EMD Tight Gas Sands Committee

2018 EMD Tight Gas Sands Committee Annual Report

Dr. Dean Rokosh, Chair
Alberta Geological Survey/Alberta Energy Regulator, Alberta, Canada

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Contributors:

- **Ameed Ghori,** Geological Survey, Department of Mines and Petroleum, Western Australia, Australia
- **Nicole Villarreal,** Southwest Energy, Texas, U.S.A.

COMMITTEE ACTIVITIES

The Tight Gas Sands Committee is currently publishing with the Shale Committee.

EXECUTIVE SUMMARY

Tight gas is an unconventional hydrocarbon resource contained in low permeability (millidarcy to microdarcy range) and low porosity reservoirs. In the past only sandstone or siltstone was considered as 'tight', however increasingly carbonate reservoirs are also included as a tight reservoir. Tight gas reservoirs are historically a dry gas resource, but low gas prices have compelled companies toward resources containing liquids (oil or natural gas liquids).

Tight gas sands exploration and development, especially dry gas, is declining, particularly since the shale resource boom has accelerated. However, new reservoir classifications such as shale, hybrid and halo reservoirs attempt to draw distinctions between specific reservoirs; these reservoir definitions may overlap with the definition of a tight reservoir.

A continuum of play types exists, from fringe conventional oil and gas to unconventional tight gas or oil in sandstones and carbonates to unconventional shale gas and oil. The distinction between these various hydrocarbon commodities become less clear as the development of these plays continues to evolve.

This report summarizes tight gas characteristics and activity, where possible, in the United States, Australia, Canada, China, Argentina, Algeria, Oman, and Egypt. Eqypt was added this year.

STATUS OF U.S.A. TIGHT GAS ACTIVITIES

The U.S. Energy Information Administration (EIA) (2017) estimated in a 2017 report that as of January 1, 2015, 291.0 trillion cubic feet (Tcf) of Total Technically Recoverable Resources (TTRR) of dry, tight gas exists within the continental United States with 63.3 Tcf Proved Reserves and 227.8 Unproved Reserves). The total dry gas volume of 291 Tcf represents about 12% of the total TTRR of dry gas onshore and offshore (including Alaska).

The USGS (2014) has evaluated tight gas and oil resources in the following basins: Appalachian Basin; Arkoma Basin; Big Horn Basin; Denver Basin; Piedmont, Blue Ridge Thrust Belt, Atlantic Coastal Plain, and New England; Eastern Oregon and Washington; North-Central Montana; Powder River Basin; San Juan Basin; Southern Alaska Basin; Southwestern Wyoming Basin; Uinta-Piceance Basin; Wind River Basin. This information is available on their website.

In some cases, partial or whole revisions to the basin assessment have been made and are also available; e.g., Appalachian Basin Energy Resources: A New Look at an Old Basin (Rupert and Ryder, 2014).

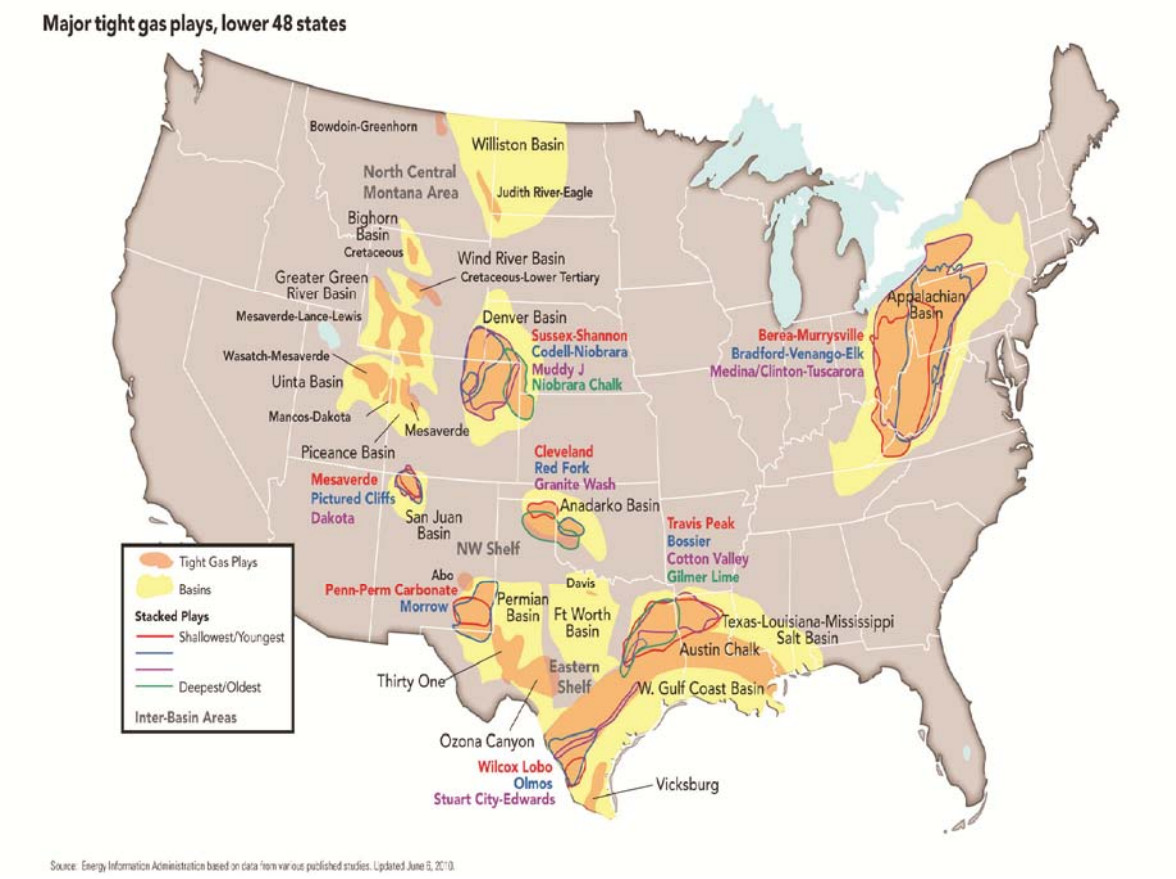

Figure 1. Major tight plays in the lower 48 states, U.S.A. in 2010. A newer digital map published by the USGS (2014) is available (https://pubs.usgs.gov/dds/dds-069/dds-069-hh/downloads/DDS69-HH_plate1.pdf). The details of the new digital map are not reproducible here at this scale

The Energy Information Agency (EIA) of the U.S.A. no longer carries a definition in its online glossary for tight gas; hence production is not itemized in the latest annual reports (2016 forward). According to the EIA, "With the full deregulation of wellhead natural gas prices and the repeal of the associated Federal Energy Regulatory Commission (FERC) regulations, tight natural gas no longer had a specifically defined meaning, but generically still refers to natural gas produced from low-permeability sandstone and carbonate reservoirs."

According to the EIA, notable tight natural gas formations include, but are not limited to

- Clinton, Medina, and Tuscarora formations in Appalachia
- Berea sandstone in Michigan
- Bossier, Cotton Valley, Olmos, Vicksburg, and Wilcox Lobo along the Gulf Coast
- Granite Wash and Atoka formations in the Midcontinent
- Canyon formation in the Permian Basin
- Mesaverde and Niobrara formations in multiple Rocky Mountain basins

(https://www.eia.gov/energyexplained/index.cfm?page=natural_gas_where)

In the following section we will be updating tight gas drilling and production in selected areas of the U.S.A.

Texas: Gas Production and Tight Gas Activities

Throughout the United States, pressures due to challenging economic circumstances have elicited a paradigm shift in natural gas and oil production. Exploration and development companies hoping to stay competitive have been forced off their originally-set paths and in new, more innovative directions. A highly popular option for these companies is focusing their operations within Texas, a prolific energy producer for the country (Figure 2). As can be seen in Figure 2, natural gas is the primary source of energy produced within the state of Texas. Twenty-three percent of the United States' natural gas reserves lie within the borders of Texas, allowing the state to lead the nation in natural gas production (Table 1). In addition, 163 natural gas production plants within the state average a total of 19.7 billion ft^3 of natural gas produced per day, giving Texas the largest processing capacity in the country (Buchele et al., 2018).

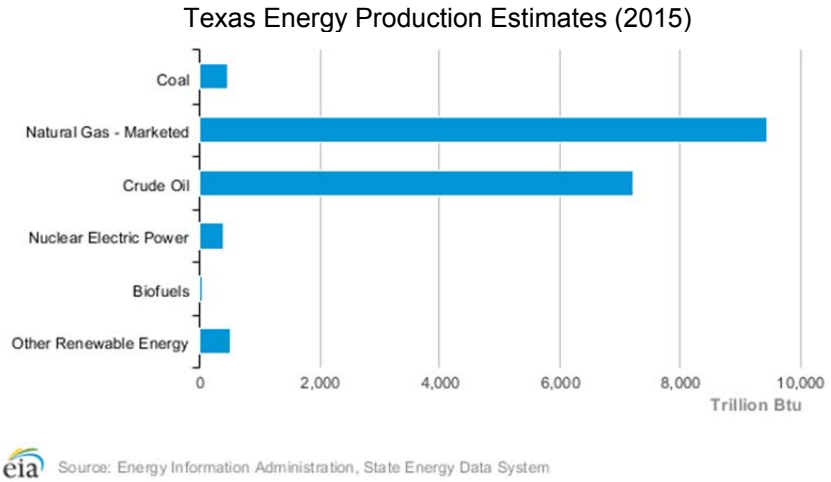

Figure 2. Energy production estimates for the state of Texas in 2015. From Energy Information Administration, 2018b.

Table 1. Natural gas well production in Texas from 2012-2018. Historical production data may be queried from the Railroad Commission of Texas website (www.rrc.state.tx.us). From Christian et al., 2018b.

GAS WELL GAS (natural gas production from gas wells, measured in MCF)							
MONTH	2012	2013	2014	2015	2016	2017	2018
JANUARY	601,109,043	571,297,463	552,630,097	559,363,016	506,255,600	443,554,741	* 373,721,093
FEBRUARY	556,055,811	519,937,601	498,157,306	506,126,393	474,327,167	406,776,031	
MARCH	590,624,076	577,036,536	559,794,180	558,534,274	501,908,133	444,989,323	
APRIL	575,807,269	557,996,288	550,260,715	537,818,150	482,826,690	433,205,486	
MAY	591,931,740	579,734,915	572,780,225	547,112,930	497,215,231	448,152,505	
JUNE	569,213,616	561,778,694	552,301,838	525,171,735	476,971,654	433,016,338	
JULY	590,782,665	578,776,038	566,223,561	541,545,858	484,000,905	443,014,248	
AUGUST	592,339,572	576,883,417	566,406,622	536,464,499	480,362,808	428,434,198	
SEPTEMBER	573,146,516	553,690,098	541,442,836	516,003,452	455,841,107	414,211,803	
OCTOBER	586,702,444	574,803,124	564,120,179	528,136,985	467,030,635	433,400,114	
NOVEMBER	561,882,249	545,781,109	547,685,557	509,203,768	445,154,314	416,044,098	
DECEMBER	572,270,009	551,546,134	574,035,109	514,860,201	447,462,234	415,019,345	
ANNUAL TOTAL	6,961,865,010	6,749,261,417	6,645,838,225	6,380,341,261	5,719,356,478	5,159,818,230	373,721,093

*Preliminary crude oil and gas well gas monthly production total - Significant changes to the preliminary production figures will occur in decreasing amounts for approximately six to eight months due to the filing of corrected and late reports by industry. Commission staff anticipates that the production totals following the period are substantially complete, although continued minor changes occur thereafter. There is no point beyond which an operator may not file corrected production reports.

There are numerous tight gas fields throughout the entirety of Texas. Since 1970, the United States government has defined tight gas reservoirs as those where permeability is less than 0.1-millidarcies (mD) (Holditch, 2006). This definition is largely legal and has been used for tax credit determinations for producers extracting gas from such reservoirs. A more general definition for tight gas reservoirs are those that require hydraulic fracturing and stimulation treatments in order to produce economic volumes (Holditch, 2006). The most recent complete listing of Approved Tight Formation Area Certifications for the Railroad Commission of Texas, published in January 2018, was over 700 pages long (Christian, 2018a). These fields can be found across the state at several thousand to over 10,000 feet below the surface. The Travis Peak formation of East Texas is an example of a tight gas sand field within the state.

Travis Peak Formation

Overview

The USGS lists the Travis Peak Formation as an Early (Lower) Cretaceous conglomerate, sandstone, and limestone found stretching along the northern Gulf of Mexico coastal plain (USGS, 2018b). It stretches from eastern Texas across southern Arkansas, Louisiana, Mississippi, and Alabama into the panhandle of Florida (Bartberger et al, 2003). In states other than Texas, the Travis Peak Formation is referred to as the Hosston Formation. This article will focus primarily on the formation's production within the state of Texas (Figure 3).

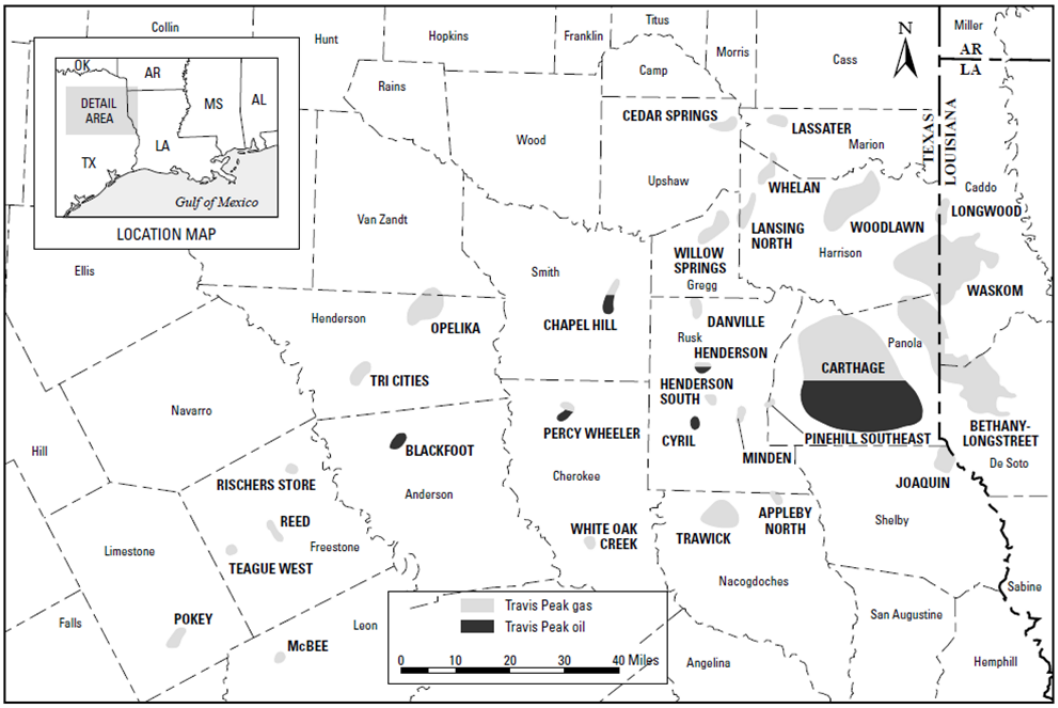

Figure 3. Map of the major hydrocarbon-producing fields from the Travis Peak Formation sandstones in northeastern Texas. Although the Travis Peak Formation stretches throughout and has producing fields within northern Louisiana and southern Arkansas, this article focuses on production within Texas. From Bartberger et al., 2003.

