospects.

Source Risk

Source risk is defined as the probability that a lithology exists with sufficient quantity and quality of thermally mature organic matter to have expelled oil or gas which could feasibly have migrated to the reservoir. A source risk of 0.9 has been assigned to all play types within the Southern Georgina Basin. Oil shows are numerous in core samples and well tests in the Southern Georgina Basin and there are several potential source beds with high TOC values in the basin.

Total Geological Risk

The total geologic risk by structure for each potential conventional reservoir taking is defined as:

(Total geologic risk = (trap risk) x (reservoir risk) x (source risk) x (timing and migration risk)

The total geologic risk for the Hagen and the Arthur Creek Shoal prospects is 0.22.

UNCONVENTIONAL RESERVOIRS

The organic rich "Hot Shale" within the Lower Arthur Creek Formation has been identified as a potential unconventional shale oil reservoir in the Southern Georgina Basin. The intergranular (free porosity) within the sandier and silty intervals within of the shale are the main oil reservoirs.

Probabilistic Modeling Input Parameters -Hot Shale

In this report the gross thickness of the Hot Shale pay interval was estimated from petrophysical interpretations of nine wells on and in the vicinity of Baraka's two EPs plus information from thirteen additional wells in Government Publications (see Appendix 2, Table 2). A gross pay map of only the Hot Shale interval was prepared based on the petrophysical interpretation of the above mentioned ten wells and aided by a re-interpretation of the 2009 seismic (see Appendix 1, Figure 13). Triangular distributions were assumed for all the input reservoir parameters. The distribution of the other input parameters such as net to gross pay, porosity and water saturation were also estimated from the detailed petrophysical interpretation of the twelve wells. The distribution of input parameters for the Lower Arthur Creek Oil Shale, which were used as inputs into Crystal Ball are summarized in Table 3A below.

Table 3A
Summary Of Reservoir Parameters For Probabilistic Analysis, Arthur Creek "Hot Shale"

Parameter	*Minimum*	*Most Likely*	*Maximum*
Porosity, (%)	*8*	*10*	*12*
Gross Interval, (Acre_feet)	*560,273,234.00*	*560,273,234.00*	*560,273,234.00*
Net/Gross (fraction)	*0.1*	*0.125*	*0.2*
Oil Saturation – expected (%)	*75*	*80*	*85*
Oil Recovery Factor, (%)	*5*	*10*	*15*

Probabilistic Undiscovered Shale Oil Resource Estimates

Lower Arthur Creek "Hot Shale"

The following Table 3B summarizes the probabilistic unrisked estimation of undiscovered OOIP (oil volumes in-place) and the prospective resources (recoverable oil volumes) for the Arthur Creek Hot Shale. The oil volumes are given in billions of barrels (BBbls).

Table 3B (Oil Volumes) Unrisked Estimates of Undiscovered OOIP and Prospective Recoverable Oil Resources in the Lower Arthur Creek "Hot Shale" Southern Georgina Basin – Northern Territory, Australia						
As of November 1, 2010						
Prospect	**Unrisked Undiscovered OOIP (BBbls)**			**Unrisked Prospective (Recoverable) Oil Resources (BBbls)**		
	Low	**Best**	**High**	**Low**	**Best**	**High**
EP 127	19.789	27.715	37.190	1.753	2.723	4.009
EP 128	34.969	48.934	65.718	3.097	4.812	7.084
Total EP 127, EP 128	**54.758**	**76.649**	**102.908**	**4.850**	**7.535**	**11.093**

Geological Risk Assessment, Unconventional Resources

In this report Ryder Scott has not attempted to quantify the geological risk for the potential unconventional undiscovered oil resources in the Lower Arthur Creek Hot Oil Shale. The major difference between undiscovered conventional and unconventional prospects is that in conventional plays the biggest risk is usually whether or not the resources will be discovered, where as in the case of unconventional plays the biggest risk is usually whether it will be technically and economically viable to produce the resources.

Additionally, there is no history of hydrocarbon production and very little data in general, from unconventional Shale Oil deposits in the Southern Georgina Basin or elsewhere in Australia. At the present stage of exploration in the Southern Georgina Basin, it is our opinion that Baraka's unconventional resource play must be considered as being very high risk.

General

It should be noted that the oil volumes presented in this report are estimates only and should not be construed as being exact quantities. Southern Georgina Basin represents a legitimate high risk exploration play with the potential for discovery of significant oil deposits. The Southern Georgina Basin is at an early stage of exploration, which by North American standards would be considered very under explored. There is no assurance that any of these resources will be discovered and if discovered they may not be economic to produce.

Estimates of unrisked undiscovered OOIP and unrisked prospective resources presented herein are based upon a review of the data provided by AEC on behalf of Baraka. We have not made any field examination of the property, as it was deemed that an on-site visit would not provide any significant additional data pertinent to the evaluation of the resources.

No consideration was given in this report to potential environmental liabilities which may exist, nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices. AEC have informed us that they have provided us all of the geological and engineering data, reports and other data that was available for this investigation. The data received from AEC were accepted as represented without further investigation.

Neither we nor any of our employees have any interest in the subject property and neither the employment to make this study nor the compensation is contingent upon our estimates of resources for the subject property.

This report was prepared for the exclusive use and sole benefit of Baraka Petroleum Limited and may not be put to other use without our prior written consent. We reserve the right to revise any opinions provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided is found to be erroneous.

Very truly yours,

RYDER SCOTT COMPANY-CANADA

Linda Echikh, P. Geol.
Geologist

Fred J. Dewis, P. Geol.
Vice President, Geoscience

PERMIT TO PRACTICE
RYDER SCOTT COMPANY
Signature
Date December 5, 2010
PERMIT NUMBER: P 6092
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

CERTIFICATE OF QUALIFICATION

I, FREDERICK JOHN DEWIS, Professional Geologist, in the province of Alberta, Canada, HEREBY CERTIFY:

1. THAT I am a registered Professional Geologist in the province of Alberta and reside in the city of Calgary, Alberta.

2. THAT I graduated from Carleton University with Honors in Geology with a Bachelor of Science degree in 1969 and received a Master of Science degree in Geology from the University of Calgary in 1971.

3. THAT I have been employed in the petroleum industry for approximately 41 years since graduation. During the time of employment I have been directly involved in reservoir geology and petrophysical analysis.

4. THAT I am presently employed by Ryder Scott Company which prepared an evaluation effective November 1, 2010 for Baraka Petroleum Limited.

5. THAT a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, and the files of Baraka Petroleum Limited.

6. THAT I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Baraka Petroleum Limited or its affiliated companies.

Frederick J. Dewis, P.Geol.

December 5, 2010

CERTIFICATE OF QUALIFICATION

I, LINDA ECHIKH, Professional Geologist, in the province of Alberta, Canada, HEREBY CERTIFY:

1. THAT I am a registered Professional Geologist in the province of Alberta and reside in the city of Calgary, Alberta.

2. THAT I graduated from the Algerian Petroleum Institute with a Bachelor of Science degree in Petroleum Geology in 1992.

3. THAT I have been employed in the petroleum industry for approximately 12 years since graduation. During the time of employment I have been directly involved in reservoir geology, petrophysical analysis, exploration geology and property evaluation.

4. THAT I am presently employed by Ryder Scott Company which prepared an evaluation effective November 1, 2010 for Baraka Petroleum Limited.

5. THAT a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, and the files of Baraka Petroleum Limited.

6. THAT I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Baraka Petroleum Limited or its affiliated companies.

Linda Echikh, P.Geol.

PROFESSIONAL GEOLOGIST ALBERTA
LINDA ECHIKH

December 5, 2010

APPENDIX 1

Southern Georgina Basin Australia

FIGURE 1 NOVEMBER 29, 2010

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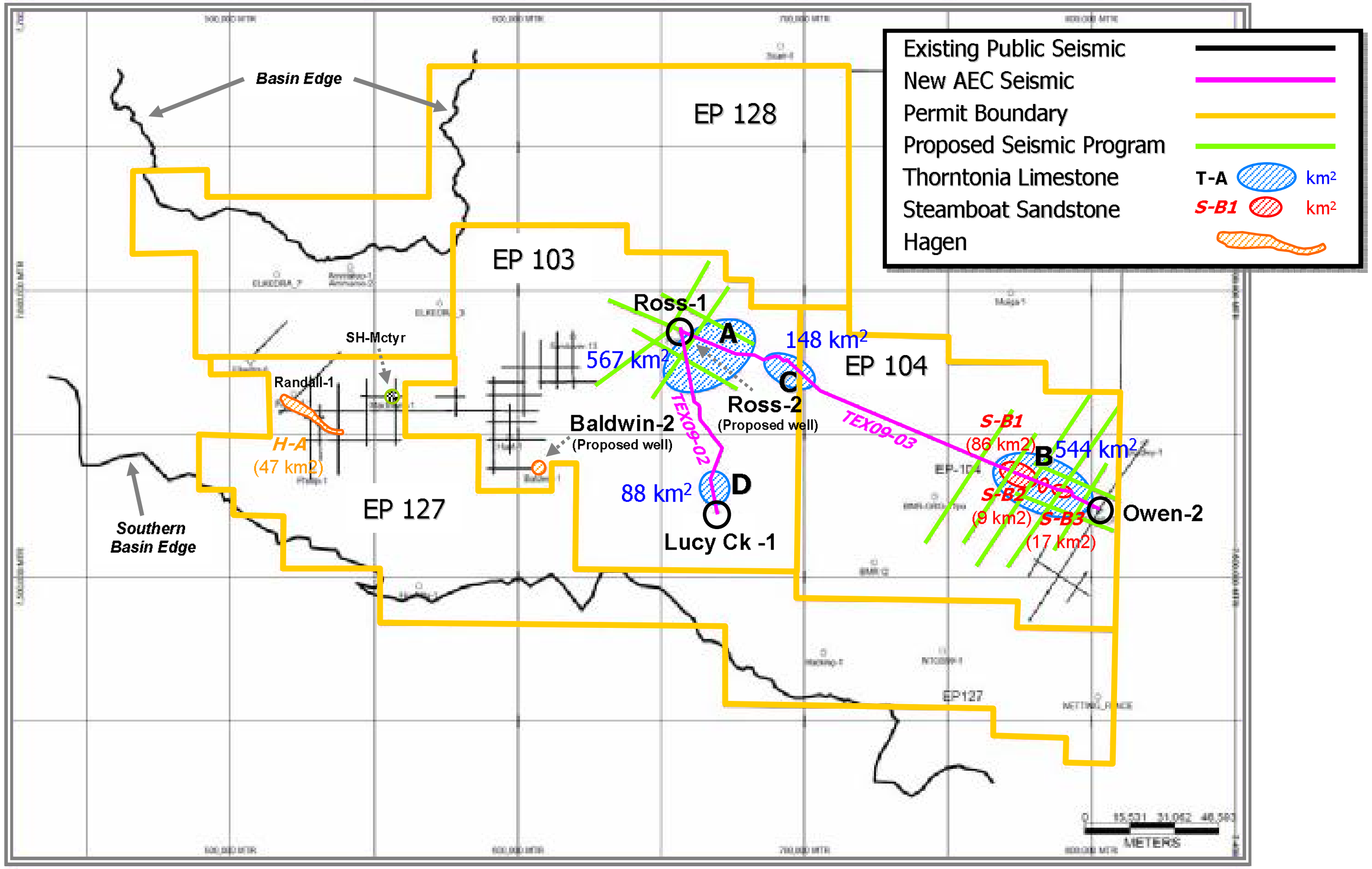
Base Map Showing Hagen, Steamboat, Arthur Creek Shoal and Thorntonia Structures



Large structures are seen at the Steamboat and Thorntonia. Closure cannot be demonstrated with the current sparse control, but more detailed seismic will certainly isolate many closed structures.