Producing Zones and Permeability

The Travis Peak Formation is composed primarily of fine-grained quartzarenites and subarkoses with interlayering shales deposited in a fluvial-deltaic environment (Dutton, 1987 and Fracasso, 1986). It is primarily from these sandstone layers that production occurs, and, due to oxidation of the organic matter within the shale layers, is not self-sourcing (Bartberger et al., 2003). Further evidence for the formation's inability to self-source is a total organic carbon content, primarily vitrinite, of less than 0.5% (Dutton et al., 1987). The underlying Bossier Shale and Smackover Formations (both Jurassic), are the most likely source rocks (Figure 4, Bartberger et al., 2003).

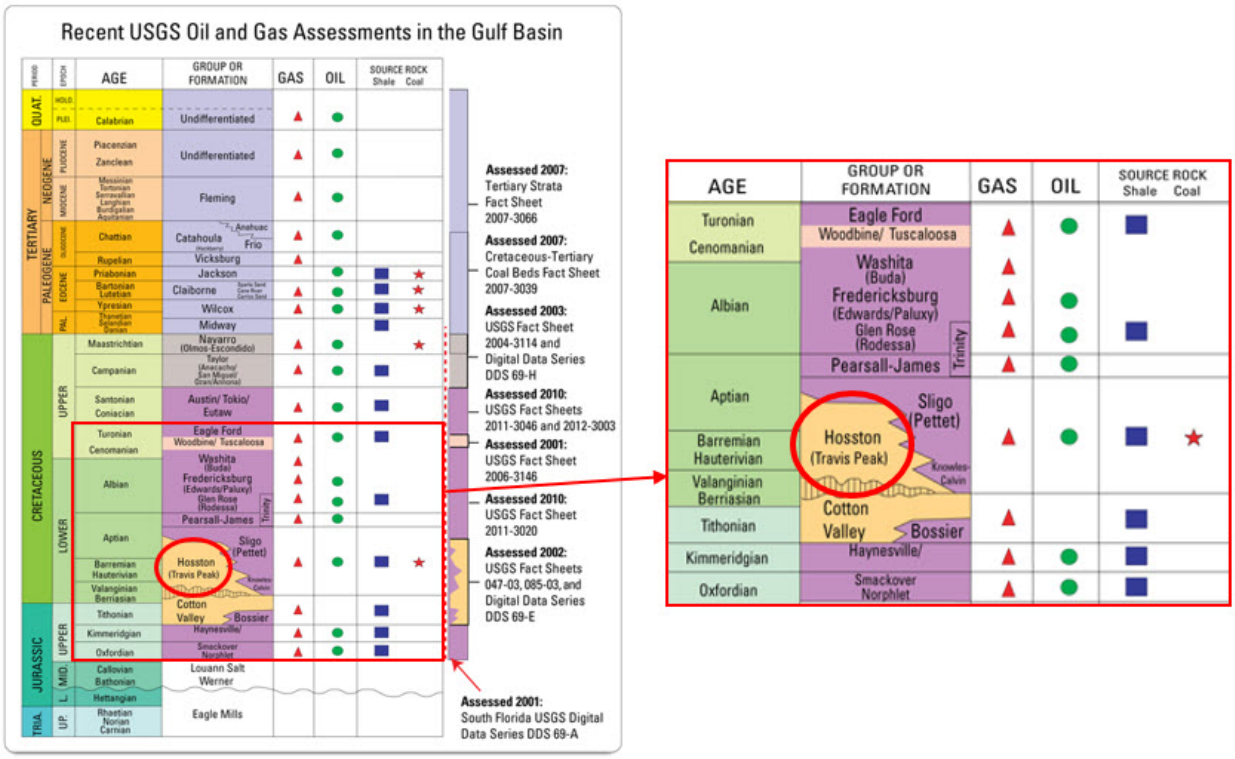

Figure 4. USGS stratigraphic column depicting the Gulf Basin. The Travis Peak (Hosston) Formation is encircled in red. The deeper Bossier Shale and Smackover Formations are both likely source rocks. Adapted from USGS, 2018a.

The majority of hydrocarbon production in the Travis Peak Formation occurs at depths from 6,000-10,000'. Less than 8,000' in depth, matrix permeability of the formation is above the legal definition of a tight rock of 0.1 mD. However, once 8,000' in depth is reached, compaction, a diagenetic overprint of quartz cementation, and minimal pressure solution lowers the permeability of these sandstones past the 0.1 mD cutoff (Dutton, 1987). In additional to various stimulation techniques, pervasive natural fracturing assists with production (Bartberger et al., 2003).

An IHS search into the Travis Peak formation reveals 9,425 well records dating back to 1919, with truly constant production commencing in 1940 (Figure 5). Of these records, 885 have the specific designation of "tight gas" for the play type. These well counts indicate completions for the "tight gas" designated wells started in the beginning of 2000 (IHS, 2018). The data indicate a definitive drilling peak within the formation from 2007-2008 with a fairly steep decline beginning in 2009, correlative with a drop in Henry Hub Natural Gas Spot Price (Energy Information Administration, 2018a and IHS, 2018).

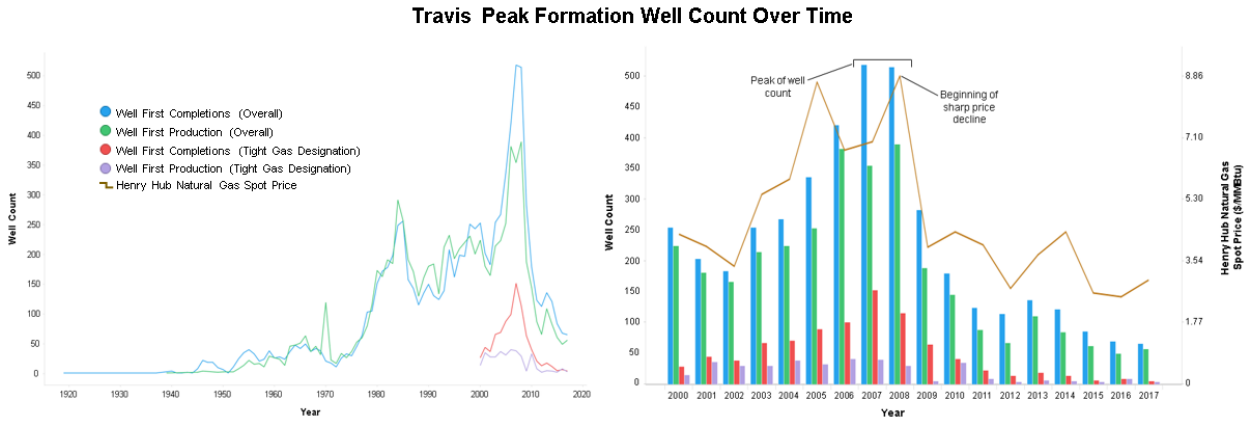

Figure 5. The graph on the left indicates gas well first completions and first production dates from an IHS search for the Travis Peak Formation within Texas. The graph on the right is the same information limited to beginning in the year 2000 corresponding to the first "tight gas" designation with the addition of Henry Hub Natural Gas Spot Prices. The numbers for "overall" and "tight gas" designations are not additive; "tight gas" well counts are also included in the "overall" well counts. All data is cut at the end of 2017, as that is the last complete year of information at the time of records acquisition. Annual price for 2017 was calculated via aggregation of monthly data. Data from Energy Information Administration, 2018a and includes content supplied by IHS Markit; Copyright © IHS Markit, 2018. All rights reserved.

As the Travis Peak Formation was part of a comprehensive study within the Gas Research Institute (GRI) Tight Gas Sands Program, which studied gas-producing sandstones with low permeability, there is a dearth of information on the formation. Numerous other studies have been conducted on the Travis Peak Formation, likely due to the prolific nature, wide expanse, and proximity of the formation to various academies with a petroleum focus. As such, further information on this producing zone is widely available.

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A few selected summaries of historical tight gas formations, not on the above EIA list are as follows:

Dew-Mimms Creek Field, East Texas Basin, U.S.A.

The Dew-Mimms Creek field produces from a series of stacked sand-shale successions. Each succession contains 75–100 feet (23–30 m) of net sand with average porosity ranging from 6–10%, absolute permeability from 1 microdarcy (μD) to 1 millidarcy (mD), and water saturation ranging from 5%–50%. The play seeks to exploit an overpressured cell by drilling for gas close to the overpressure ceiling which is at depths of 12,400–13,200 feet (3,780–4,023 m). The Dew-Mimms Creek field, as of 2013, is being developed on 80–160 acre (32.4–64.8 ha) well spacing. Wells are fracture stimulated with small to large slickwater fracs by pumping 100,000 to 350,000 pounds (lbs) (45,360 to 158,757 kilograms (kg)) of proppant. Initial well rates range from 2 to 5 million cubic feet per day (MMcfd) (56.6–141.5 thousand cubic meters per day (E3m^3/d)) and declines are hyperbolic with flows stabilizing after 2–3 years at 500–900 thousand cubic feet per day (Mcfd) (14.2–25.5 E3m^3/d). Estimated ultimate recovery (EUR) per well ranges from 1 to 4 billion cubic feet (Bcf)(28.3–113.2 million cubic meters (E6m^3)). Geological factors controlling well success include the ability to locate main channel sand trends where sands are thicker and of better quality, and to established sustained economic production rates from inferior reservoirs through improved completion practices.

Jonah Field, Green River Basin, Wyoming, U.S.A.

The Jonah field is fault-bounded and contains a stacked succession of 20–50 fluvial channel sands from the Upper Cretaceous Lance Pool (Lance and Mesa Verde Formations) in an interval that is 2,800–3,600 feet (853–1,097 m) thick, and occurs at depths of 8,000–19,000 feet (2,440–5,780 m). The field has a productive area of 21,000 acres and is estimated to contain 10.5 trillion cubic feet (297 billion cubic meters) of natural gas (https://www.wyohistory.org/encyclopedia/jonah-field-and-pinedale-anticline-natural-gas-success-story). Sandstone bodies occur as individual 10–25 foot (3.0–7.6 m) thick channels stacked into channel sequences up to 200 feet (61 m) thick. Porosity ranges from 5%–14%, with permeability of 1–30 μD and water saturation from 30–60%. The pressure gradient is 0.55–0.60 psi/foot (37.9–41.3 millibars/0.3 m). Cumulative production reported to the end of 2017 for 2,234 wells are 4,955 billion cubic feet of gas (Bcf) and 47.1 million barrels of oil (MMBbl).

According to the Wyoming Geological Survey, nearly 400 wells were completed in the Greater Green River Basin, mostly in the large Jonah and Pinedale natural gas fields. In March, a horizontal well in the Pinedale field produced 54.5 MMcfe/d (million cubic feet equivalent per day) during a 24-hour initial production period. The average initial production from new horizontal wells on the flank of the Pinedale Anticline is about 7.8 MMcfe/d. This means the new horizontal wells have the potential to produce up to seven times more gas per day than a normal Pinedale directional well (http://wogcc.wyo.gov/news-announcements/wsgsupdatesonlineoilandgasmapofwyoming).

Mamm Creek Field, Piceance Basin, Colorado, U.S.A.

In the Mamm Creek field the main producing interval is the 2,000 feet (610 m) thick, over-pressured Williams Fork Formation which consists of lenticular fluvial to marine sands at depths of 4,500–8,500 feet (1,372–2,591 m). The maturation of coals and organic marine shales (Mancos Fm.) essentially charged the thick sedimentary column. Packages of "stacked sands" can be correlated over areas of 30–70 acres (12–28 ha). Results from 200 well tests showed permeability ranging from 1–100 μD with half the tests indicating the presence of open fractures.

Drilling has slowed considerably in the Piceance Basin due to depressed gas prices. Cumulative production reported to the end of 2013) for 3780 wells are 1222 Bcf gas, 10.5 MMBbl oil, 69.9 MMBbl water and a Water-Gas-Ration (WGR) of 57.2 bbls/MMcf.

According to the Grand Junction Daily Sentinel (September 2018), the pace of drilling in the western Piceance Basin was on track prior to the November election to be similar to 2017, or about 307 wells. Up to September 2, 2019 196 wells were drilled in Garfield County and 67 wells in Mesa county.

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STATUS OF INTERNATIONAL TIGHT GAS ACTIVITIES

According to McGlade et al. (2012), tight gas exploration is occurring in many other areas of the world than the U.S.A., but estimates have been difficult to gather, in some cases because tight gas is included in conventional gas estimates. Nonetheless, McGlade et al. (2012) "presents an overview of the current estimates" of 1914 Tcf (54.5 trillion cubic meters)) of technically recoverable tight gas from 14 regions or countries in the world.

Below we summarize some of the more notable tight gas and oil plays from a variety of references.

STATUS OF ALGERIA TIGHT GAS ACTIVITY

The In Salah Gas Projects of Algeria in the Ahnet-Timimoun Basins contain some seven gas fields, three of which in the north have been on production since 2003 and 4 dry new fields in the south brought on production in 2016. The northern fields include the Teguentour, Krechba and Reg Fields, of which Hirst et al (2001) describes the Teguentour as primarily a tight gas reservoir.

In the Tegentour Field, conventional sandstones are interbedded with volumetrically dominant tight reservoirs (<1mD). The tight gas intervals are from Devonian and Carboniferous rocks with quartz cementation being relatively pervasive and the main cause of lower porosity and permeability, "often in the microdarcy range" (Hirst et al. 2001). Sandstone porosity in the tight zones is up to about 9%. Initial gas production of the three northern fields was at about 317 - 353 Bcf/yr (9 – 10 Bm^3/yr) (OGJ Online July 7,

2004; http://www.ogj.com/articles/2004/07/algerias-in-salah-gas-fields-now-producing.html). According to the field operator, the development of the southern fields will help maintain production at about 9 billion cubic metres per annum.