FIGURE 2

NOVEMBER 29, 2010

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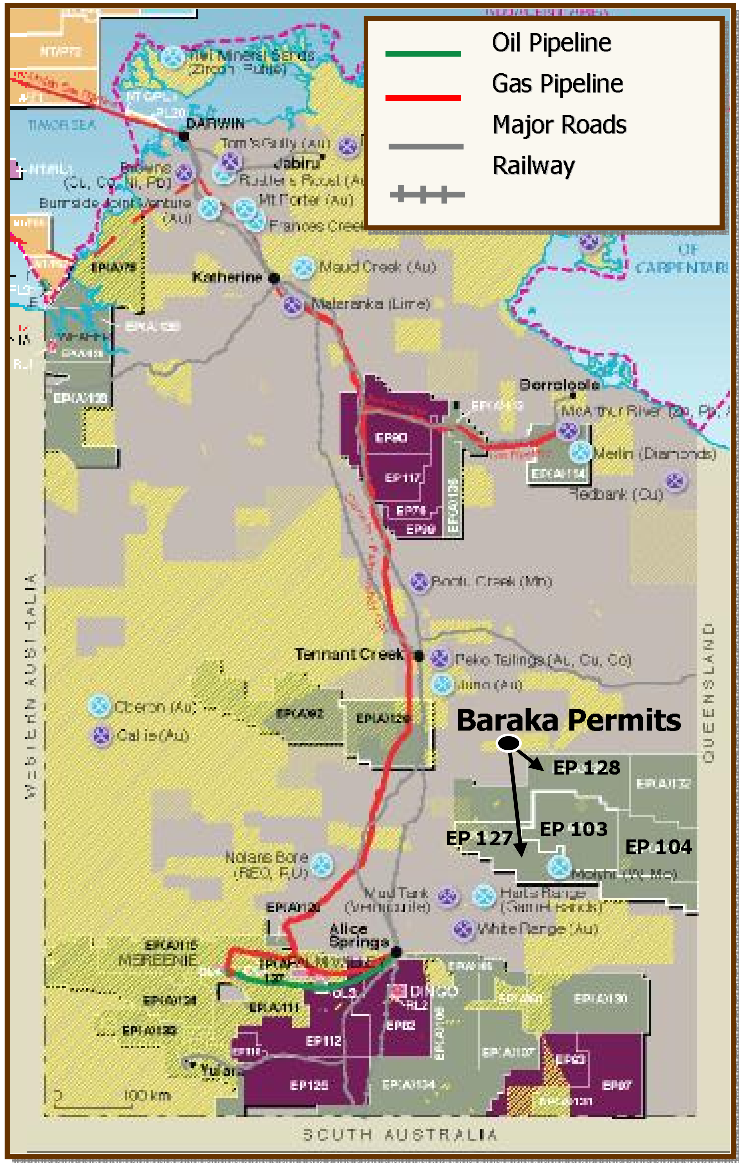
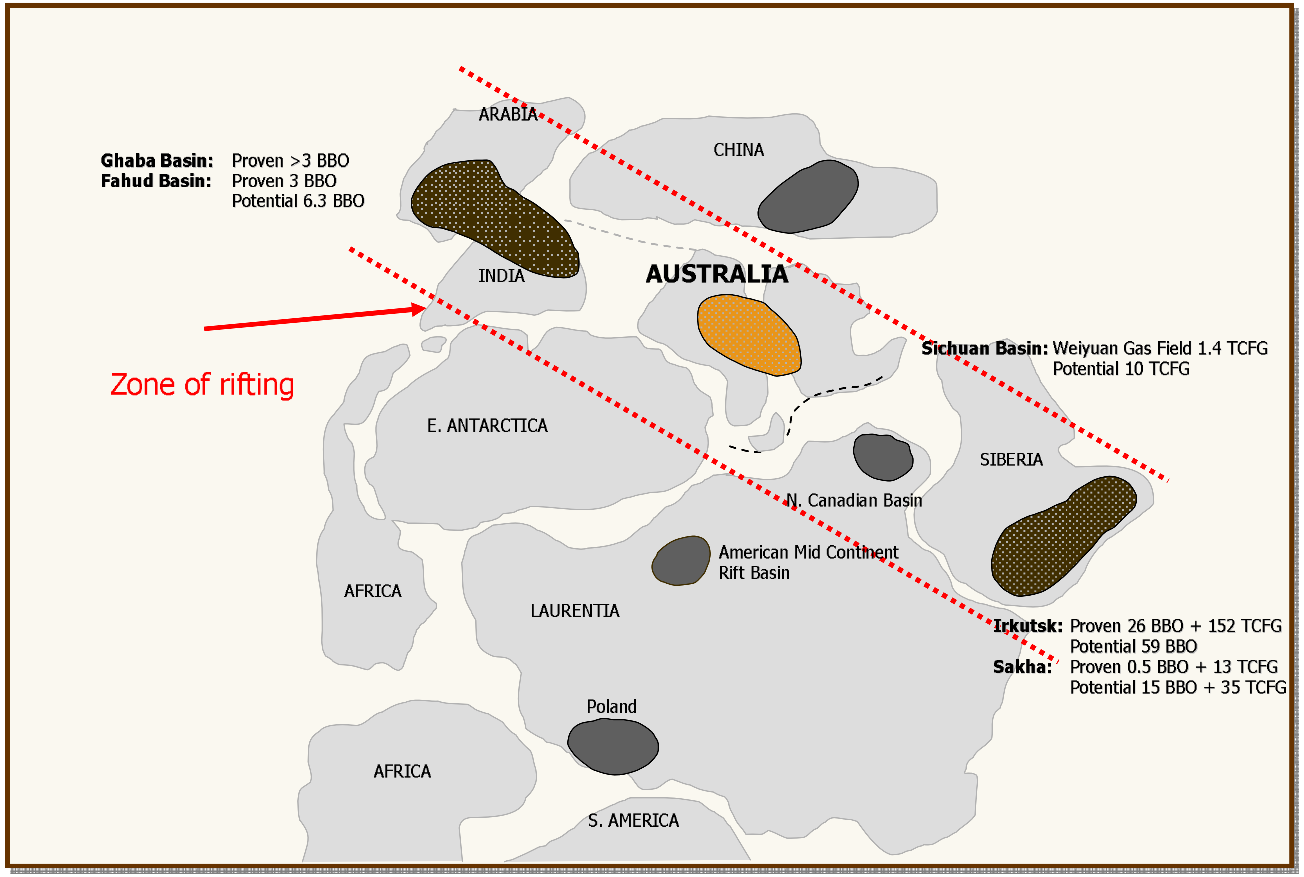


Southern Georgina Basin Lands & Infrastructure

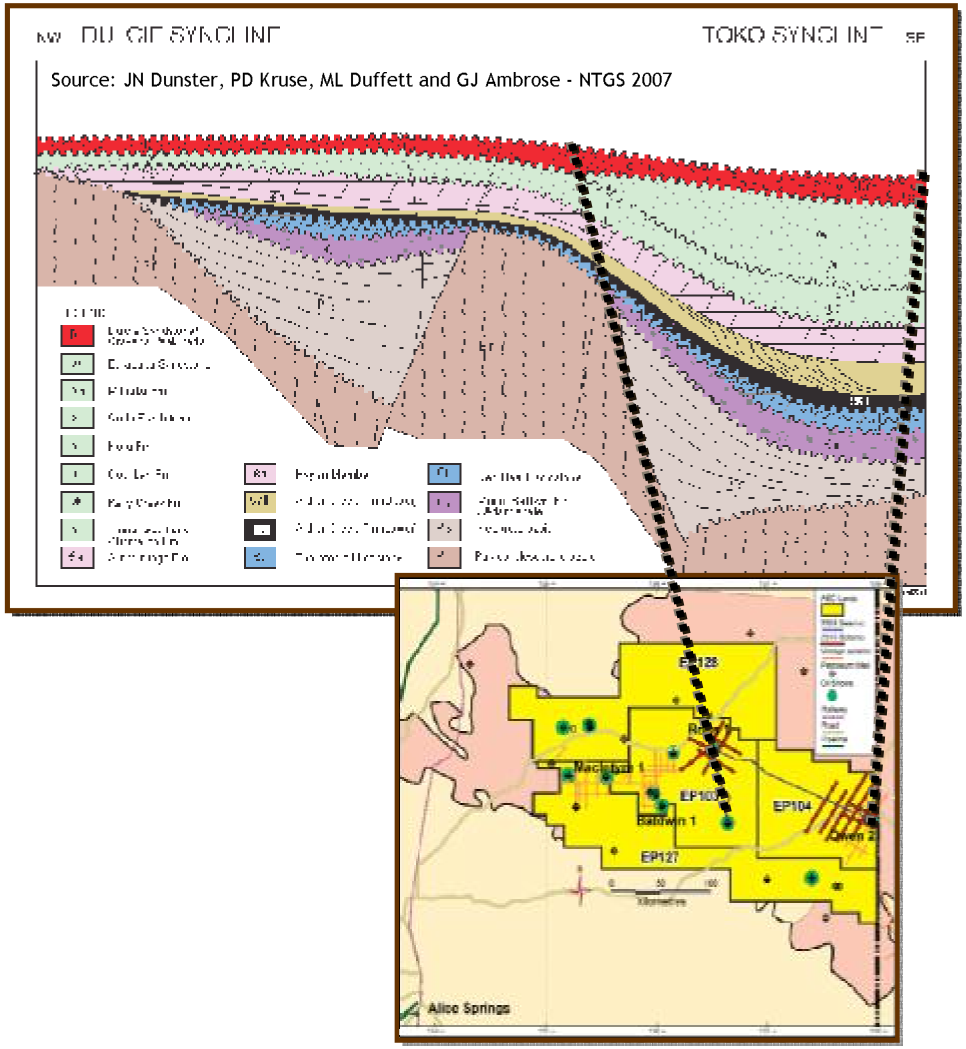
- Lands close to Alice Springs
- Accessible to oil and gas infrastructure and pipelines
- Near major highways
- Minor roads intersect EP 103, 104, 127 & 128 and connect to major roads
- Railroad access

History – Rodinia Supercontinent



Source: PIRSA 1998
U.S. Geological Survey Bulletin

Stratigraphic Diagram (Southern Georgina Basin)



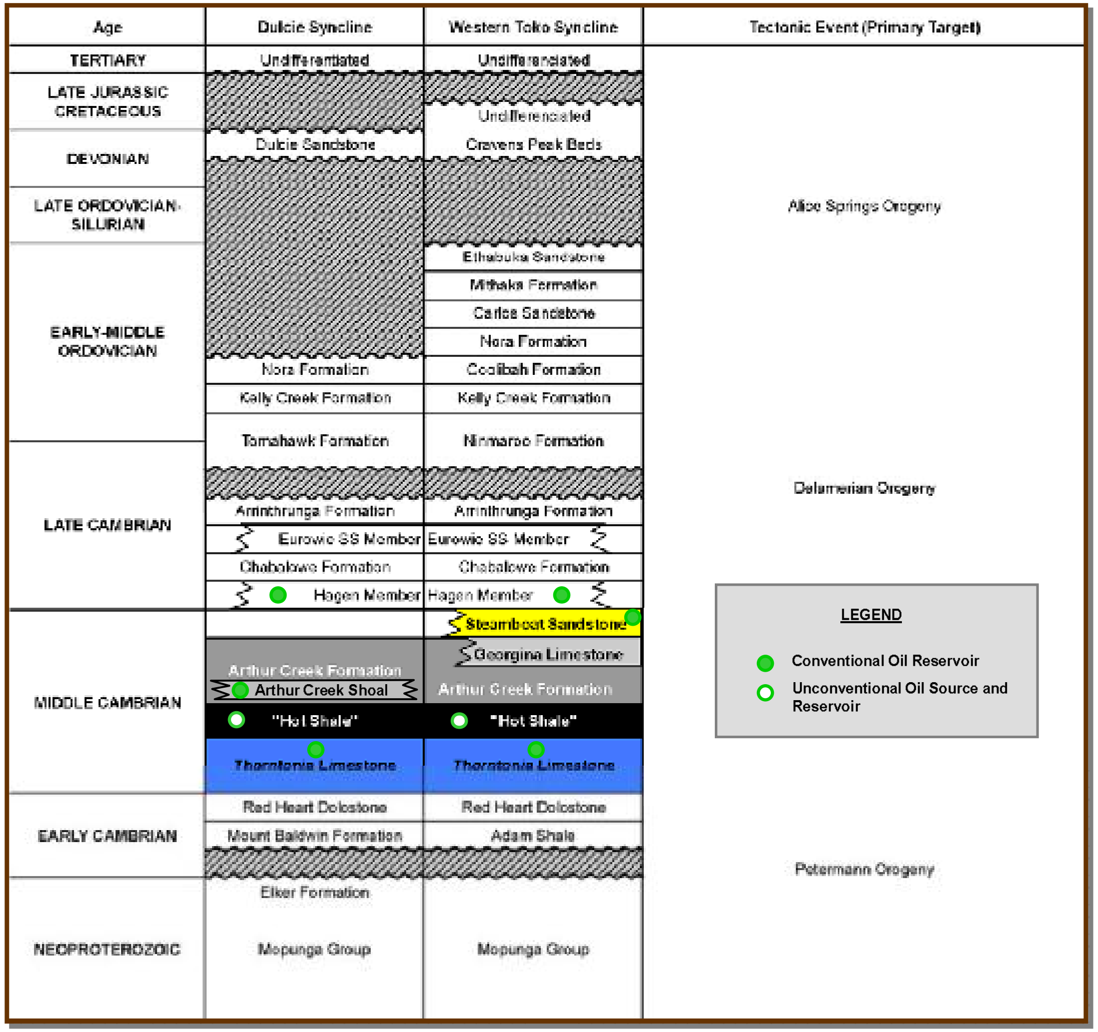
Toko Syncline

- Majority of PFC lands are in this region
- The most prospective region
- Fewest wells drilled to date
- Contains oil mature rocks
- Only region with Steamboat Sandstone
- Arthur Creek Shale is thickest

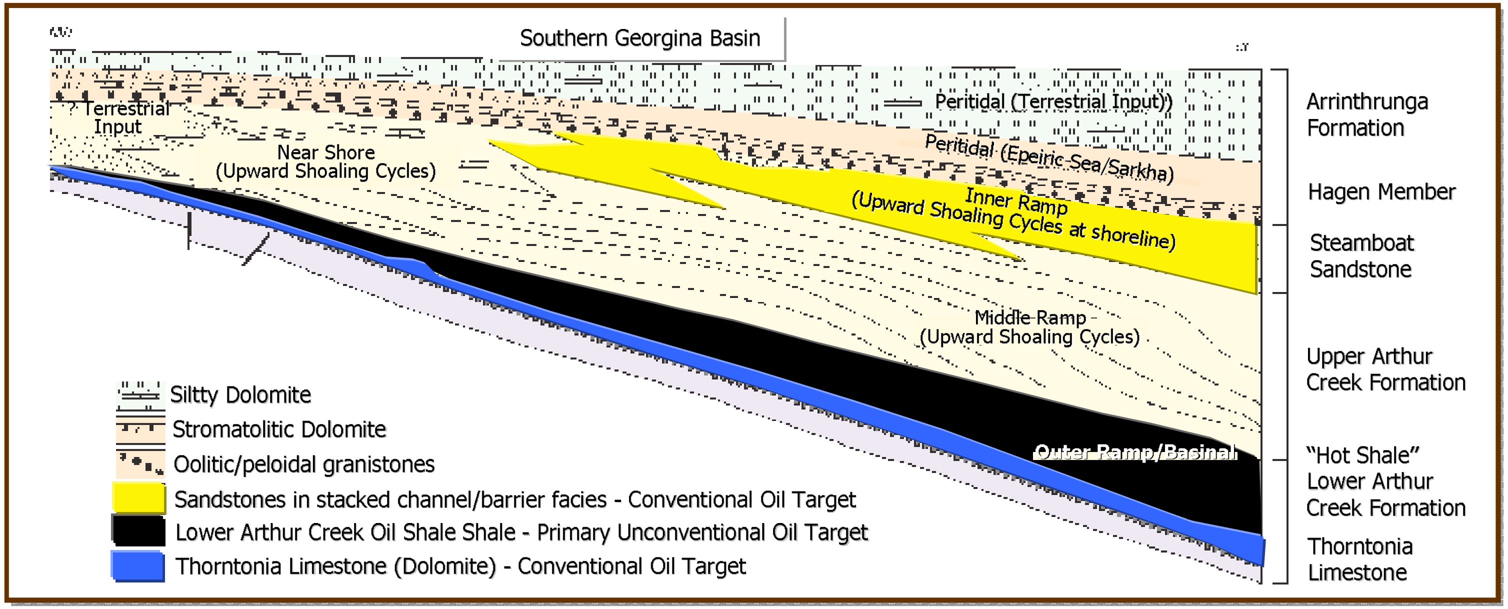
Dulcie Syncline

- Mostly gas mature or over-mature
- Most wells drilled to date

Cambrian Petroleum System



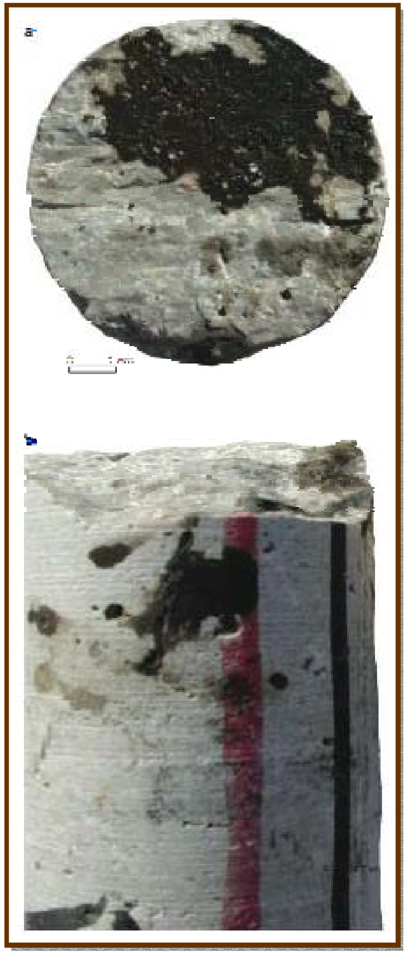
Schematic Cross-Section of Toko Syncline



Source: JN Dunster, PD Kruse, ML Duffett1 and GJ Ambrose - Geology and resource potential of the southern Georgina Basin

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Well Cores



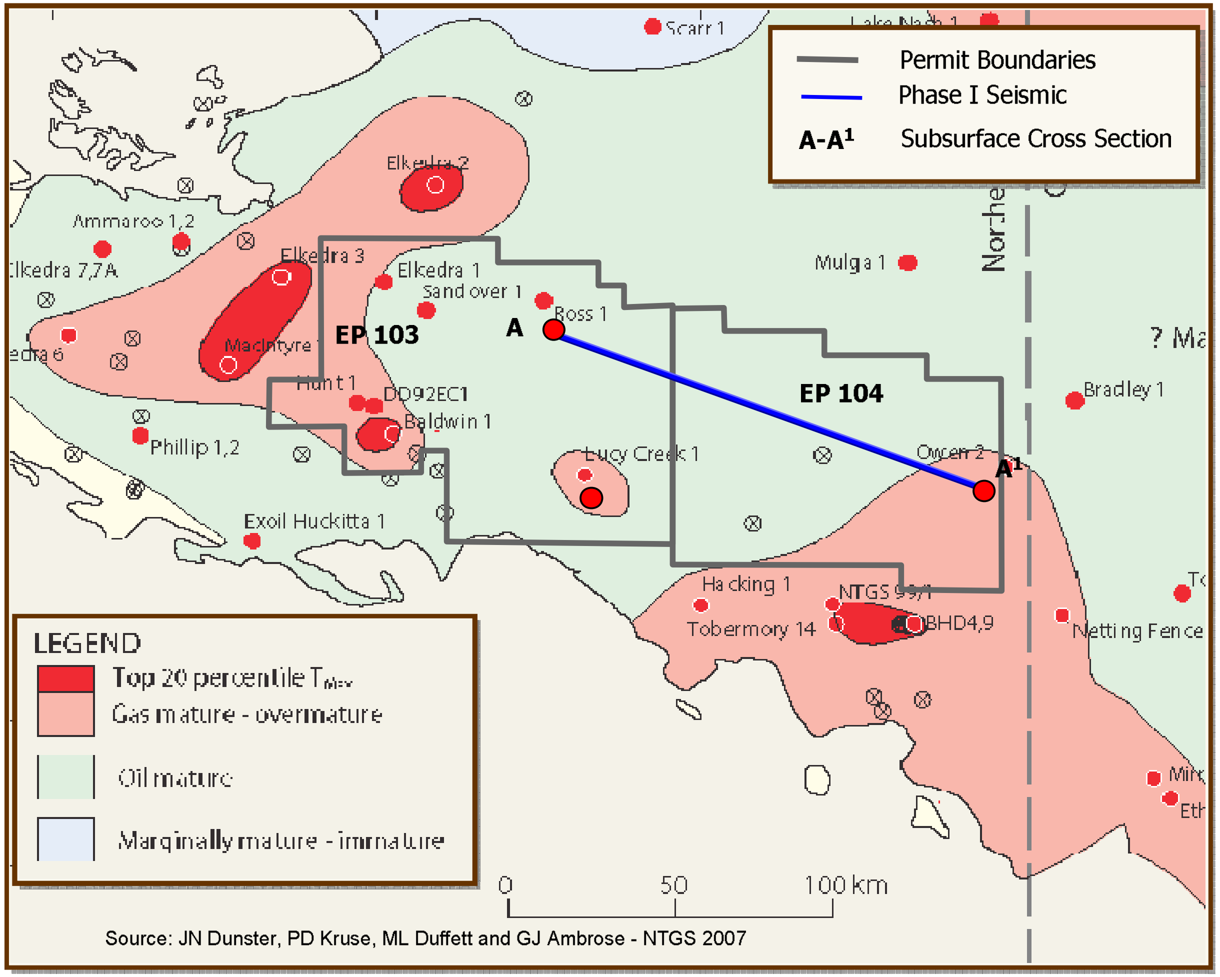
Oil shows in Thorntonia Limestone. 935 m depth in Ross 1.