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STATUS OF ARGENTINA TIGHT GAS ACTIVITY

Argentina is the largest gas producer in South America at 1.35 Tcf (38.3 billion cubic metres) and 619,000 bopd during 2016 (https://www.theoilandgasyear.com/market/argentina). Gas production was dominated by wells in the Neuquen province followed by the Chubut, Santa Cruz, Santa and Mendoza provinces.

The 4000 m-thick fill of the Neuquen basin straddles the Argentina and Chile border and contains one of the most complete Jurassic-Early Cretaceous marine fossil records, with spectacular finds of both marine and continental vertebrates. The basin is the most important hydrocarbon-producing province in southern South America, with 1.7 Billion Barrels (BBbls) (280.4 x 10^6 m^3) of oil produced and an estimated 1.01 BBbls)(161.9 x 10^6 m^3) of oil remaining.

Although oil production has often received most of the attention, Wood Mackenzie Ltd. suggest tight gas production is driven by lower cost and pricing incentives, USD $7.50MM/BTU in 2018 (U.S. dollars) for wells drilled in the Neuquen basin dropping to $5/MMBTU in 2021. This incentive was expected to draw in about USD $5 Billion in 2017 increasing to USD $15 Billion in 2018. The success in the Neuquen basin resulted in the program being extended to the Austral Basin in November 2017.

Tight production in the Neuquen Basin "almost tripled" over a 2 year period to 565 MMcf/d during the first quarter of 2017; gas production in the basin was about 2% higher to the end of 2017 relative to 2016 (http://www.kallanishenergy.com/2018/02/06/a-look-into-argentinas-evolving-oil-and-gas-industry/). Six formations in the Wood Mackenzie Ltd. report (Mulichinco, Los Molles, Punta Rosada, Basamento and Precuyo; http://www.drillingcontractor.org/shale-tight-gas-production-argentinas-neuquen-basin-rise-venezuela-suffers-dramatic-production-declines-40150) with top quartile wells have flow rates five times higher than bottom quartile wells. For example, of the six wells studied the 90-day initial production rate from the median well was about 2 MMcf/d. Hydraulically fractured horizontal wells (slickwater?) in the Mulichinco Formation had the highest Estimated Ultimate Recovery (EUR) of 5 Bcf. Flow rates in other strata such as the Lajas Formation were more variable while production from the Punta Rosada is expected to be best achieved using vertical wells. Variability in flow rates suggested that a 'statistical approach to field development is likely.

About 300 unconventional wells are expected to be drilled in 2018 for either shale or tight gas(http://interfaxenergy.com/gasdaily/article/29171/argentina-ready-to-switch-from-tight-gas-to-shale), and during 2018 shale gas drilling is projected to surpass tight gas drilling.

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STATUS OF AUSTRALIAN TIGHT PETROLEUM ACTIVITIES

This present report (2019) updates the previous report that summarizes the search for emerging tight gas and oil resources (petroleum) in onshore basins of Australia. During 2018, tight-petroleum search activities remain low due to fracking restrictions and low oil and gas prices. The moratorium on fracking for unconventional petroleum in parts of Western Australia, Northern Territory, South Australia, New South Wales and total ban in Victoria impacted the petroleum exploration activities in Australia (Figure 1), which was recently lifted in some parts of Australia.

Figure 1. Australian map showing the fracking restrictions on unconventional petroleum exploration and production.

The status of tight-petroleum exploration in Australia is quite different compared to the United States. In the United States, tight-petroleum drilling and production is increasing with time, whereas in Australia drilling are production are in early stages relative to the date of the first tight-petroleum resource assessment (Kuuskraa et al., 2013), which rated Australia amongst the top-rated countries (Figure 2). At this stage, tight petroleum resources are considered as prospective resources, because there is little experience to show how productive these reservoirs will be in Australia. Thus time, experience and sharing of geoscience and operational knowledge are needed to understand and define and produce these resources. Production from conventional reservoirs is in decline, not only in Australia but globally, while energy demand is increasing.

Production from tight-petroleum resources, as exemplified by the United States production, is a prime example of one method of how meet global petroleum demand.

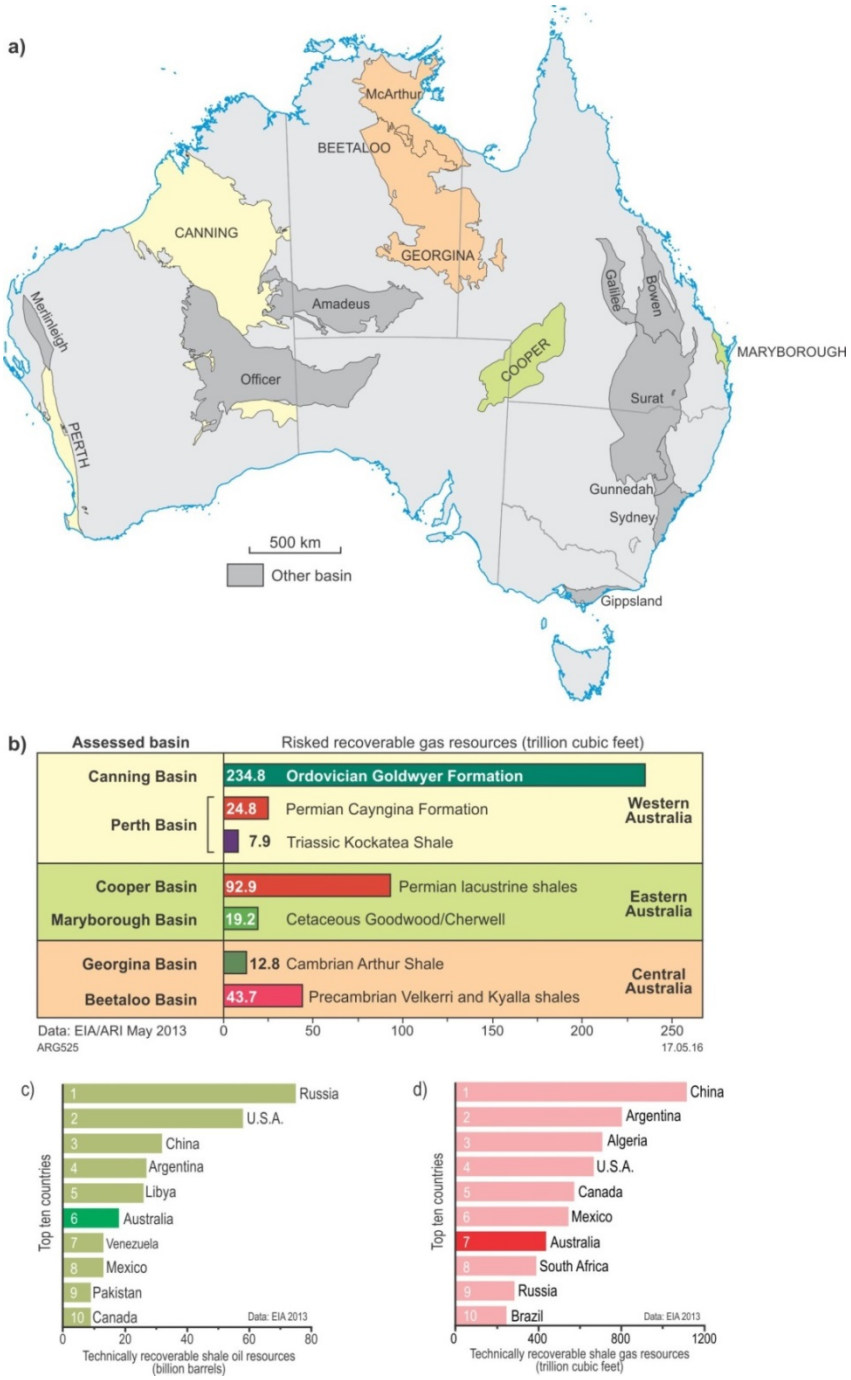

Figure 2. Potential tight gas and oil resources in Australian basins: a) geographic distribution; b) estimated resources; c) Australian rating for oil resources and; d) for gas resources.

In Australia, the search for conventional petroleum resources started in the 1950s, which extended to tight sand and shale reservoirs in 2010. Exploration of these reservoirs is still in the initial stages. These petroleum reservoirs exhibit a continuum from a conventional reservoir pore-throat size greater than 2 μm, to between 2–0.03 μm in tight-gas sandstone, and 0.1–0.005 μm in shale (Nelson, 2009). Of these, shale reservoirs are the tightest, but richest in petroleum resources.

An estimate of tight petroleum resources of Australia includes technically recoverable 437 Tcf of gas and 17.5 billion barrels of oil (Kuuskraa et al., 2013), or up to 1000 Tcf of gas according to Cook et al. (2013). Geoscience Australia has also assessed the potential for unconventional gas and oil in the onshore Gippsland, Otway, Perth, Cooper and Canning basins, based on publicly available data (Table 1). The assessments indicate large volumes of oil-in-place, but with a high degree of uncertainty.

Table 1. Tight petroleum resources in selected basins of Australia

Basin resource	**Estimated oil-in-place (Bbbl)**				**Potentially recoverable oil resources (5% of P50; Bbbl)**
	P90	P50	P10	Mean	
Gippsland Basin					
Shale resources	10.1	22.4	46.0	25.8	1.1
Perth Basin					
Shale resources	26.1	60.6	127.2	70.3	3.0
Cooper Basin					
Shale resources	5.8	8.9	12.9	9.2	0.4
Tight resources	253.9	490.2	956.3	559.9	24.5
Total					24.9
Canning Basin					
Shale resources	513.2	860.2	1416.5	926.5	43.0
Otway Basin					
Shale resources	15.4	20.7	27.2	21.1	1.0
Tight resources	5.9	8.8	13.5	9.3	0.4
Total					1.5
Bbbl = billion barrels; P50 = 50 per cent confidence interval Sources: Lewis et al. (2018a, b, c); Wang et al. (2018a, b)					

Geographically, these resources are within the organic-rich shale and tight-sand reservoirs of Queensland, South Australia, Northern Territory, and Western Australia (Figure 2).

Stratigraphically, these resources are within: the Precambrian Velkerri and Kyalla shale of the Beetaloo Basin; the Cambrian Arthur Shale of the Georgina Basin; the Ordovician Goldwyer Formation of the Canning Basin; the Permian Roseneath-Epsilon-Murteree (REM) formations of the Cooper Basin, the Permian Carynginia Formation of the Perth Basin; the Triassic Kockatea Shale of the Perth Basin; and the Cretaceous Goodwood/Cherwell Mudstone of the Marlborough Basin (Figure 3).

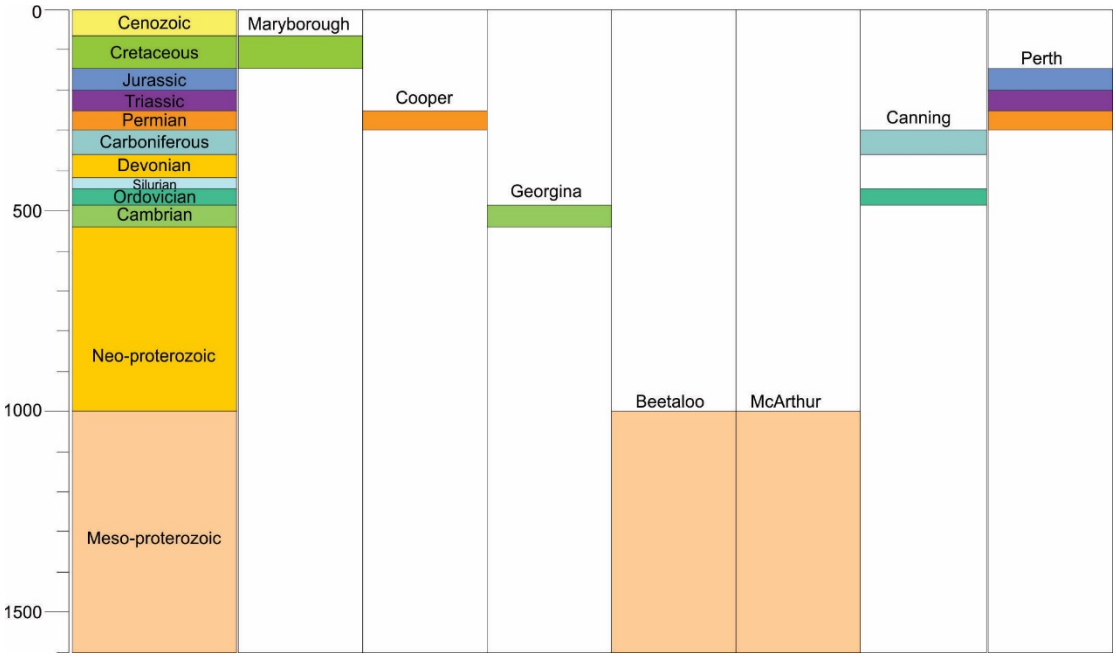

Figure 3. The Stratigraphic position of the Australian Basin with tight oil and gas potential.

Geological assessment and regulations to develop these resources are underway over the last few years and will continue for several years. At this stage, mostly vertical wells are drilled with limited fracturing intervals, as opposed to thousands of horizontal wells with many fracturing intervals within the United States. Challenges to developing these resources include a very small Australian market, a lack of infrastructure, remote locations, and social license to operate.

Fracking has been used in Australia but current regulations are uneven and inconsistent in each state and territory. Last year, Victoria became the first state to permanently ban fracking in on onshore basin. There are certain restrictions on fracking in Tasmania and New South Wales. The South Australian government is planning a 10-year ban on fracking in much of the state's south-east. Queensland, more broadly, allows the practice.

Recently, the moratorium on fracking for unconventional petroleum in parts of the Northern Territory and Western Australia has been lifted in April and November 2018, respectively. However, in Western Australia, fracking would be allowed on existing petroleum titles and industry need to demonstrate that it has the support of landowners who, for the first time, will be able to say yes or no to any fracking production on their land. The Northern Territory enforces strict new laws and regulations on industry.

However, studies related to tight petroleum assessment continue in Australia, and over $2.3 million dollars (Australian) has been spent on Australian tight petroleum research (Table 2).

Table 2. Summarizes historic Australian tight petroleum research investment

BASIN	YEAR	AMOUNT $	COMPANIES
Perth	2011	$200 MM	Alco, AWE, Norwest, Warrego
Canning	2010	$150 MM	Conco/ New Standard
	2011	$120 MM	Buru/ Mitsubishi
	2012	$55 /14 MM	Hess/ Fortescue
Georgina	2011	$55 MM	Hess
	2012	$120 MM	Statoil
Amadeus	2012	$150 MM	Santos/ Central
Cooper	2011	$130/ >18 MM	BG-Drillsearch/ Santos, Beach, Strike, Senex, Chevron
Galilee	2011	$50 MM	CNOOC/ Exoma

The moratorium has stopped the drilling programs of many companies including Buru Energy and AWE, as well as Japanese giant Mitsubishi, from exploring for onshore gas in Western Australia, which contains some of the nation's biggest untapped deposits.