Vugular porosity associated with karsted Thorntonia Limestone dolostone Ross-1.

Black laminated, organic-rich shale (potential source rock) of the basal Arthur Creek Formation ("Hot Shale") overlying Thorntonia Limestone from Ross-1 (934 m)

Vuggy porosity in upper Arthur Creek Formation, 878-880 m depth Owen 2

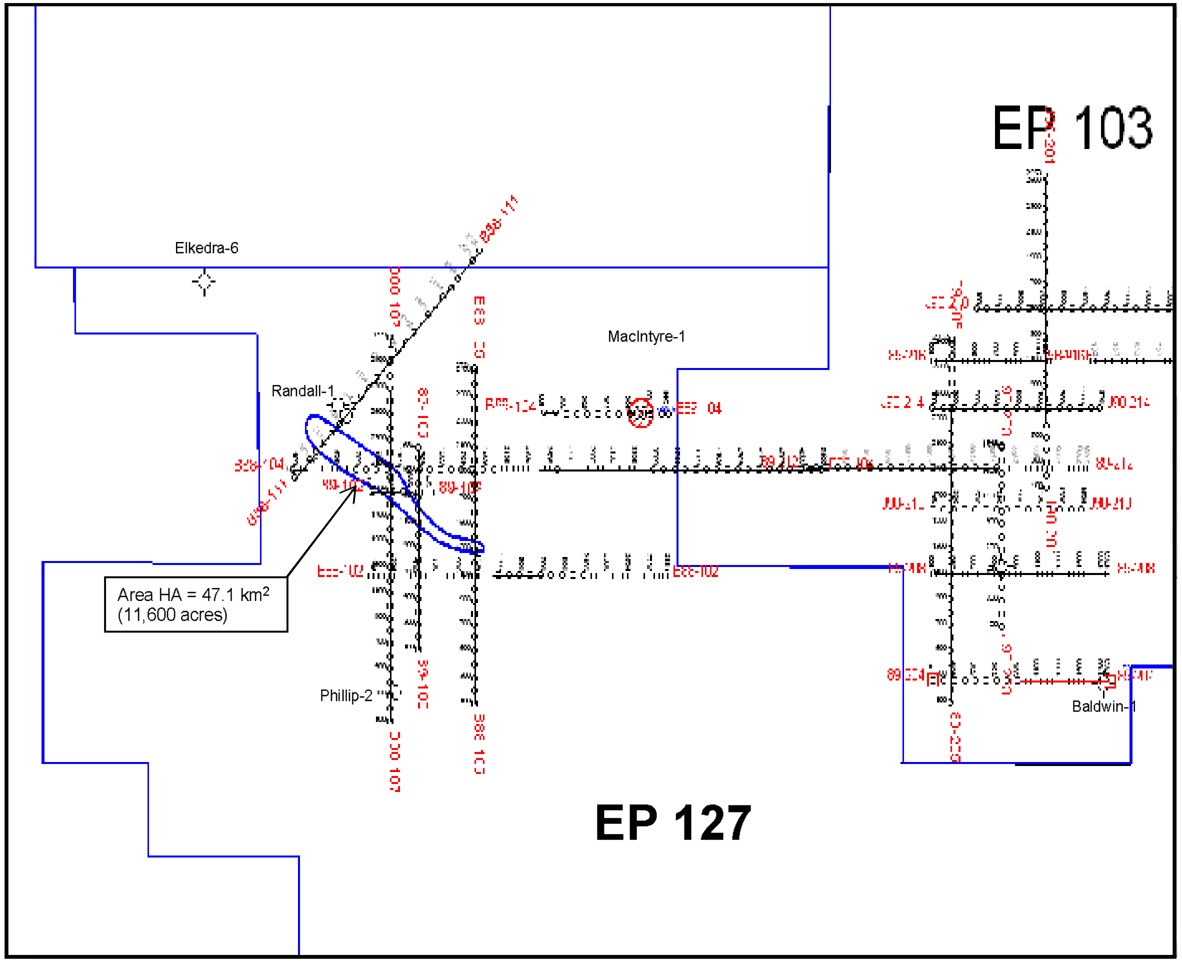
Southern Georgina Basin, NT Maturation Levels



Australia Energy Corp.

Georgina Basin
Australia

Hagen Member
Structural Closure
Area of closure on
Prospect HA



Boyd | PetroSearch

RYDER SCOTT COMPANY
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FIGURE 10

NOVEMBER 29, 2010

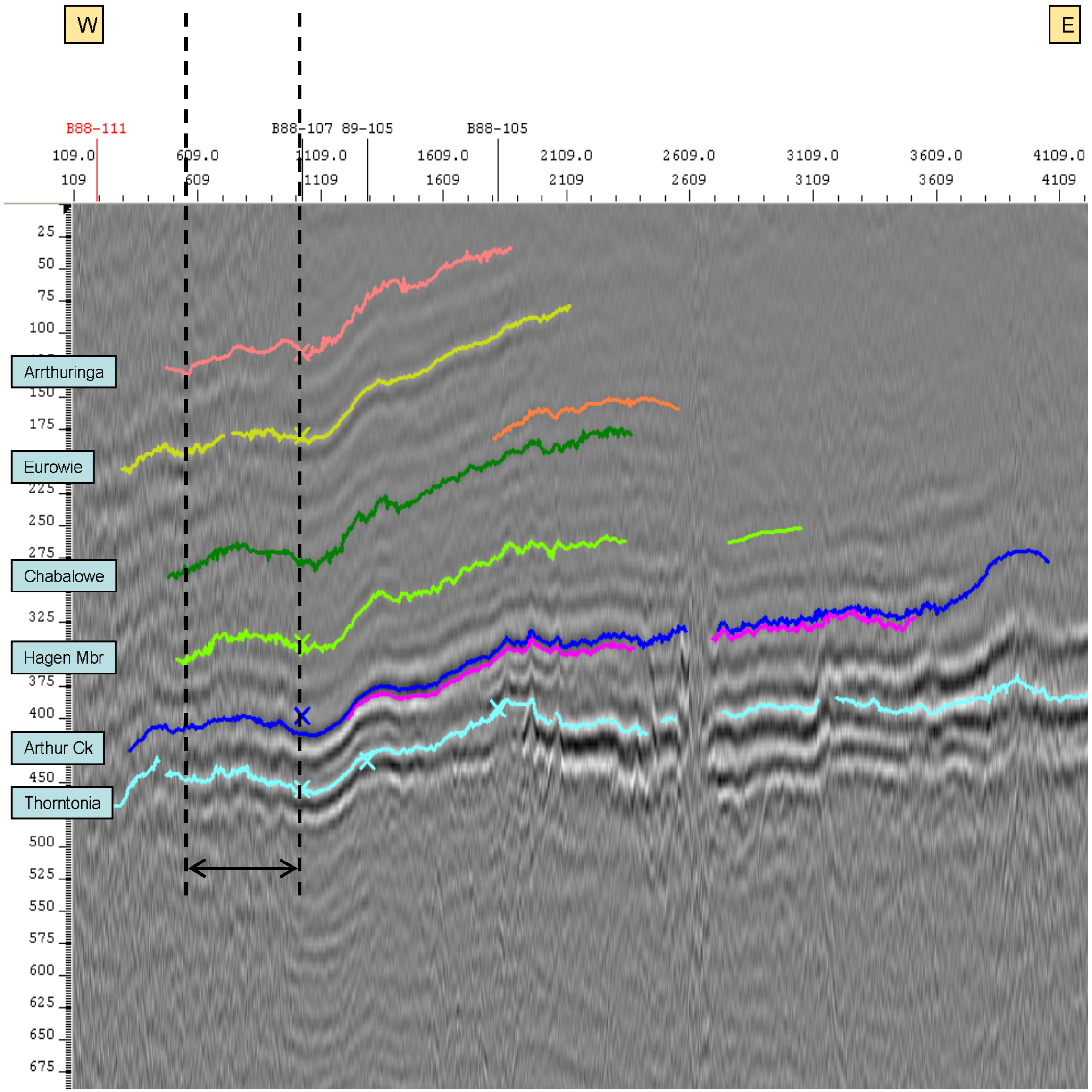
Australia Energy Corp.