The Northern Territory government has recently lifted its moratorium on fracking, and drilling and assessment programs can begin within the McArthur, Beetaloo, and Georgina basins, which contain some of the world's oldest untapped deposits.

Eastern Australia

The Cooper and Maryborough basins are prospective for tight gas and oil resources. Of these, the Cooper Basins has the highest exploration activity in Australia, while no exploration activity is presently occurring in the Maryborough Basin.

Permian Cooper Basin

The Cooper Basin is a late Carboniferous–Middle Triassic intracratonic basin in north-eastern South Australia and south-western Queensland (Figure 4 and 5). The Patchawarra, Nappamerri, and Tenappera are major troughs, which are separated by structural ridges. Exploration for tight gas and oil are within the Toolachee, Nappamerri, Daralingie, and Patchawarra tight sand and shale reservoirs. Of these, the Roseneath, Epsilon, and Murteree formations, referred to as REM, are the target for potential: basin-centered-gas, shale-gas, and deep-coal-gas (Figure 4).

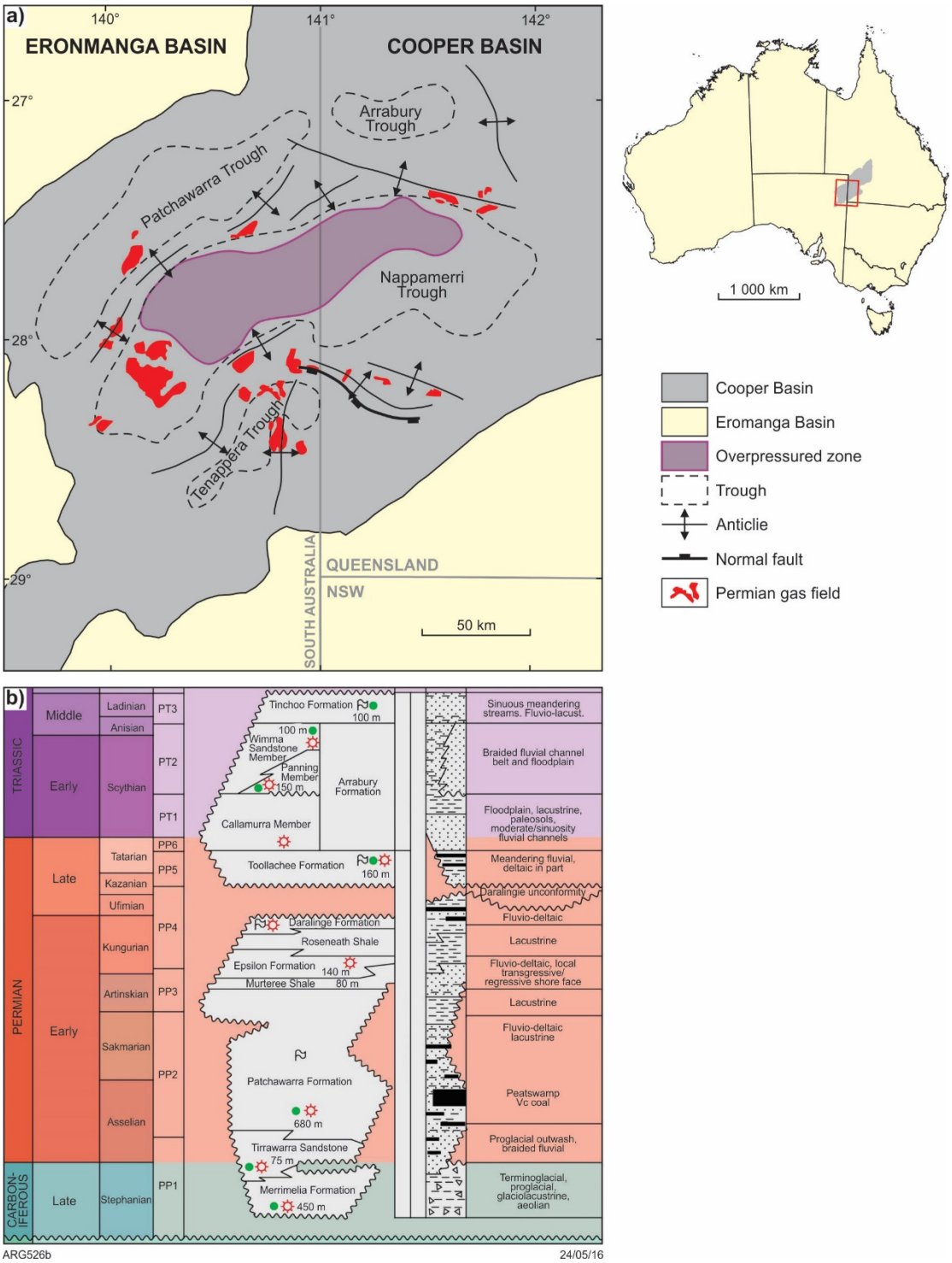

Figure 4. Cooper Basin of Eastern Australia: a) map showing major troughs and, b) showing stratigraphy.

The Cooper Basin is a major onshore gas producing province of Australia (Figure 4) with a well developed infrastructure for gas supply to the Eastern States. The basin has the highest exploration activity in Australia to assess potential tight gas and oil resources. Estimated technically recoverable resources are up to 93 Tcf gas and 1.6 billion barrel of oil (Kuuskraa et al., 2013). Since 2011, over 29 wells were drilled by Beach Energy (merged with Drillsearch Energy), Icon Energy, Senex Energy, and Santos.

Santos's Moomba 191 was the first Australian well producing tight shale-gas from the Permian REM formations in September 2012. The initial flow rate was 3 MMscfd (million square cubic feet per day), which reduces 2 MMscfd in 2013. Over 5 additional wells have been drilled to assess Moomba-shale gas potential. Santos has drilled many wells to assess basin-centered-gas (Gaschnitz 1, Van der Waals 1, Langmuir1, Gaschnitz 3D), as well as for deep-coal-gas (Moomba-77, Roswell 1).

Encounter 1 and Holdfast 1 were the first shale wells of Beach Energy (Figures 5 and 6). Both wells had a peak gas flow rates of about 2.1 MMscfd with a single stage simulation in the uppermost Patchawarra Formation. Moonta 1 was the first well to stimulate the full Patchawarra section and achieved the highest flow rate, recorded flows at a maximum controlled rate of 2.6 million standard cubic feet per day. Beach Energy has drilled over 14 wells with several fracturing intervals (Figures 4 and 5).

The Cooper Basin is highly prospective for basin-centered gas plays within the REM formations; these formations are over 1 km thick, gas saturated, and over-pressurized.

Vintage Crop 1 was the first unconventional gas well drilled by Senex Energy in 2011, which is about 65 kilometers south-east of Moomba.

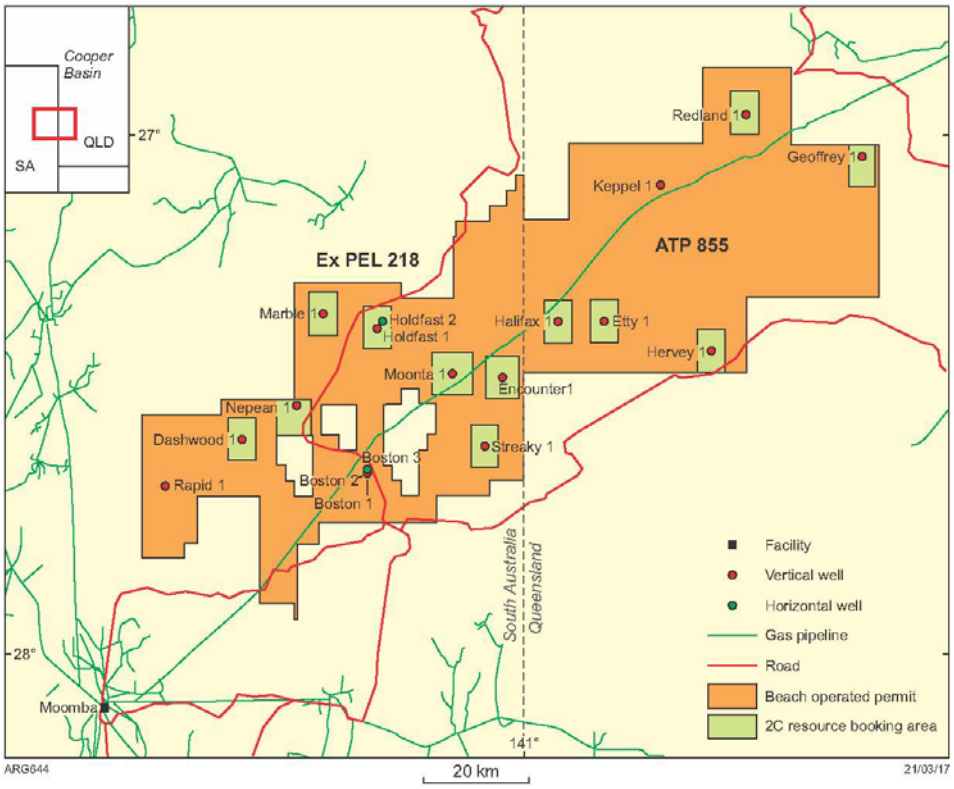

Figure 5. Map showing Beach Energy well locations in the Cooper Basin (source Beach website).

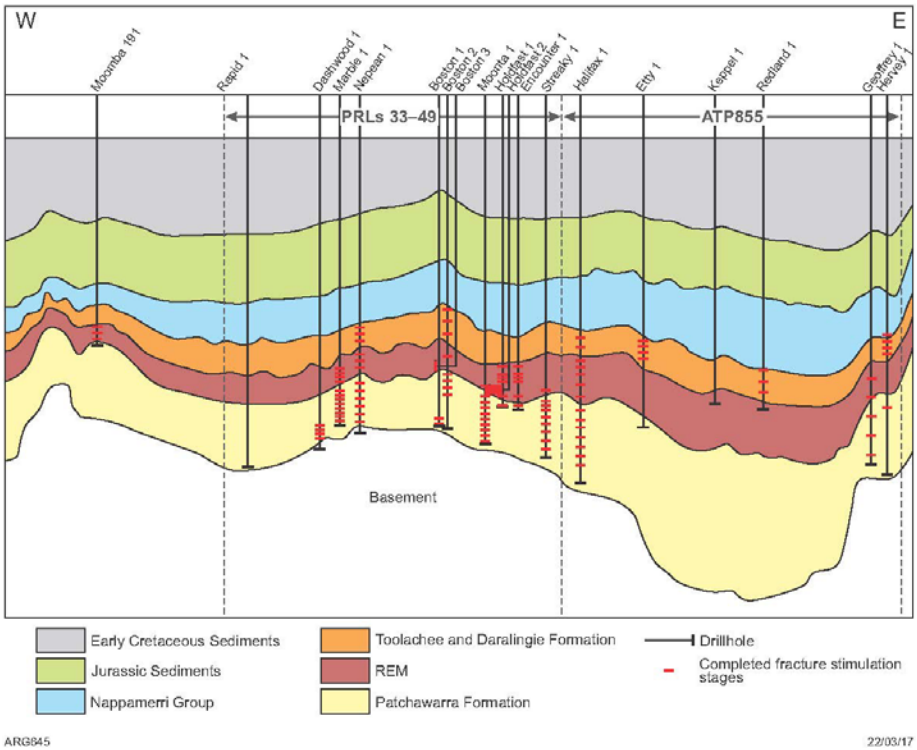

Figure 6. West-east cross section is showing fracture stimulation intervals in Beach wells (source Beach website).

Beach Energy has drilled several wells in South Australia, while Beach and Icon have drilled in the Queensland part of the Cooper Basin, a total of 18 wells. Of these, 16 wells were fracture stimulated, and all stimulated wells flowed gas to the surface. They estimated 495 million barrels of oil-equivalent contingent resources (2C) for the Daralingie Formation and Patchawarra Sand play. They have confirmed the play concept and drilling continues for further appraisal.

Central Australia

Petroleum exploration activity in the onshore basins of the Northern Territory in 2017 was largely limited to the Amadeus Basin, with no substantial exploration in the greater McArthur Basin (including the Beetaloo Sub-basin) pending the outcome of the Scientific Inquiry into Hydraulic Fracturing.

Proterozoic McArthur Basin

The most organic-rich source rocks in the Palaeo-Mesoproterozoic McArthur Basin are reported from the lacustrine Barney Creek Formation (c.1640 Ma) in the McArthur Group and the marine Velkerri Formation (c. 1440 Ma) in the Roper Group. Source rocks with comparable thickness and potential to Phanerozoic source rocks are present in these sequences with TOC of up to 7% containing type I and II kerogens, with thermal maturities ranging from overmature to marginal mature (Crick et al. 1988). Weeping oil and gas occurred from cores; blowouts occurred in several shallow wells drilled for lead-zinc exploration in the mid-1970s.

The McArthur, Beetaloo, and Georgina basins (Figure 7) are prospective for tight gas and oil resources. In Central Australia, the Beetaloo Basin is the most prospective onshore basin for unconventional gas. The McArthur and Beetaloo basins are, probably, the oldest basins of the world to be explored for tight petroleum resources.