Georgina Basin
Australia

West end of
Line B88-104

Hagen Member
Prospect HA

Beds appear to be thinning to the W



Boyd | PetroSearch

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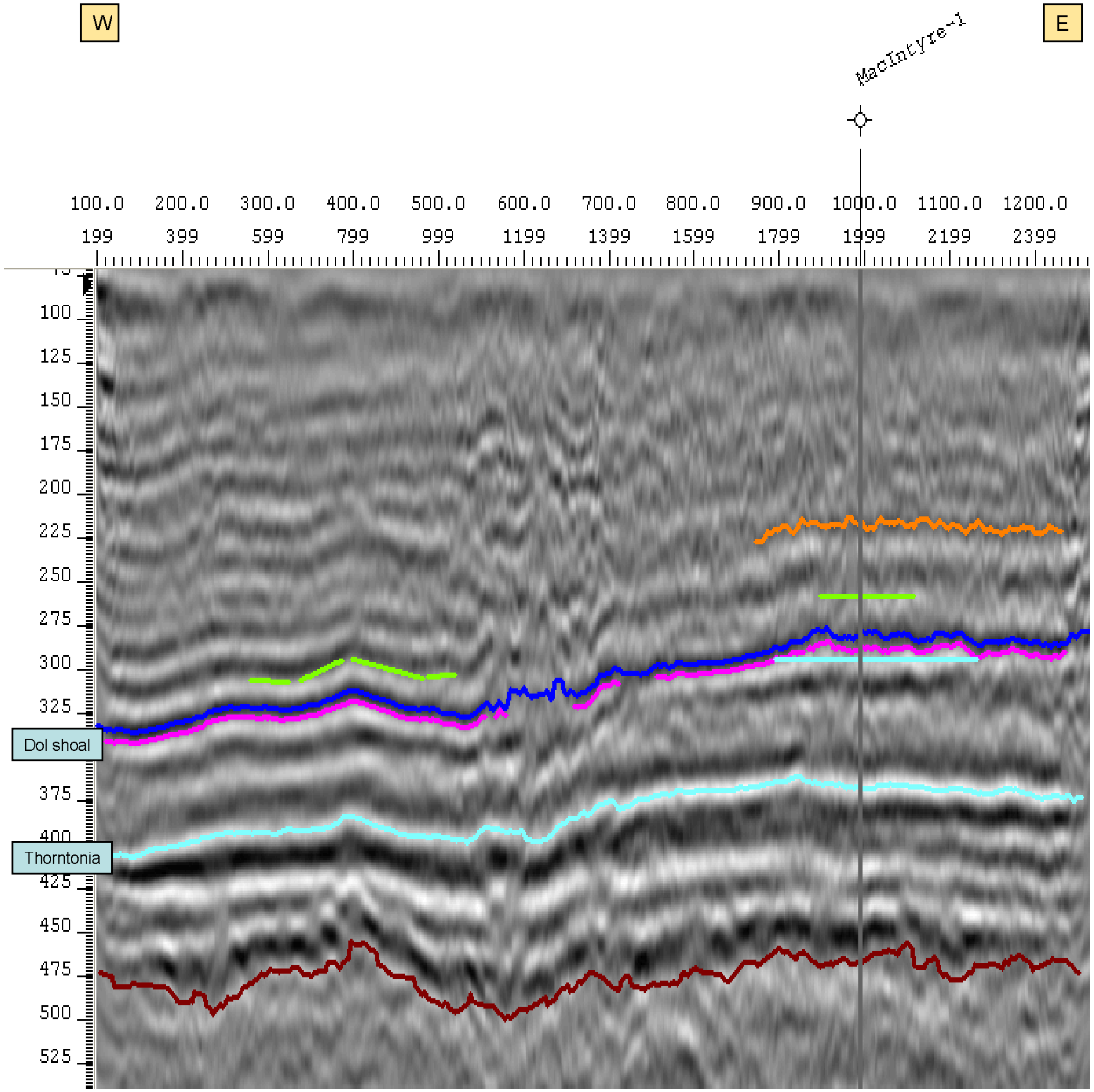
FIGURE 11

NOVEMBER 29, 2010



Australia Energy Corp.

Georgina Basin
Australia

All of
Line B89-104

Arthur Creek shoal

SH-Mctyr prospect

Seismic definition is poor, but there is clearly a structural closure at the level of the dolomitic shoal. Assuming a circle with the indicated diameter, the area of closure would be approximately 1415 acres.

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FIGURE 12

NOVEMBER 29, 2010

Gross Hot Shale – Arthur Creek

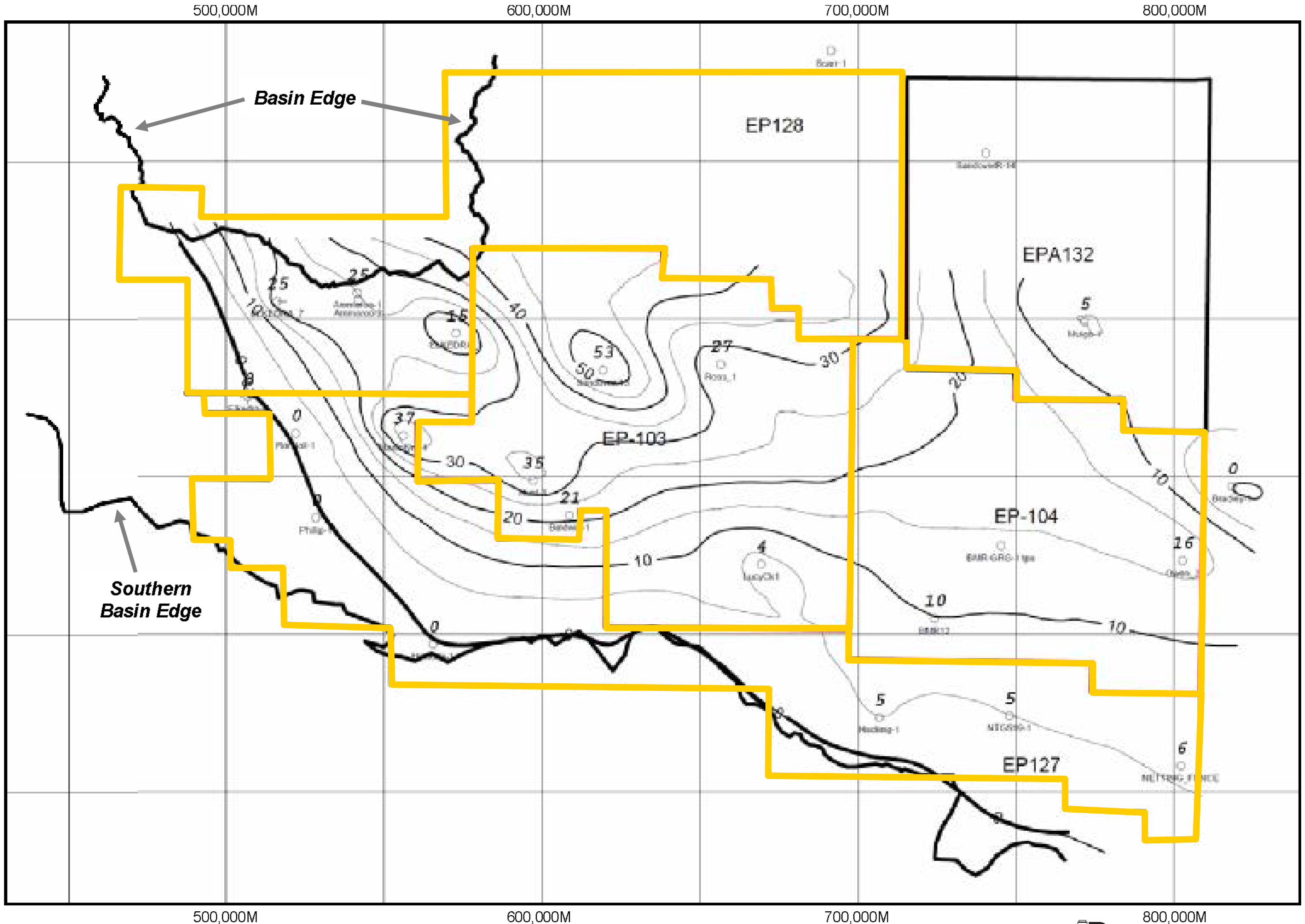

FIGURE 13 NOVEMBER 29, 2010

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

APPENDIX 2

TABLE 1

Ryder Scott's Petrophysical Evaluation of Conventional Reservoirs

Wells	Formation	Top Gross Pay	Base Gross Pay	Gross Thickness	Gross Pay (ø>4%)	Net Pay (Sw <60%)	NTG	Gross Pay Porosity %	Net Pay Porosity %	Gross Pay Sw %	Net Pay Sw %	Vsh (%)	Rw (Fmt)	Fmt (°C)	a	m	n	Comments
Hacking-1	Steamboat	745.4	752.8	7.40	5.30	0	0.716	8.43	–	73.63	–	9.4	1.467	51.3	1	2.178	2	quartzitic Calcarenite Intergranular porosity type
Owen-2	*Hagen Member*	583.1	643.6	60.52	21.63	1	0.357	9.1	10.79	68	52	1.97	1.583	41	1	2.3	2	*Excluded the fractured zones_ vuggy type porosity ,poor connectivity as evidenced by the petrology)*
		583.1	643.6	60.52	21.63	0	0.357	9.1	–	89	–	1.97	1.583	41	1	2.6	2	
	Steamboat	646.5	688.2	41.75	29.1	0	0.697	10.01	–	98	–	11.29	1.565	46.12	1	2.178	2	*Rw from pickett plot*
	Thorthonia	1067.0	1142.0	75.00	12.8	0	0.171	6.47	–	72	–	16.1	1.330	52.8	1	2.3	2	*very Poor connectivity as evidenced by core analysis and petrology*
Mulga-1	*Hagen Member*	523.5	597.0	73.50	23.9	3.4	0.325	9.2	14.60	67	50.5	2.95	1.636	38.3	1	2.3	2	*Excluded the fractured zones_old logs_only sonic log available*
		523.5	597.0	73.50	23.9	1.4	0.325	9.2	16.50	71.5	52.2	3.1	1.636	38.3	1	2.6	2	*Excluded the fractured zones_old logs*
Lucy Creek -1	*Hagen Member*	702.4	735.0	32.60	9	0	0.276	13.4	–	–	–	3.7						Produced 1300 bbls/h of fresh water from Hagen during the drilling
	Thortonia	1075.0	1104.2	29.20	3.7	0	0.127	10.9	–	69.3	–	7.5	0.455	60.3	1	2.3	2	*Old logs*
Sandover-13	*Hagen Member*	605.0	675.0	70.00	5	0	0.071	9.4	–	82	–	1.6	0.403	38.3	1	2.3	2	*Excluded zones 642 mand 648m fractured intervals (lost circulation)*
	Arthur Creek	716.1	853.0	136.90	23.4	23.4	0.171	8.72	8.72	–	47.7	8.88	0.374	41	1	2	2	*Soft Argilaceous dolomitic limestone*
	Arthur Creek	716.1	853.0	136.90	23.4	23.4	0.171	8.72	8.72	–	61.04	8.88	0.374	41	1	2.2	2	*Soft Argilaceous dolomitic limestone*
	Thortonia	941.4	1004.0	62.60	2.8	1.35	0.045	–	12.08	–	36.6	1.6	0.330	45	1	2.2	2	*Poor borehole conditions (enlargement)*
	Thortonia	941.4	1004.0	62.60	2.8	1	0.045	–	12.08	–	43.5	1.6	0.330	45	1	2.6	2	*Poor borehole conditions (enlargement)*
Baldwin-1	*Hagen Member*	421	471	50.00	11	3.2	0.220	7.2	8.20	61.9	51.2	0.5	0.443	42.7	1	2.3	2	*Moldic porosity, Poor interconnectivity*
	Hagen Member	421	471	50.00	11	0	0.220	7.2	–	72	–	0.5	0.443	42.7	1	2.6	2	
	Thortonia	890.0	960.0	70.00	0	–	–	–	–	–	–	–	–	–				*No reservoir interval present (Tight)*
MacIntyre-1	*Arthur Creek Shoal*	638.8	644.0	5.20	2.6	2.6	0.500	5.8	5.80	–	36	1.2	0.411	46.32	1	2	2	*High pore interconnectivity from core analysis & petrography*
Randall-1	*Hagen*	885.2	918.4	33.20	18.28	–	0.551	9.5	–	–	–	1.33	–	–	–	–	–	*Porosity from core analysis, DST tested 3oo bbl/d water*
Ross-1	*Thortonia*	934.8	975.0	40.20	14.3		0.356	6.6	–	–	–	5.5	–	–	–	–	–	*Log calibration questionable, DST recovered 23 BBl 5 ohm water*

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TABLE 2

Ryder Scott's Petrophysical Evaluation of Unconventional Hot Shale Reservoirs

Area	Wells	MD	Top Hot Shales	Base Hot shales	Gross Thick(m)	Net Pay (m)	NTG	Porosity %	Sw %	Rw (25°C) ohms	Comments
Toko Basin	Owen-2	191.6	1051	1067.1	16.1	2.8	0.174	11.40	37.00	2.2	Dolomitic siltstone
	Hacking-1	281.5	1197.5	1211.6	14.1	2	0.142	6.50	23.00	2.2	Silty Dolomite
	Coackroach	NA	NA	NA	10	NA					Government Publication
	Bradley	191.5	NP	NP	NP						Not Present
	Mulga-1	260.6	NDE	NDE	5						Extrapolation from correlation, Poor Logs
	Netting Fence	245.1	1954	1960	6						
	Todd-1	165.5	1314	1328	14						
Dulcie Basin	Amaroo-1&2	381			25						Estimated from Lithologue
	Randall-1	423.4			NP						Non deposition/erosion
	Phillip-2	426.9			NP						Non deposition/erosion
	Huckitta-1	545.5			NP						Non deposition/erosion
	Lucy Creek-1	302.4	1071.3	1075	3.7	PL					Poor Logs
	Baldwin-1	348	869	890	21	3	0.143	8.30	0.19	0.59	Carbonacious Mudstone, calculated
	Hunt-1	375.1	315	350	35	7	0.200	14.70	0.15	0.59	Dolomitic silstone, calculated
	MacIntyre-1	383.5	769	806	37	2.4	0.065	5.30	0.21	0.59	Silty Dolomits, calculated, PHI_Core
	Sandover-13	324.1	889	941.4	52.4	11	0.210				Silty Dolomits, Logs affected by caving
	Ross-1	326.5	907	934	27	2.2	0.081	0.04			Dolomitic Silstones, Logs needed, Recalibration
	NTGss99-1	NA	NA		6	NA					Government Publication
	Elkedra-3	NA	NA		15	NA					Government Publication
	Elkedra-6	NA	NA		NP	NA					Government Publication
	Elkedra-7	NA	NA		25	NA					Government Publication

NA	**Not available**
NDE	**Not deep enough**
NP	**Not Present**
PL	**Poor Logs**

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APPENDIX 3

SECTION 5

DEFINITIONS OF RESOURCES AND RESERVES

TABLE OF CONTENTS

5.1 Preface

5.1.1 Background

The Petroleum Society of CIM (Petroleum Society) Standing Committee on Reserves Definitions (Standing Committee) released revised *Definitions and Guidelines For Estimating and Classifying Oil and Gas Reserves* in January 2002. Later in 2002 these reserves definitions were adopted as the foundation for reserves estimation in the Canadian Oil and Gas Evaluation Handbook (COGEH).

The authors of COGEH and the Standing Committee each developed separate definitions of resources, incorporating terminology and concepts published in February 2000 by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), and the American Association of Petroleum Geologists (AAPG) (hereafter referred to as the 2000 SPE Resources Definitions). The COGEH version was published in COGEH in 2002, with the Standing Committee version being published in the second edition of the Petroleum Society's Monograph No. 1, *Determination of Oil and Gas Reserves*, in 2004.

The Standing Committee has now reviewed its definitions for both resources and reserves. Simultaneously, the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE) reviewed the 2000 SPE Resources Definitions and released revised definitions in April 2007 in its *Petroleum Resources Management System* (SPE-PRMS) document. This revision to COGEH has given due consideration to the SPE-PRMS and has resulted in notable changes to resources definitions, with only minor editorial changes to the previous reserves definitions and guidance.

There is now a broad alignment between the COGEH and SPE-PRMS definitions and guidelines, but some minor differences remain. Currently neither the sponsors of COGEH nor those of SPE-PRMS have fully endorsed all aspects of the other party's definitions, nor has such endorsement been requested.

5.1.2 Introduction

Petroleum is defined as a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid, or solid phase. The term "resources" encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Accordingly, total resources is equivalent to total Petroleum Initially-In-Place (PIIP). It is recommended that the term "total PIIP" be used rather than "total resources" in order to avoid any confusion that may result from the mixed historical usage of the term "resources" to mean the recoverable portion of PIIP or total PIIP.

The concept that a recovery or development *project* is required in order to recover resources from a petroleum accumulation is fundamental to the SPE-PRMS. One or more exploration, delineation, or development projects may be applied to an accumulation, and each project will provide additional technical data and/or recover an estimated portion of the PIIP. In the early stage of exploration or development, project definition will not be of the detail expected in later stages of maturity. For the purposes of government/regulatory resource management or for basin potential studies, projects will typically be defined with lesser precision. Regardless of the end use of estimates, a basic requirement for the assignment of recoverable resources in any category is that it must be possible to define a technically feasible recovery project.

Figure 5-1, taken from the SPE-PRMS, illustrates the main resources classification system. Additional operational subcategories may also be optionally used (see Section 5.3.4 a).

The vertical axis of Figure 5-1 represents the chance of commerciality. The key vertical categories relate to the quantities that are estimated to be remaining and recoverable; that is

- reserves, which are discovered and commercially recoverable;
- contingent resources, which are discovered and potentially recoverable but sub-commercial;
- prospective resources, which are undiscovered and potentially recoverable.

The range of uncertainty indicated on the horizontal axis of Figure 5-1 reflects that remaining recoverable quantities can only be estimated, not measured. Three uncertainty categories, or scenarios, are identified for estimates of recoverable resources — low estimate, best estimate, and high estimate (abbreviations for contingent resources are 1C, 2C, and 3C, respectively) — with the corresponding reserves categories of proved (1P), proved + probable (2P), and proved + probable + possible (3P).

Formal definitions for each element of Figure 5-1 are provided in Section 5.2.

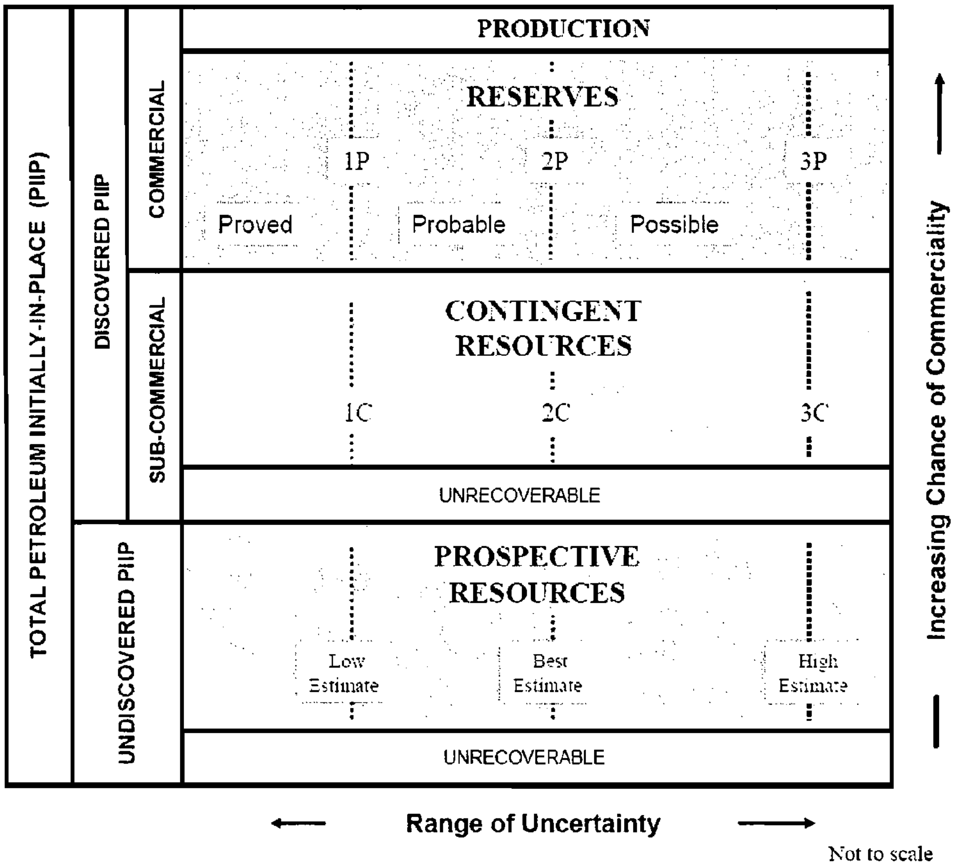

Figure 5-1 Resources classification framework (SPE-PRMS, Figure 1.1).

5.2 Definitions of Resources

The following definitions relate to the subdivisions in the resources classification framework of Figure 5-1 and use the primary nomenclature and concepts contained in the 2007 SPE-PRMS, with direct excerpts shown in italics.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

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

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

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status. Refer to the full definitions of reserves in Section 5.4.

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

Unrecoverable is that portion of Discovered or Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) *is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered.* The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

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Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity.

Unrecoverable: see above.

Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification. However, in some instances (e.g., basin potential studies) it may be desirable to refer to certain subsets of the total PIIP. For such purposes the term "resources" should include clarifying adjectives "remaining" and "recoverable," as appropriate. For example, the sum of reserves, contingent resources, and prospective resources may be referred to as "remaining recoverable resources." However, contingent and prospective resources estimates involve additional risks, specifically the risk of not achieving commerciality and exploration risk, respectively, not applicable to reserves estimates. Therefore, when resources categories are combined, it is important that each component of the summation also be provided, and it should be made clear whether and how the components in the summation were adjusted for risk.