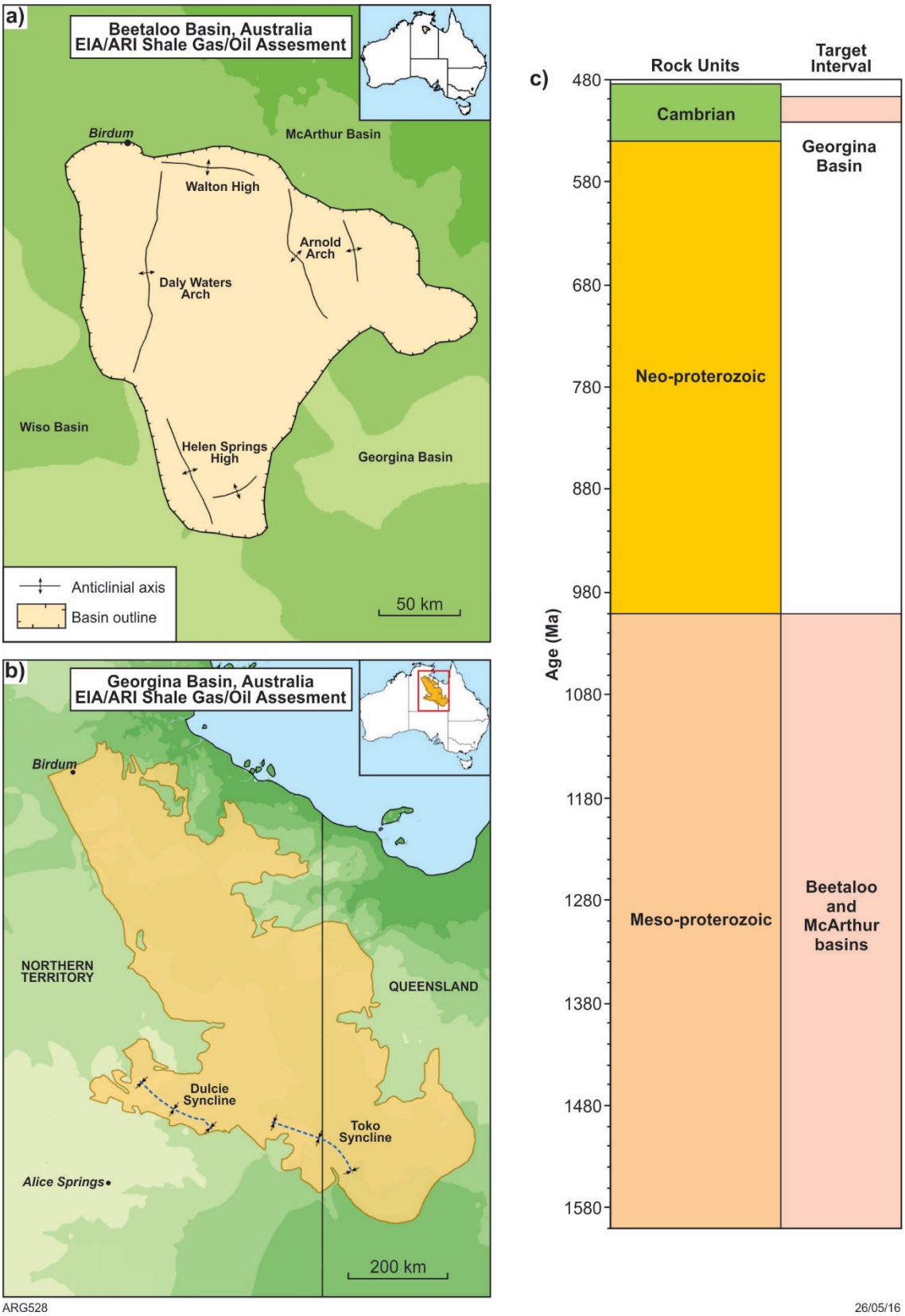

Figure 7. Central Australian basins with tight-petroleum potential: a) Beetaloo Basin; b) Georgina Basin; and c) stratigraphic position of these basins.

Proterozoic Beetaloo Basin

The Beetaloo Basin is the most prospective onshore basin for unconventional gas (Figure 8). Origin Energy's new Amungee NW-1H well flowed at 1.1 MMcf/d over almost two months from the Velkerri B Shale (Figure 8). Origin Energy has delineated a giant shale play around the successfully Amungee NW-1H well (Figure 9) with a gross contingent resource of 6.6 trillion cubic feet (2C), enough to support an LNG train at Darwin or APLNG in the east.

Amungee NW-1H well was extensively tested just before the fraccing moratorium by Northern Territory government. The results of all wells drilled to date, and the regional seismic data assessed the potential for the Velkerri Formation to extend over some 10,000 km². The B shale appears to have similarities with the Marcellus and Barnett shales in the US, and so far significant amounts of data from the Amungee NW-1H, Beetaloo W-1, Kalala S-1, McManus-1, Altree-2 and Walton-2 wells, and Santos' deep Tanumbirini-1 well support that conclusion. The Velkerri B shale is interpreted to be the most continuous of the three individual targets within the Velkerri Formation shale gas play. Amungee NW-1H well was drilled some 600 m into the B Shale and with 11 fracs flowed at rates that promise commerciality. The Schlumberger frac was one of the largest ever conducted in Australia.

Further exploration and appraisal activity will be required to understand the shale play and help convert contingent resources to reserves. Additional data required are 3D seismic to determine inter-well shale properties, micro-seismic, and tracer surveys to understand the fracture networks better, and bottom-hole pressure surveys to help define well spacing. The Northern Territory government has tasked an independent panel look again into the risks and controls needed if fraccing is to be allowed.

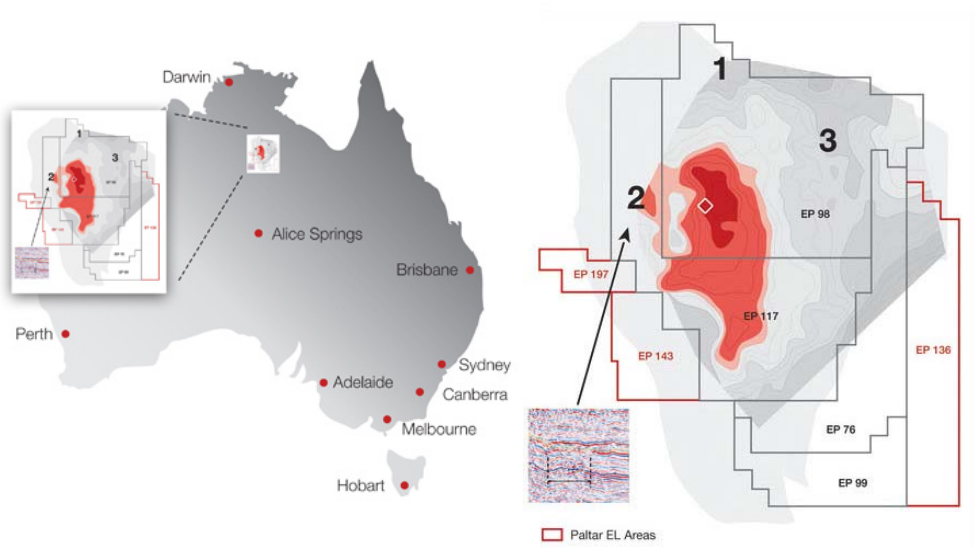

Figure 8. Map showing Origin Energy shale gas exploration area within the Beetaloo Basin, where a potential gas-in-place of 61 Tcf is estimated for an area covering 1968 km within EP 76, EP 98, and EP 117.

Figure 9. Amungee NW-1H well (Origin Energy) that successfully flowed at 1.1 million cubic feet per day over almost two months from the Velkerri B Shale.

Two different oil types have been observed: a heavily biodegraded oil containing associated galena, sphalerite and barite, which was probably generated and migrated during the phase of lead-zinc mineralization; and a 'golden honey color', very volatile oil generated during the later tectonic events (Wilkins 2007). In the 1979 mineral borehole, GRNT-79-9 gas was ignited and sustained a 6 m high yellow smoky gas flare for approximately 6 months producing an estimated 0.5 Bcf gas at 6 MMscfd. Gas analyses showed the presence of C1-C7 hydrocarbons. Besides, oil bleeds are common in cores indicating the presence of shale oil.

Recently, Glyde 1 and ST1, Cow Lagoon 1, and Kilgour 1 wells have been drilled by Armour Energy Limited to test shales of the Barney Creek Formation, which is a proven gas-prone target in the South McArthur Basin.

Cow Lagoon 1 drilled to a total depth of 2755 ft. (840 m) in June 2012 to test the Barney Creek Formation, with gas shows reported on mud logs.

Kilgour North 1 was drilled to a total depth of 3749 ft. (1142.8 m) during July 2012 to test the Barney Creek Formation and reported minor gas shows on mud logs. In this well, repeated water inflows were intersected at 1148 ft. (350 m), 2461 ft. (750 m), and 3747 ft. (1142 m), thus drilling was suspended, and the drilling rig was relocated to the Glyde drill site. The Kilgour North #1 well was logged and suspended.

Glyde 1 and the ST1 sub-horizontal well was drilled to a true vertical depth of 840 m during 2012. The key objective was to provide repeated intersections of the existing natural fracturing in the Barney Creek Formation and assess how this can be utilized to potentially provide commercial production. The Barney Creek Formation encompasses approximately 123,000 acres (500 km^2). Flow testing has confirmed a flow of 3.33 MMscfd at 125 psi pressure after 10 minutes on a 64/64 inch choke, after intersecting and testing the estimated down hole location of the historic 1979 GR-9 mineral exploration borehole in the Barney Creek Formation. The Glyde #1 lateral well has continued to encounter gas bearing formations from 2126 ft. (648 m) to 2657 ft. (810 m) measured depth in the lateral well at a vertical depth of circa 1640 ft. (500 m). The gas constituents defined from gas chromatography remain at approximately 77% Methane (C_1), 11%

Ethane (C_2), 11% Propane (C_3), 0.8% i+n-Butanes (C_4), 0.2% i+n- Pentanes (C_5) with negligible Carbon Dioxide. The test results substantiate a highly prospective resource area in the Glyde Sub Basin of approximately 123,000 acres (500 km^2).

Western Australia

The stratigraphy and vast geographic extent of the onshore Western Australia basins (Figure 10 and 11) suggest high potential for tight shale and sand petroleum resources. Basins rated from high to low potential include the Paleozoic Canning Basin, the Paleozoic–Mesozoic Perth Basin, the Paleozoic Southern Carnarvon Basin, and the Neoproterozoic Officer Basin, respectfully. Currently, search for tight shale and sand petroleum resources are within the Canning and Perth basins (Figure 12).

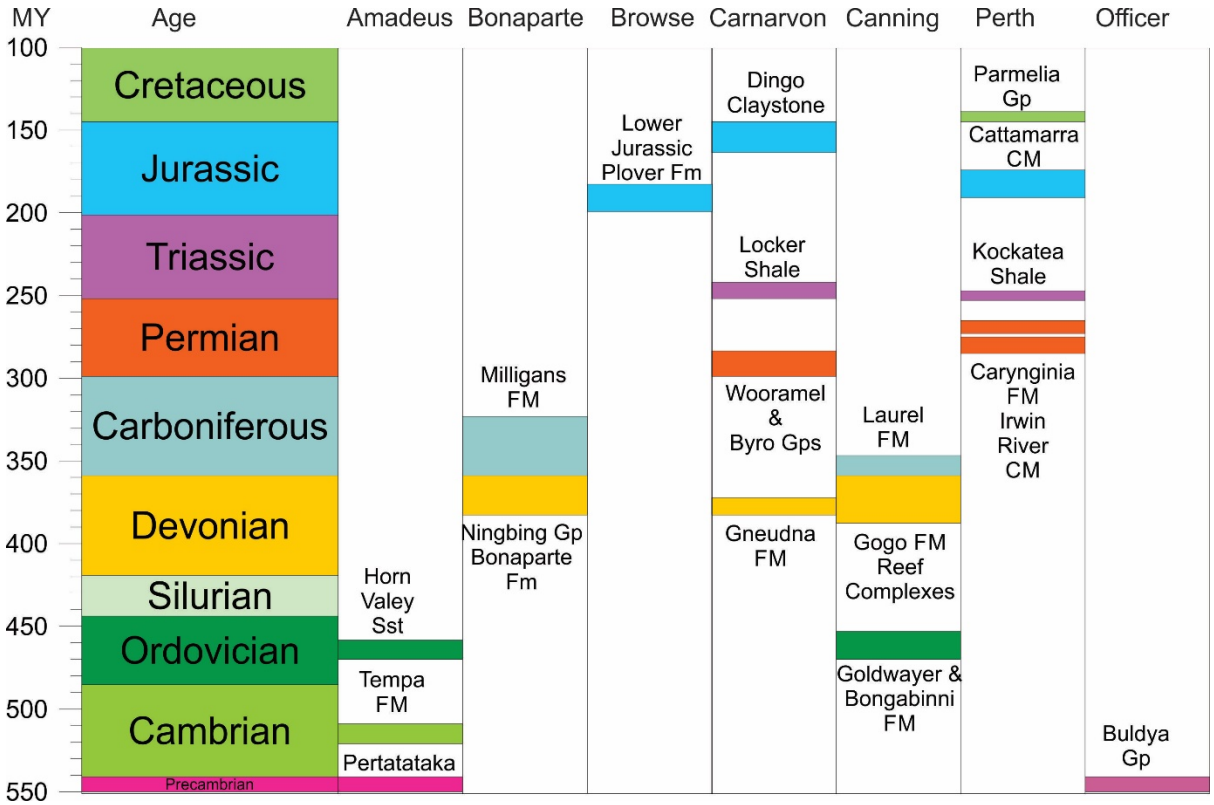

Figure 10. Stratigraphic distribution of source rocks, which may have prospective tight-petroleum resources in Western Australia.

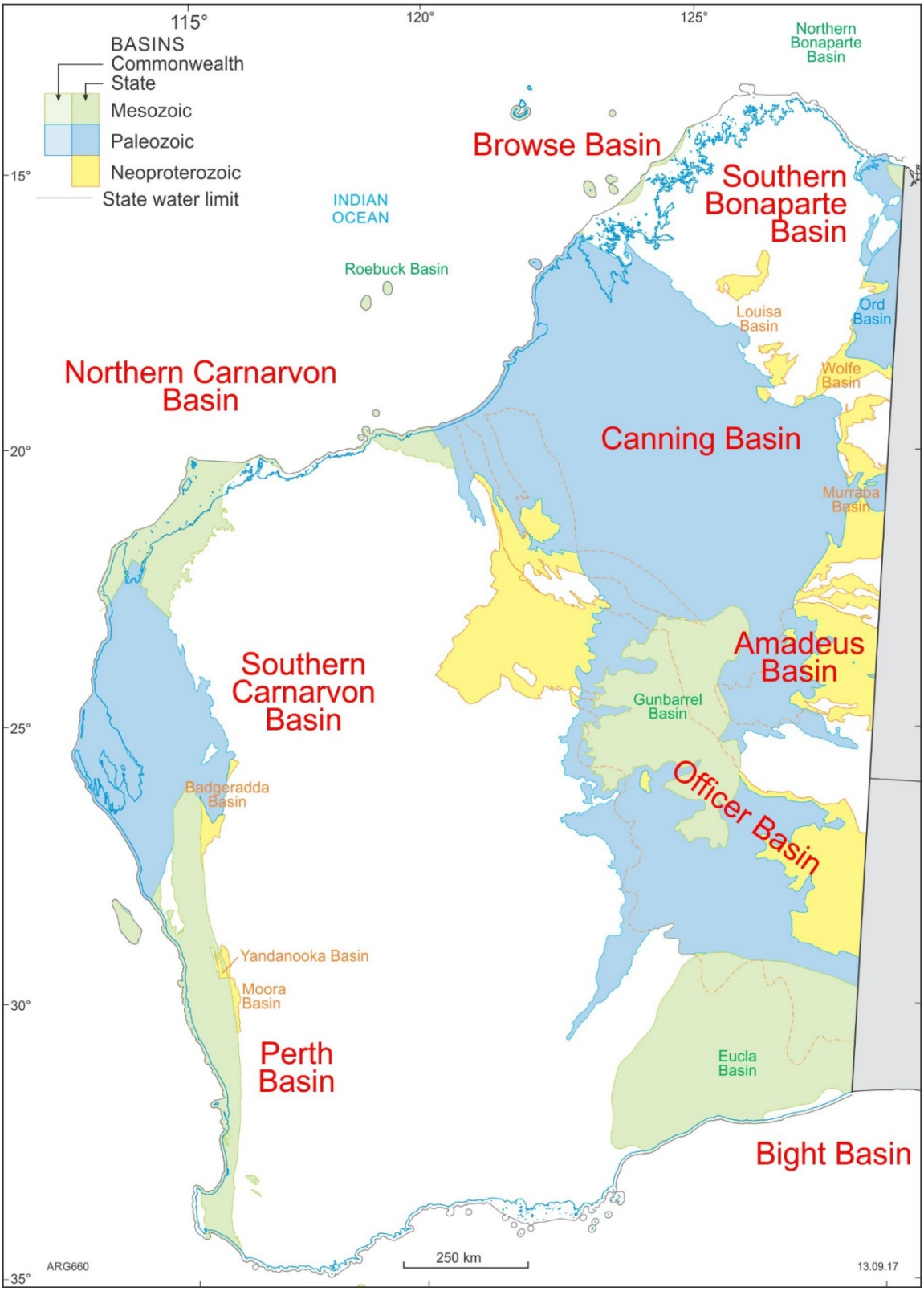

Figure 11. Geographic distribution of Western Australian basins, which may have prospective tight-petroleum resource in Western Australia.