5.3 Classification of Resources

For petroleum quantities associated with simple conventional reservoirs, the divisions between the resources categories defined in Section 5.2 may be quite clear, and in such instances the basic definitions alone may suffice for differentiation between categories. For example, the drilling and testing of a well in a simple structural accumulation may be sufficient to allow classification of the entire estimated recoverable quantity as contingent resources or reserves. However, as the industry trends toward the exploitation of more complex and costly petroleum sources, the divisions between resources categories are less distinct, and accumulations may have several categories of resources simultaneously. For example, in extensive "basin-center" low-permeability gas plays, the division between all categories of remaining recoverable quantities, i.e., reserves, contingent resources, and prospective resources, may be highly interpretive. Consequently, additional guidance is necessary to promote consistency in classifying resources. The following provides some clarification of the key criteria that delineate resources categories. Subsequent volumes of COGEH provide additional guidance.

5.3.1 Discovery Status

As shown in Figure 5-1, the total petroleum initially in place is first subdivided based on the discovery status of a petroleum accumulation. Discovered PIIP, production, reserves, and contingent resources are associated with known accumulations. Recognition as a known accumulation requires that the accumulation be penetrated by a well and have evidence of the existence of petroleum. COGEH Volume 2, Sections 5.3 and 5.4, provides additional clarification regarding drilling and testing requirements relating to recognition of known accumulations.

5.3.2 Commercial Status

Commercial status differentiates reserves from contingent resources. The following outlines the criteria that should be considered in determining commerciality:

- economic viability of the related development project;
- a reasonable expectation that there will be a market for the expected sales quantities of production required to justify development;
- evidence that the necessary production and transportation facilities are available or can be made available;
- evidence that legal, contractual, environmental, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated;
- a reasonable expectation that all required internal and external approvals will be forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approvals for expenditures, etc.;
- evidence to support a reasonable timetable for development. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a maximum time frame for classification of a project as commercial, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives.

COGEH Volume 2, Sections 5.5 to 5.8, provides addition details relating to the foregoing aspects of commerciality relating to classification as reserves versus contingent resources.

5.3.3 Commercial Risk

In order to assign recoverable resources of any category, a development plan consisting of one or more projects needs to be defined. In-place quantities for which a feasible project cannot be defined using established technology or technology under development are classified as unrecoverable. In this context "technology under development" refers to technology that has been developed and verified by testing as feasible for future commercial applications to the subject reservoir. In the early stage of exploration or development, project definition will not be of the detail expected in later stages of maturity. In most cases recovery efficiency will be largely based on analogous projects.

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources, and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality." The chance of commerciality varies in different categories of recoverable resources as follows:

- **Reserves:** To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.

- **Contingent Resources:** Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

- **Prospective Resources:** Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components — the chance of discovery and the chance of development.

5.3.4 Economic Status, Development, and Production Subcategories

a. Economic Status

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to subclassify contingent resources by economic status:

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

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

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is "undetermined" (i.e., "contingent resources – economic status undetermined").

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e., specified economic conditions, which are generally accepted as being reasonable (refer to COGEH Volume 2, Section 5.8).

b. Development and Production Status

Resources may be further subclassified based on development and production status. For reserves, the terms "developed" and "undeveloped" are used to express the status of development of associated recovery projects, and "producing" and "non-producing" indicate whether or not reserves are actually on production (see Section 5.4.2).

Similarly, project maturity subcategories can be identified for contingent and prospective resources; the SPE-PRMS (Section 2.1.3.1) provides examples of subcategories that could be identified. For example, the SPE-PRMS identifies the highest project maturity subcategory as "development pending," defined as "a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future."

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5.3.5 Uncertainty Categories

Estimates of resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project. Consequently, estimates of resources should generally be quoted as a range according to the level of confidence associated with the estimates. An understanding of statistical concepts and terminology is essential to understanding the confidence associated with resources definitions and categories. These concepts, which apply to all categories of resources, are outlined in Sections 5.5.1 to 5.5.3.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

- **Low Estimate:** This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.

- **Best Estimate:** This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.

- **High Estimate:** This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

5.4 Definitions of Reserves

The following reserves definitions and guidelines are designed to assist evaluators in making reserves estimates on a reasonably consistent basis, and assist users of evaluation reports in understanding what such reports contain and, if necessary, in judging whether evaluators have followed generally accepted standards.

The guidelines outline

- general criteria for classifying reserves,
- procedures and methods for estimating reserves,
- confidence levels of individual entity and aggregate reserves estimates,
- verification and testing of reserves estimates.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable, and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgement combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. These concepts are presented and discussed in greater detail within the guidelines in Section 5.5.

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

5.4.1 Reserves Categories

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

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;

- 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.

a. Proved Reserves

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.

b. Probable Reserves

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

c. Possible Reserves

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

Other criteria that must also be met for the classification of reserves are provided in Section 5.5.4.

5.4.2 Development and Production Status

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

a. Developed Reserves

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 (e.g., 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.

b. Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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 category (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.

5.4.3 Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Section 5.4.1 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 + probable reserves,
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3.

5.5 General Guidelines for Estimation of Reserves

The following is a summary of fundamental guidelines that should be followed by reserves evaluators. These general guidelines provide guidance that should aid in improving consistency in reserves reporting, but provide only a brief summary of the issues that may arise in applying the reserves definitions. It must be recognized that reserves definitions and associated guidelines cannot address all possible scenarios, nor can they remove the conditions of uncertainty that are inherent in all reserves estimates. It is the responsibility of the reserves evaluator to exercise sound professional judgement and apply these guidelines appropriately and objectively.

5.5.1 Uncertainty in Reserves Estimation

Reserves estimation has characteristics that are common to any measurement process that uses uncertain data. An understanding of statistical concepts and the associated terminology is essential to understanding the confidence associated with reserves definitions and categories.

Uncertainty in a reserves estimate arises from a combination of error and bias:

- Error is inherent in the data that are used to estimate reserves. Note that the term "error" refers to limitations in the input data, not to a mistake in interpretation or application of the data. The procedures and concepts dealing with error lie within the realm of statistics and are well established.

- Bias, which is a predisposition of the evaluator, has various sources that are not necessarily conscious or intentional.

In the absence of bias, different qualified evaluators using the same information at the same time should produce reserves estimates that will not be significantly different, particularly for the aggregate of a large number of estimates. The range within which these estimates should reasonably fall depends on the quantity and quality of the basic information and the extent of analysis of the data.

5.5.2 Deterministic and Probabilistic Methods

Reserves estimates may be prepared using either deterministic or probabilistic methods.

a. Deterministic Method

The deterministic approach, which is the one most commonly employed worldwide, involves the selection of a single value for each parameter in the reserves calculation. The discrete value for each parameter is selected based on the estimator's determination of the value that is most appropriate for the corresponding reserves category.

b. Probabilistic Method

Probabilistic analysis involves describing a range of possible values for each unknown parameter. This approach typically consists of employing computer software to perform repetitive calculations (e.g., Monte Carlo simulation) to generate the full range of possible outcomes and their associated probability of occurrence.

c. Comparison of Deterministic and Probabilistic Estimates

Deterministic and probabilistic methods are not distinct and separate. A deterministic estimate is a single value within a range of outcomes that could be derived by a probabilistic analysis. There should be no significant difference between reported reserves estimates prepared using deterministic and probabilistic methods.

d. Application of Guidelines to the Probabilistic Method

The following guidelines include criteria that provide specific limits to parameters for proved reserves estimates. For example, volumetric estimates are restricted by the lowest known hydrocarbon (LKH). Inclusion of such specific limits may conflict with standard probabilistic procedures, which require that input parameters honour the range of potential values.

Nonetheless, it is required that the guidelines be met regardless of analysis method. Accordingly, when probabilistic methods are used, constraints on input parameters may be required in certain instances. Alternatively, a deterministic check may be made in such instances to ensure that aggregate estimates prepared using probabilistic methods do not exceed those prepared using a deterministic approach including all appropriate constraints.

5.5.3 Aggregation of Reserves Estimates

Reported reserves typically comprise the aggregate of estimates prepared for a number of individual wells, reservoirs, and/or properties/fields.

When deterministic methods are used, reported reserves will be the simple arithmetic sum of all estimates within each reserves category. Evaluators and users of reserves information must understand the effect of summation on the confidence level of estimates. The confidence level associated with the arithmetic sum for a number of individual estimates may be different from that of each of the individual estimates. Arithmetic summation of independent high-probability estimates will result in a total with a higher confidence level; arithmetic summation of low-probability estimates will yield a total with a lower confidence level.

Because the definitions and guidelines require a conservative approach in the estimation of proved reserves, the minimum probability target for proved reported reserves will be satisfied with a deterministic approach as long as there are enough independent entity estimates in the aggregate. Where a very small number of entities dominate in the reported reserves, a specific effort to meet the probability criteria may be required in preparing deterministic estimates of proved reserves. Since proved + probable reserves prepared by deterministic methods will approximate mean values, the probability associated with the estimates will essentially be unaffected by aggregation.

When probabilistic techniques are used in reserves estimation, statistically based mathematical aggregation is performed within the probabilistic model. It is critical that such models appropriately include all dependencies between variables and components within the aggregation. Where dependencies and specific criteria contained in the guidelines have been treated appropriately, reserves for the various categories would be defined by the minimum probability requirements contained in Section 5.4.3, subject to the following considerations.

Reported reserves for a company will typically not be the aggregate results from a single probabilistic model, since reserves estimates are used for a variety of purposes, including planning, reserves reconciliation, accounting, securities disclosure, and asset transactions. These uses will generally necessitate tabulations of reserves estimates at lower aggregation levels than the total reported reserves. For these reasons and due to the lack of general acceptance of probabilistic aggregation up to the company level, reserves should not be aggregated probabilistically beyond the field (or property) level.

Statistical aggregation of a tabulation of values, which does not result in a straightforward arithmetic addition, is not accepted for most reporting purposes. Consequently, discrete estimates for each reserves category resulting from separate probabilistic analyses, which may, as appropriate, include aggregation up to the field or property level, should be summed arithmetically. As a result, reported reserves will meet the probability requirements in Section 5.4.3 regardless of dependencies between separate probabilistic analyses and may be summed with deterministic estimates within each reserves category.

It is recognized that the foregoing approach imposes an additional measure of conservatism when proved reserves are derived from a number of mathematically independent probabilistic analyses, because the sum of independent 90 percent confidence level estimates has an associated confidence level of greater than 90 percent. Nonetheless, this is considered to be an acceptable consequence given the need for a discrete accounting of component proved reserves estimates.

Conversely, this approach will cause the sum of proved + probable + possible reserves derived from a number of probabilistic analyses to fail to meet the 10 percent minimum confidence level requirement. Given the limited application for proved + probable + possible reported reserves, this is also considered to be an acceptable consequence.

5.5.4 General Requirements for Classification of Reserves

The following general conditions must be satisfied in the estimation and classification of reserves. More detailed guidance can be found in Chapter 5 of COGEH Volume 2.

a. Ownership Considerations

Assigning reserves to a company requires the company to own the subsurface mineral rights or have the contractual right to exploit and produce. This may be ascertained by reviewing land records and verified in financial records.

Internationally, in Production Sharing Contracts, the company will not usually own the mineral rights, but reserves may be assigned if the company has the right to extract the oil or gas. Further qualifications are

- the right to take volumes in kind,

- exposure to market and technical risk,
- the opportunity for reward through participation in producing activities.

Reserves would not be booked for companies participating in projects where their rights are limited to purchasing volumes or service agreements that do not contain aspects of technical and price risk and reward. Pure service contracts are an example of this type.

Company gross reserves are the working interest share of reserves prior to deduction of payments to others such as royalties (burdens).

Company royalty interest reserves are the net reserves received as a result of a royalty or carried interest.

Company interest reserves are the sum of company gross plus company royalty interest reserves. To avoid double accounting of reserves reported by a company, company royalty interest reserves must include only royalty volumes derived from non-related working interest owners.

Company net reserves are the working interest reserves after payment of burdens. Received royalty interests and carried interests are included in net reserves. Internationally, net reserves are after payments to governments. Depending on the PSC, they may be before or after payment of income tax.

b. Drilling Requirements

Proved, probable, or possible reserves may be assigned only to known accumulations that have been penetrated by a wellbore. Potential hydrocarbon accumulations that have not been penetrated by a wellbore may be assigned to prospective resources.

c. Testing Requirements

Confirmation of commercial productivity of an accumulation by production or a formation test is required for classification of reserves as proved. In the absence of production or formation testing, probable and/or possible reserves may be assigned to an accumulation on the basis of well logs and/or core analysis that indicates that the zone is hydrocarbon bearing and is analogous to other reservoirs in the immediate area that have demonstrated commercial productivity by actual production or formation testing.

d. Regulatory Considerations

In general, proved, probable, or possible reserves may be assigned only in instances where production or development of those reserves is not prohibited by governmental regulation. This provision could, for instance, preclude the assignment of reserves in designated environmentally sensitive areas. Reserves may be assigned in instances where regulatory restraints may be removed subject to satisfaction of minor conditions. In such cases the classification of reserves as proved, probable, or possible should be made with consideration given to the risk associated with project approval.

e. Infrastructure and Market Considerations

In order to assign reserves there should be an identifiable transportation infrastructure and a market to sell the oil or gas. The market requirement could vary from highly transparent spot markets such as exist in North America or the UK to long-term contracts in more remote areas of the world. If there is no existing market, the evaluator has to assess the level of confidence that one will be available within a reasonable time frame.

If there is no infrastructure in place, or the company has no ownership in nearby infrastructure, the evaluator has to assess the level of confidence that access to suitable infrastructure will be available within a reasonable time frame.

f. Timing of Production and Development

Non-producing reserves should be planned to be developed within a reasonable time frame. For projects requiring minor capital expenditures, two years is a recommended guideline unless the non-producing reserves are awaiting depletion of another producing zone or production levels are constrained by facility or market limitations. For larger capital expenditures, three years is a recommended guideline for assigning proved reserves and five years for assigning probable reserves. Exceptions to these guidelines are possible but should be clearly documented.

For producing reserves, extrapolating reserves over very long periods should take into account the uncertainties in forecasting volumes, fiscal terms, market factors, and infrastructure. It is recommended that reserves be limited to less than a 50-year forecast period unless there are clear reasons to extend beyond this.

g. Economic Requirements

Proved, probable, or possible reserves may be assigned only to those volumes that are economically recoverable. The fiscal conditions under which reserves estimates are prepared should generally be those considered to be a reasonable outlook on the future. Securities regulators or other agencies may require that constant or other prices and costs be used in the estimation of reserves and value. In such instances the estimated reserves quantities must be recoverable under those conditions and should also be recoverable under fiscal conditions considered to be a reasonable outlook on the future. In any event, the fiscal assumptions used in the preparation of reserves estimates must be disclosed.

Undeveloped recoverable volumes must have a sufficient return on investment to justify the associated capital expenditure in order to be classified as reserves as opposed to contingent resources.

5.5.5 Procedures for Estimation and Classification of Reserves

The process of reserves estimation falls into three broad categories: volumetric, material balance, and decline analysis. Selection of the most appropriate reserves estimation procedures depends on the information that is available. Generally, the range of uncertainty associated with an estimate decreases and confidence level increases as more information becomes available and when the estimate is supported by more than one estimation method. Regardless of the estimation method(s) employed, the resulting reserves estimate should meet the certainty criteria in Section 5.4.

a. Volumetric Methods

Volumetric methods involve the calculation of reservoir rock volume, the hydrocarbons in place in that rock volume, and the estimation of the portion of the hydrocarbons in place that ultimately will be recovered. For various reservoir types at varied stages of development and depletion, the key unknown in volumetric reserves determinations may be rock volume, effective porosity, fluid saturation, or recovery factor. Important considerations affecting a volumetric reserves estimate are outlined below:

- **Rock Volume:** Rock volume may simply be determined as the product of a single well drainage area and wellbore net pay or by more complex geological mapping. Estimates must take into account geological characteristics, reservoir fluid properties, and the drainage area that could be expected for the well or wells. Consideration must be given to any limitations indicated by geological and geophysical data or interpretations, as well as pressure depletion or boundary conditions exhibited by test data.

- **Elevation of Fluid Contacts:** In the absence of data that clearly define fluid contacts, the structural interval for volumetric calculations of proved reserves should be restricted by the lowest known structural elevation of occurrence of hydrocarbons (LKH) as defined by well logs, core analyses, or formation testing.

- **Effective Porosity, Fluid Saturation, and Other Reservoir Parameters:** These are determined from logs and core and well test data.

- **Recovery Factor:** Recovery factor is based on analysis of production behaviour from the subject reservoir, by analogy with other producing reservoirs, and/or by engineering analysis. In estimating recovery factors the evaluator must consider factors that influence recoveries, such as rock and fluid properties, PIIP, drilling density, future changes in operating conditions, depletion mechanisms, and economic factors.

b. Material Balance Methods

Material balance methods of reserves estimation involve the analysis of pressure behaviour as reservoir fluids are withdrawn, and they generally result in more reliable reserves estimates than volumetric estimates. Reserves may be based on material balance calculations when sufficient production and pressure data are available. Confident application of material balance methods requires knowledge of rock and fluid properties, aquifer characteristics, and accurate average reservoir pressures. In complex situations, such as those involving water influx, multi-phase behaviour, multi-layered or low-permeability reservoirs, material balance estimates alone may provide erroneous results.

Computer reservoir modelling can be considered a sophisticated form of material balance analysis. While modelling can be a reliable predictor of reservoir behaviour, the input rock properties, reservoir geometry, and fluid properties are critical. Evaluators must be aware of the limitations of predictive models when using these results for reserves estimation.

The portion of reserves estimated as proved, probable, or possible should reflect the quantity and quality of the available data and the confidence in the associated estimate.

c. Production Decline Methods

Production decline analysis methods of reserves estimation involve the analysis of production behaviour as reservoir fluids are withdrawn. Confident application of decline analysis methods requires a sufficient period of stable operating conditions after the wells in a reservoir have established drainage areas. In estimating reserves, evaluators must take into consideration factors affecting production decline behaviour, such as reservoir rock and fluid properties, transient versus stabilized flow, changes in operating conditions (both past and future), and depletion mechanism.

Reserves may be assigned based on decline analysis when sufficient production data are available. The decline relationship used in projecting production should be supported by all available data.

The portion of reserves estimated as proved, probable, or possible should reflect the confidence in the associated estimate.

d. Future Drilling and Planned Enhanced Recovery Projects

The foregoing reserves estimation methodologies are applicable to recoveries from existing wells and enhanced recovery projects that have been demonstrated to be economically and technically successful in the subject reservoir by actual performance or a successful pilot. The following criteria should be considered when estimating incremental reserves associated with development drilling or implementation of enhanced recovery projects. In all instances the probability of recovery of the associated reserves must meet the criteria for commerciality (Section 5.3.2), the general requirements (Section 5.5.4), and certainty criteria contained in Section 5.4.

If interpretations are such that no proved or probable reserves are assigned to a development project involving significant future capital expenditures, then the potentially recoverable quantities should be classified as contingent resources rather than stand-alone possible reserves.

i. Additional Reserves Related to Future Drilling

Additional reserves associated with future commercial drilling projects in known accumulations may be assigned where economics support, and regulations do not prohibit, the drilling of the location.

Aside from the criteria stipulated in Section 5.4, factors to be considered in classifying reserves estimates associated with future drilling as proved, probable, or possible include

- whether the proposed location directly offsets existing wells or acreage with proved or probable reserves assigned,
- the expected degree of geological continuity within the reservoir unit containing the reserves,
- the likelihood that the location will be drilled.

In addition, where infill wells will be drilled and placed on production, the evaluator must quantify well interference effects, that portion of recovery that represents accelerated production of developed reserves, and that portion that represents incremental recovery beyond those reserves recognized for the existing reservoir development.

ii. Reserves Related to Planned Enhanced Recovery Projects

Reserves that can be economically recovered through the future application of an established enhanced recovery method may be classified as follows.

Proved reserves may be assigned to planned enhanced recovery projects when the following criteria are met:

- Repeated commercial success of the enhanced recovery process has been demonstrated in reservoirs in the area with analogous rock and fluid properties.
- The project is highly likely to be carried out in the near future. This may be demonstrated by factors such as the commitment of project funding.
- Where required, either regulatory approvals have been obtained or no regulatory impediments are expected, as clearly demonstrated by the approval of analogous projects.

Probable reserves may be assigned when a planned enhanced recovery project does not meet the requirements for classification as proved; however, the following criteria are met:

- The project can be shown to be practically and technically reasonable.

- Commercial success of the enhanced recovery process has been demonstrated in reservoirs with analogous rock and fluid properties.

- It is reasonably certain that the project will be implemented.

Additional possible reserves may be assigned in a planned enhanced recovery project considering factors such as greater effective hydrocarbons in place or greater recovery efficiencies than those estimated in the proved + probable reserves scenario. As previously noted, stand-alone possible reserves should not be assigned to a potential future enhanced recovery project where conditions are such that no proved or probable reserves could be assigned. In such cases the potentially recoverable quantities would be classified as contingent resources, with a corresponding low, best, and high estimate.

5.5.6 Validation of Reserves Estimates

A practical method of validating that reserves estimates meet the definitions and guidelines is through periodic reserves reconciliation of both entity and aggregate estimates. The tests described below should be applied to the same entities or groups of entities over time, excluding revisions due to differing economic assumptions:

- Revisions to proved reserves estimates should generally be positive as new information becomes available.

- Revisions to proved + probable reserves estimates should generally be neutral as new information becomes available.

- Revisions to proved + probable + possible reserves estimates should generally be negative as new information becomes available.

These tests can be used to monitor whether procedures and practices employed are achieving results consistent with certainty criteria contained in Section 5.4. In the event that the above tests are not satisfied on a consistent basis, appropriate adjustments should be made to evaluation procedures and practices.