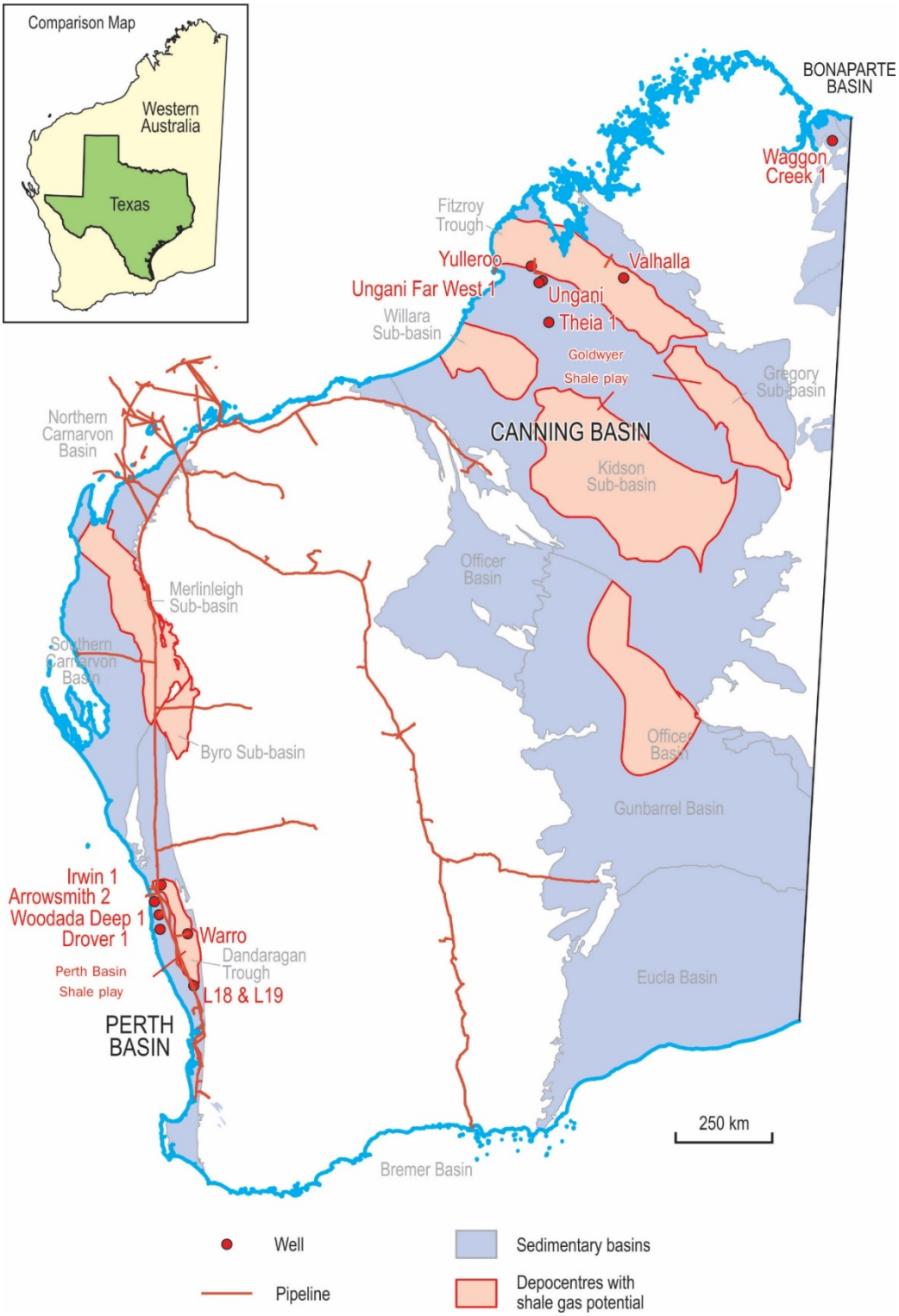

Figure 12. Tight gas and oil search in Western Australian basins, a geographic distribution.

Paleozoic Canning Basin

The Canning Basin is the largest onshore basin in Western Australia (Figure 13) with the highest estimated tight shale and sand petroleum resources within the Ordovician Goldwyer (shale) and Carboniferous Laurel (sand) formations.

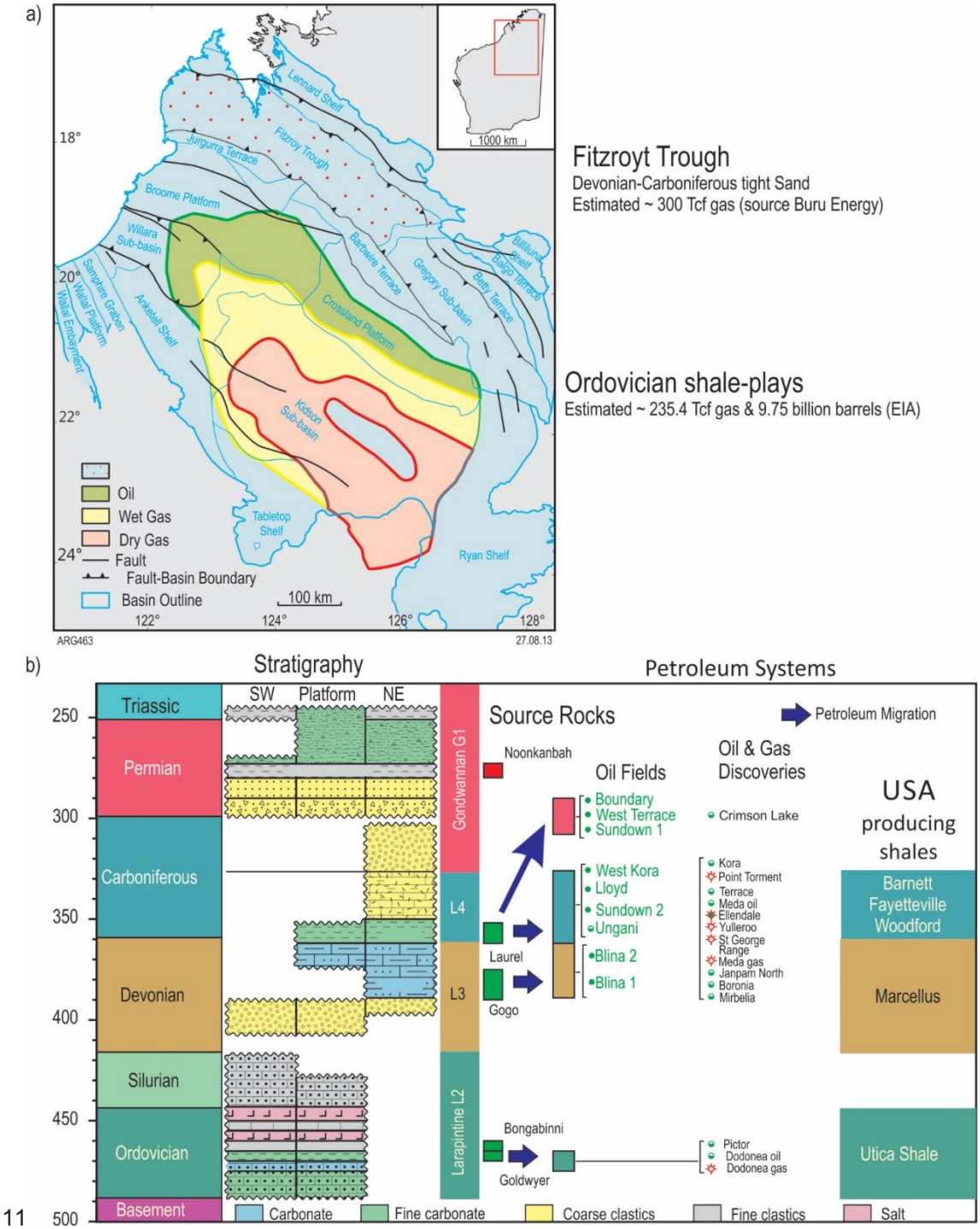

Figure 13. Tight gas and oil search in Western Australian Canning Basin: a) geographic distribution and; b) stratigraphic position.

Kuuskraa et al. (2013) estimated shale-gas resources of up to 229 Tcf of gas and 10 billion barrel of oil for the Ordovician Goldwyer Formation, Foster et al. (1986) estimated more than 61 billion barrels of generating capacity for the richest oil-prone source beds in the upper Goldwyer Formation on the Barbwire Terrace. For the eastern Canning Basin, Wulff (1987) estimated ultimate cumulative petroleum generative potential for the Goldwyer Formation at about 46, 170 million barrels per cubic mile (11,079 million barrels per cubic kilometer. These estimates indicate that the petroleum generating potential of the Goldwyer Formation is higher than the Canning Basin (Ghori, 2013).

Since 2008, about nine vertical wells have been drilled by Buru Energy to test potential tight-sand gas reservoirs within the Carboniferous Laurel Formation, and only one (Yulleroo 2) well have been fractured at three levels. Additionally, only three vertical wells have been drilled by New Standard to test the shale-gas potential of the Ordovician Goldwyer Formation, but none were fractured.

The Canning Basin is huge, under-explored and very remote without infrastructure that can support exploration and development of petroleum resources. Thus, it will take some time to explore and develop its huge estimated tight-reservoir petroleum resources.

Paleozoic-Mesozoic Perth Basin

The Perth Basin forms a north–south elongate rift trough along the west coast of Australia (Figures 14 and 15), which is the second highest oil and gas producer within the Western Australian jurisdiction. Recent discoveries of the Senecio and Waitsia fields (Figures 14 and 15) have added significant new petroleum resources. Current petroleum production is from conventional reservoirs; from tight-sand reservoirs within the Irwin River Coal Measure of Corybas Gas field is present.

The Permian, Triassic, and Jurassic source rocks have the potential to form self-sourcing reservoir systems, of which petroleum resource estimates indicate significant tight sand/shale gas and oil resources. These include up to 25 trillion cubic feet (Tcf) of gas in the Permian Carynginia Formation (Figure 16), and up to 8 Tcf of gas with 500 million barrels of oil/condensate in the Triassic Kockatea shale (Kuuskraa et al., 2013). Production from conventional reservoirs in 2014 comprised more than 1,155 barrels of oil, 104,324 barrels of condensate, and 7.335 billion cubic feet of gas, the latter two of which are locally significant and indicate the potential gas-condensate rich resources.

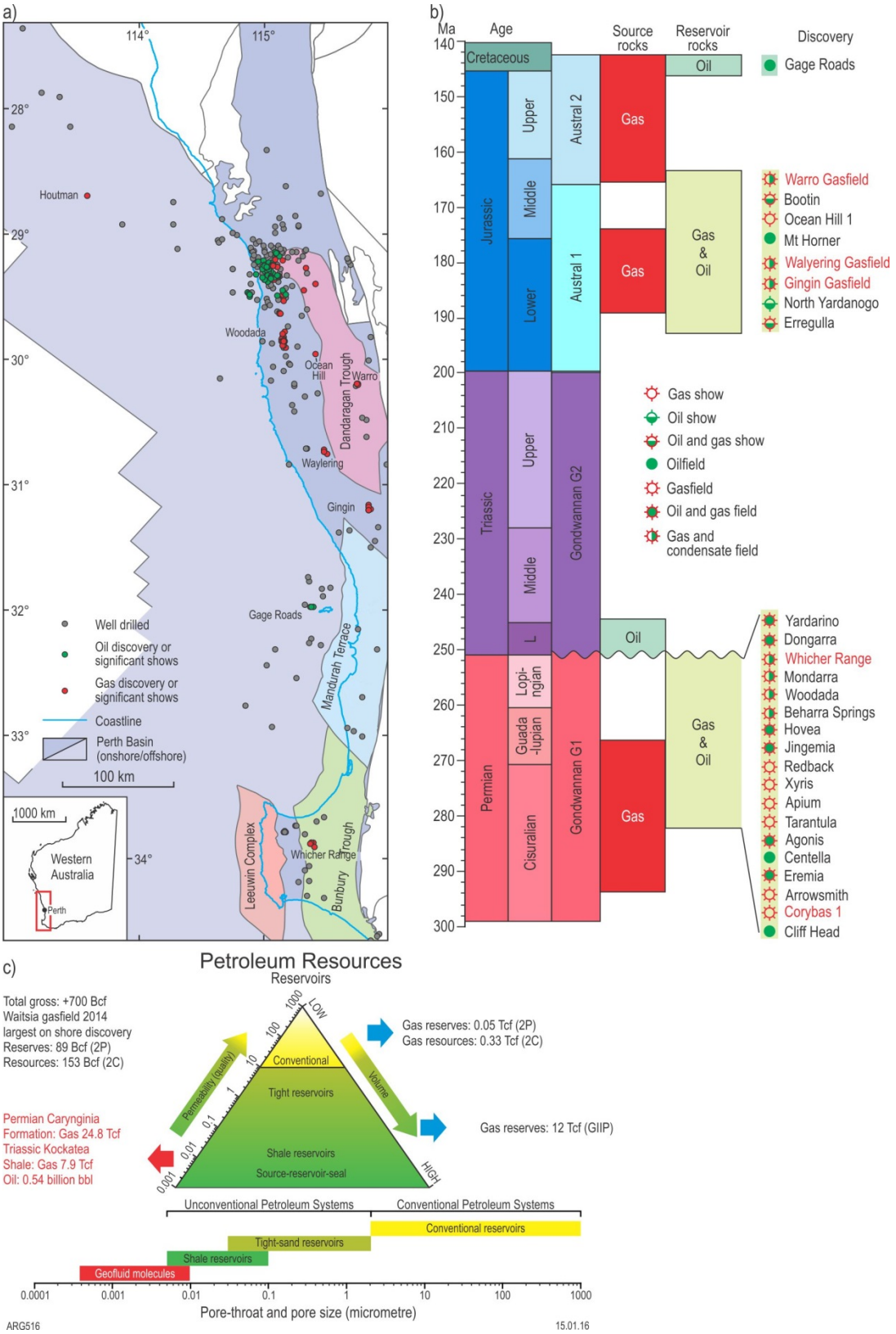

Figure 14. Summary of the Perth Basin: a) location, tectonic units, petroleum wells and discoveries; b) time-stratigraphy, petroleum systems, source rocks, reservoirs, and discoveries; c) distribution of reservoirs and resources.

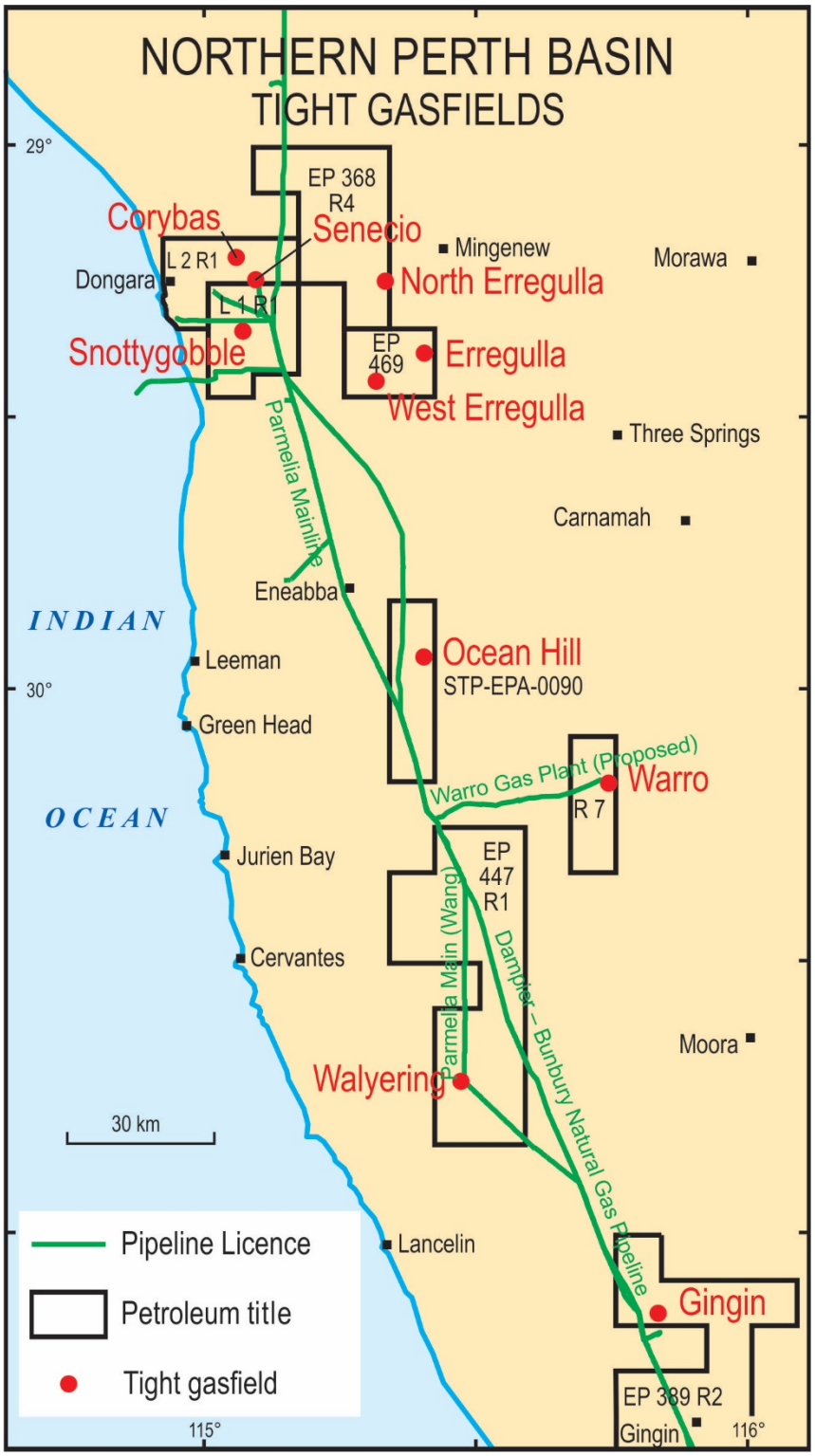

Figure 15. Summary of tight gasfiled discoveries and pipelines in the Perth Basin.

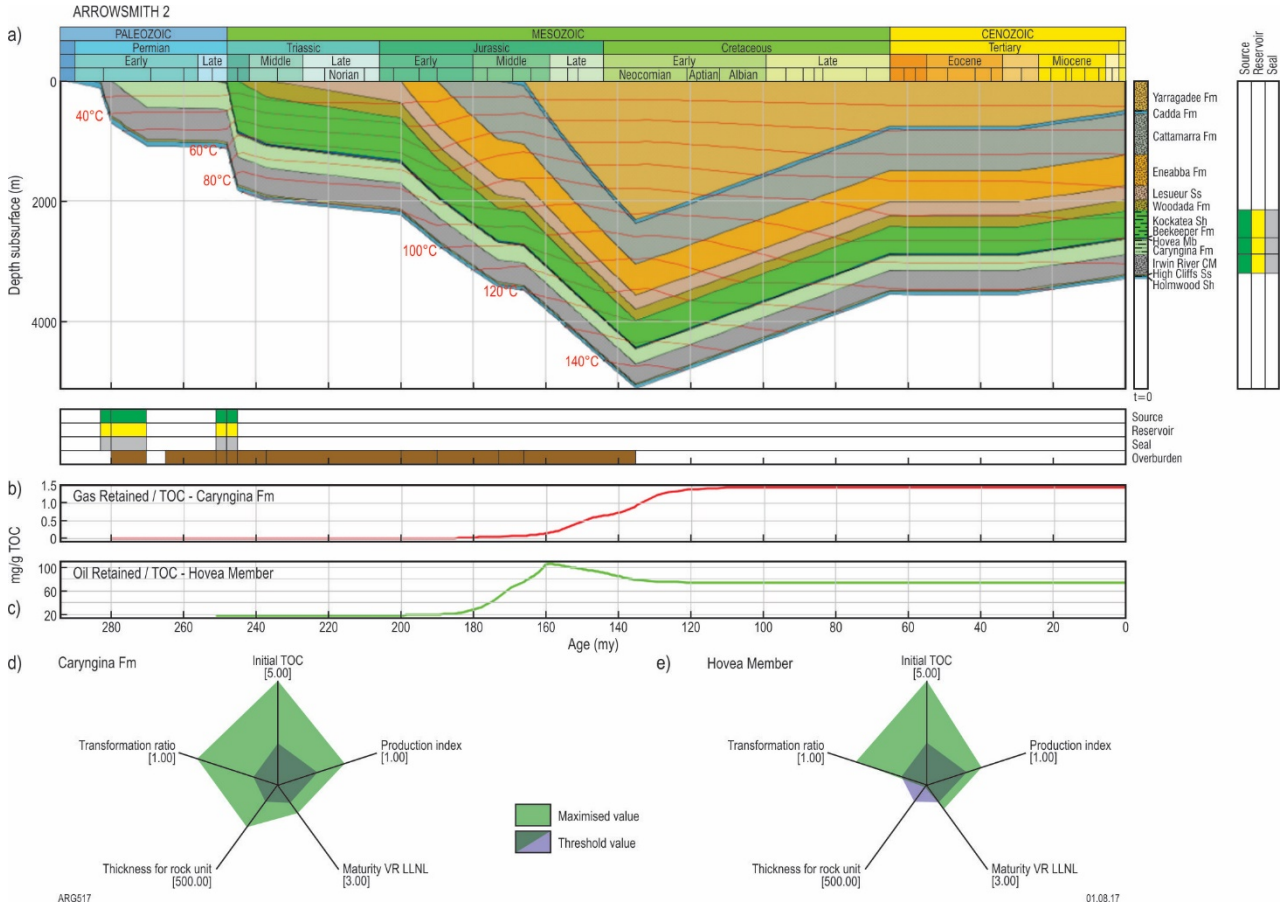

Figure 16. Summary of the petroleum systems of Arrowsmith 2; (a) burial and thermal history, and petroleum system elements; (b) gas retained in the Permian Carynginia Formation source rocks; (c) oil retained in the Triassic Hovea Member source rocks; (d) Carynginia Formation source richness, maturity and thickness; (e) Hovea Member source richness, maturity and thickness

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STATUS OF CANADA TIGHT GAS ACTIVITY

The National Energy Board of Canada (NEB) recently published an energy market assessment on natural gas production in Canada titled 'Canada's Energy Future 2017 Supplement' (https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017ntrlgs/nrgftrs2017spplmntsntrlgs-eng.pdf).

Most of the tight gas production in Canada comes from the Western Canada Provinces (NEB 2018). Peak production of tight gas in Alberta is significantly reduced by about 4 Billion cubic feet per year (Bcf/yr) from 2004 to late 2017. British Columbia production is about the same or rises slightly over an equivalent time period, while Saskatchewan tight gas from the southwestern portion of the province also decreases significantly.

As listed in the report, the analysis includes production from the following strata: Alberta (Colorado Group, Mannville Group, Jurassic, Triassic (non-Montney), and Montney; British Columbia (Colorado Group, Mannville Group, Jurassic, Triassic (non-Montney), Montney, Permian, Mississippian, and Devonian), Saskatchewan (Colorado Group, Mannville Group, and Mississippian). The NEB definition of tight gas includes low permeability sandstone, siltstone, limestone or dolostone reservoirs. Shale gas and conventional gas production are not included in Figure 1.

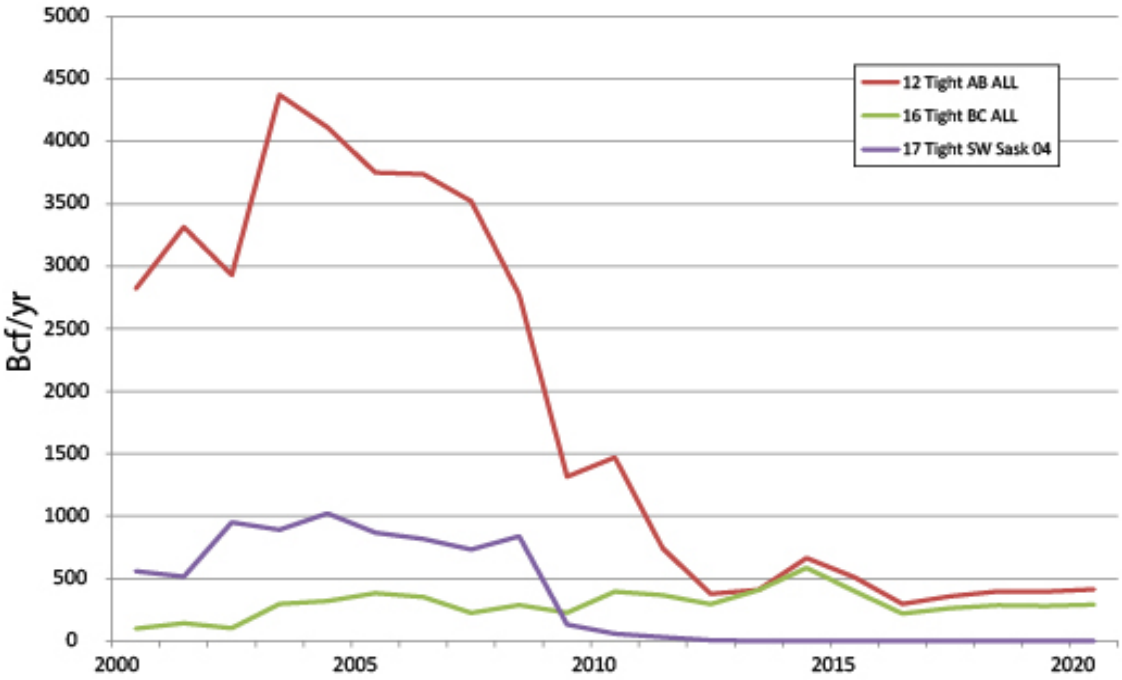

Figure 1. Graph of tight gas production in Western Canada to November 2017 with a projection to 2020 (NEB 2018). The NEB report projected production to 2050 but the data has been cutoff at 2020 for this summary report.

Tight Gas in the Western Canada sedimentary basin has been studied and tested at least from the late1970s (Masters 1979). Masters concluded that tight gas in the Deep Basin of Alberta and British Columbia is trapped down-dip of free water with no impermeable barrier between them. Subsequent work extended the plays outside of the deep basin to the Foothills and thus the tight gas plays were determined to be more regional in extent (Hayes 2003). What follows is a summary of a few of the more notable tight gas formation in the Western Canada Sedimentary Basin.

Cretaceous, Deep Basin of NW Alberta and NE British Columbia

Within the Cretaceous sequence of rocks of the Deep Basin some 12 zones are potentially gas saturated in low porosity and low permeability siltstone, sandstone and conglomerates (Masters 1984). Early work looked for sweet spots in these reservoirs, but at present 4-5 zones, rarely higher, are fractured and production is commingled in a 'Development Entity', as designated by the provincial energy regulator (Hayes 2009). The Development Entity encompasses strata from the Upper Cretaceous Smoky River Group to the Middle Jurassic Rock Creek Member. Multi-zone commingling allows operators to complete numerous zones in a single vertical well without having to run pressure or flow tests, specified by the regulator, across each formation, thus reducing costs.

Drilling in the Spirit River Formation, consisting of the Notikewin, Falher and Wilrich Member tight sands and shales, continues to be successful; Spirit River is one of the most drilled formation during 2017 in the Western Canada Sedimentary Basin. Over the past 5 years drilling in the Deep Basin for Spirit River production dominantly covers an area of about 220 miles by 50 miles (350 km by75 km). Horizontal wells increased from about 50 wells in 2010 to about 2500 wells in 2017 (https://www.gljpc.com/blog/understanding-gas-initially-place-and-deliverability-spirit-river). Permeability is about 0.01 to 3 md with porosity ranging from 6 to18% according to Bellatrix Resources online data. Encountering a permeability-rich interval (channel?) is also possible and provides some of the highest gas flow rates in the Deep Basin. **According to an IHS Markit analysis,** the breakeven point is about $2/mcf (Cdn) owing to shallower wells and hence lower horizontal drilling and completion costs. Wells in the play are relatively liquid-rich, roughly 5 to 20 bbls/mmcf with EUR ranging up to 20 Bcf.

Cardium Formation, Western Canada Sedimentary Basin, Alberta, Canada

The Cardium Formation in Alberta continues to be active for tight gas, liquids and oil. The focus is primarily on the liquids-rich gas or tight-oil held in the fine-grained fringe deposits (or 'haloes') of long time, producing conventional deposits. The Cardium Formation hosts about 25% of Alberta's discovered conventional oil with >10 billion barrels (BB) of oil-in-place, and cumulative production (from 1957 to 2009) of ~1.75 BB. A recovery of only 17% of the pools has been accomplished using conventional vertical drilling and completion strategies, and a combination of primary and enhanced oil recovery (EOR). Beginning in late 2008, there has been significant redevelopment of the Cardium Formation using multi-stage horizontal wells and hydraulic fracturing. Production has significantly increased by renewing development in under-developed areas of the conventional pools,by new development on the fringe of the conventional pools and by drilling horizontal wells into the prodelta silt and sands. Cardium reservoirs typically occur at depths between 3,937–9,186 feet (1200–2800 m) and mainly produce light oil with varying amounts of dissolved gas in the south, along with of liquid-rich gas in the north.

Drilling in the Cardium play increased in 2018 with drilling up about 25% over 2017 to 340 wells. The Cardium play had an initial sharp increase in horizontal drilling and completion beginning in 2009, largely focused on the Pembina and Garrington fields of central Alberta where light oil was targetted in haloes surrounding the conventional oil fields. Drilling dropped to low of 124 wells in 2016, increasing to 273 wells in 2017. The Cardium occurs at 4,265 feet (1300 m) vertical depth at Pembina, and 5,905 feet (1800 m) vertical depth at Garrington.

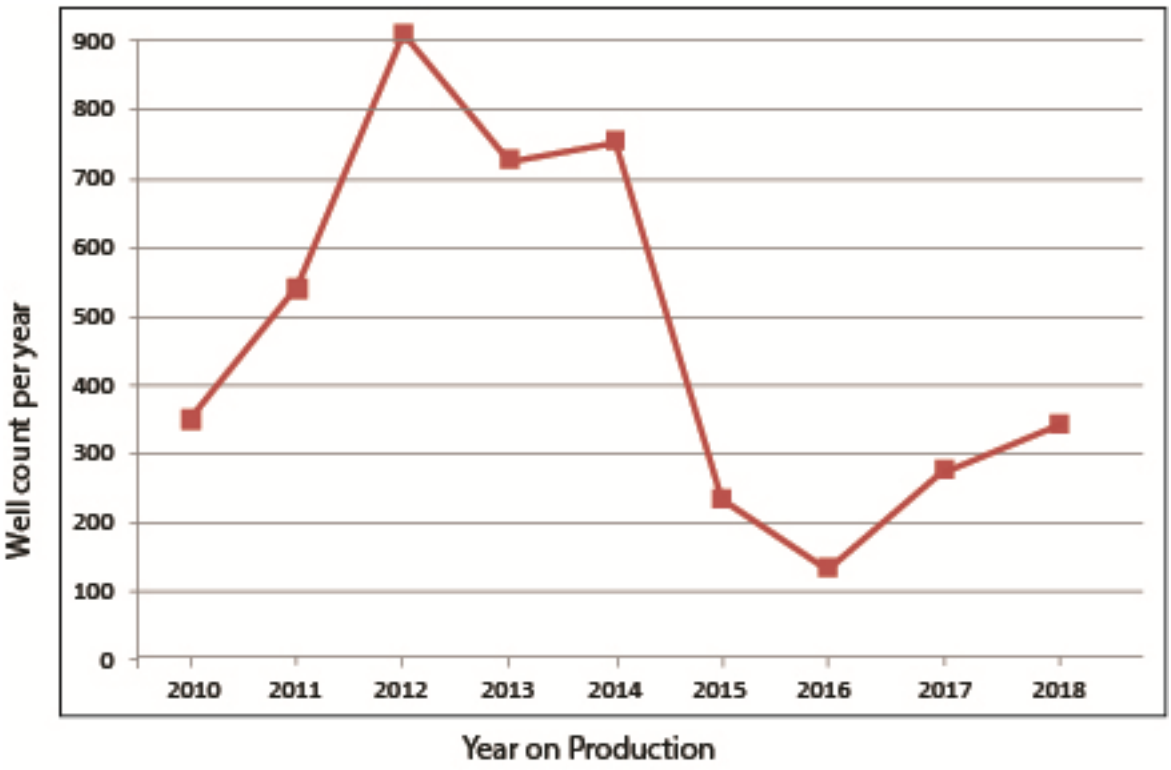

Figure 2. Drilling statistics to the end of September 2017 for the Cardium Formation indicate an increase in activity from a high of 590 wells producing in 2012 to a low of 49 well producing in 2016. The amount of producing wells more than doubled in 2017 to 110 wells and in 2018 increased over 600% to 622 wells.

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STATUS OF CHINA TIGHT GAS ACTIVITY

China's natural gas use rose about 15% during 2017. Natural gas accounts for 6 percent of China's energy demand (as of 2016), double the market share in 2007 (https://www.export.gov/article?id=China-Oil-and-Gas), owing to "strategic national importance and lower carbon intensity" (https://www.woodmac.com/press-releases/new-wave-of-growth-on-the-horizon-for-asia-pacifics-oil-and-gas-sector/). China is projected to become the world's top importer of natural gas during 2019. According to the IEA (Gas 2018) Chinese natural gas imports are projected to incease by 60% between 2017 and 2023; imports increased 28.3% year-on-year as of September 2018 (https://oilprice.com/Energy/Crude-Oil/China-To-Boost-Shale-Oil-Gas-Production.html).

Tight-gas sandstone exploration started during the 1970s in China. Tight-gas sandstones are widely distributed in a number of basins including the Ordos, Hami (including the Taibei Depression, located in the Tu-Ha Basin, also called the 'Turpan-Hami' Basin), Sichuan, Songliao, Tarim, and deeper parts of the Junggar Basin (Figure 6, Table 1). The prospective areas of these basins exceed 300,000 km^2. In early 2012, tight gas sands were considered one of the most promising unconventional resources in China. This is largely due to three factors: 1) the confirmed assessments of the tight gas-sands resource in China; 2) the advanced state of technological development for tight gas sands production; and, 3) the distribution of tight gas-sands in many areas previously developed for conventional gas plays, with existing infrastructure in place.

According to Zou et al. (2018), tight gas production 'broke through" in 2005, reached 1.0594 x 10^{12} ft^3 (300 x 10^8 m^3) in 2012 and increased to 1.211 x 10^{12} ft^3 (343 x 10^8 m^3) in 2017, accounting for 23.7% of China's total natural gas production. This value, at present, is significantly more than shale production in China which in 2017 is about 6% of total production.

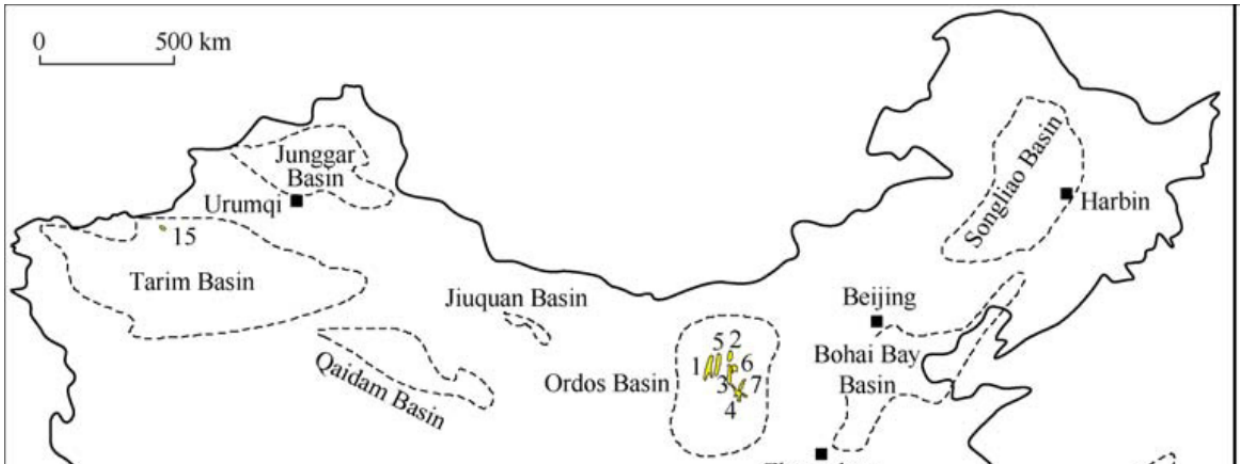

Figure 5. Distribution of large, tight Gas Fields in China (Hao et al 2007).

Table 1. Table of Properties of the Main Tight Gas Fields in China (Dai et al. 2012). Note- the Sulige Gas Field Reserves were increased in 2015 to 44938 Bcf (12725.8 E8 m^3) with an annual output of 749.4 Bcf (212.2 E8 m^3) (Dai et al. 2015).

Basin	Field	Reservoir Type	Reserves (2010) (10^8 m^3)	Reserves BCF	Annual Output (10^8 m^3)	Annual Output Bcf	Mean Porosity (%)
	Sulige		11008.20	38875	104.75	369.92	7.163
	Daniudi		3926.80	13867	22.36	78.96	6.628
	Yulin		1807.50	6383	53.3	188.23	5.63
Ordos	Zizhou	Continuous	1152.00	4068	5.87	20.73	5.281
	Wushenqi		1012.10	3574	1.55	5.47	7.82
	Shenmu		935.00	3302	0	0.00	4.712
	Mizhi		358.30	1265	0.19	0.67	6.18
	Hechuan	Continuous	2299.40	8120	7.46	26.34	8.45
	Xinchang	Trap Dominated	2045.20	7223	16.29	57.53	12.31/
	Guang'an	Continuous	1355.60	4787	2.79	9.85	4.2
	Anyue	Continuous	1171.20	4136	0.74	2.61	8.7
Sichuan	Bajiaochang	Trap Dominated	351.10	1240	1.54	5.44	7.93

	Luodai	Trap	323.80	1143	2.83	9.99	11.8
	Qoingxi	Trap Dominated	323.30	1142	2.65	9.36	3.29
Tarim	Dabei	Trap	587.00	2073	0.22	0.78	2.62

Below are a few examples of tight gas product ion from three basins in China.

Ordos Basin

The China National Petroleum Corporation, updated reserves in the Sulige Gas Field in 2015 to 44938 Bcf (12725.8 E8 m^3) with an annual output of 749.4 Bcf (212.2 E8 m^3) (Dai et al. 2015. Well more than 5000 wells have been drilled into the Sulige Tight Gas Field in the Ordos Basin of Inner Mongolia, north central China. The field has a potential area of 40,000 km^2, The field is characterized by low permeability and low pressure. The Sulige Gas field is reported to be a stratigraphic trap developed in Permian sandstone at a depth ranging from 3200 to 3500 meters. Induced fracturing occurs in three separate zones in the sandstone which are commingled for production. Wells have an average permeability to air of 0.1–2.0 mD and exhibit a rapid pressure drop after initial production. In addition, the Ordos Basin produces the most gas in China, as of 2013 at 1.343 Tcf (379.63 × 10^8 m^3), contributing 31.4% to China's total annual gas production (Dai et al. 2015).

Turpan-Hami Basin

The lower Jurassic Shuixigou Group sands in Turpan Depression, Turpan-Hami Basin southeast of the Junggar Basin contains three stacked successions of tight-gas sandstones (1640–3609 feet or 500–100 m thick) within braided-delta–front reservoirs that debouched into a largely lacustrine basin and are associated thick coals. Burial depths of the tight-gas sandstone reservoirs range from 9,186–14,108 feet (2,800–4,300 m). The field produces from a series of stacked sand-pebbly sand, interpreted mainly as subaqueous braided delta front channel-fills, with porosity of 4–8.4 % and permeability of 0.077–3.61 mD. Within the three gas-bearing successions, individual sand reservoirs range from 59–180 feet (18–55 m), with a gross thickness of the stacked successions between 344–919 feet (105–280 m). The play seeks to exploit naturally-fractured reservoirs with the highest production from fractured (micro- and macro-scale) reservoirs on structural highs, and the lowest production in the relatively unfractured zones within adjacent structural lows. Single well gas productions vary from 1.9–7.6 x 10^4 m3/d. Natural gas traps are conventional and consists of combined stratigraphic and structural traps, including faulted anticlines and fault block horst-and–graben structures. The high-production tight-gas sandstone reservoirs are largely controlled by the tectonic setting of the area and the nature of the natural fracture/fault system. The most favorable areas for tight gas are located on structural highs with a high density of fractures and thick coals (66–98 feet or 20–30 m thick) capping the sandstones. The second-most favorable areas are located also on structural highs with a high fracture density, but where the thickness of the sandstone, pebbly sandstone and capping coals are variable. The geological factors that control the productivity of single wells within the typical tight-gas reservoirs relate to the structural location, sedimentary facies, density of natural fractures, and close proximity to thick and continuous capping coals.

Junggar Basin

The USGS (Potter et al. 2017) estimated undiscovered, technically recoverable mean resources of 764 million barrels of oil and 3.5 trillion cubic feet of gas in tight reservoirs in the Permian Lucaogou Formation in the Junggar Basin (Fig. 5) of northwestern China. The focus of the assessment was tight reservoirs interbedded with organic-rich shale of the lacustrine Lucaogou Formation. According to the USGS report there were “16 wells producing “industry tight-oil flows” from the Lucaogou Formation”.

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Oman Tight Gas Activity

The Khazzan natural gas field located northern Oman was discovered in 2000 by BP and began production in 2017 (BP 60%, Oman Oil Company 40%). The field is termed a tight gas 'giant' with an estimated 10.5 trillion cubic feet of recoverable gas resources, 7 TCF of recoverable reserves. The first phase of development is expected to yield about 1.0 Bcf/d natural gas and about 25,000 barrels per day of gas-condensate from 200 wells with production climbing to 1.5 Bcf/d after phase two from a total of about 300 wells. A variety of frac types have been attempted including million lb. cross linked gel fracs and 50,000 bbl slick water fracs.
Production comes from the Cambrian Barik sandstone at a depth of about 14,000 to more than 16,000 feet from a transition of continental, fluvial braid-plain and shoreface to offshore mudrocks within a combined stratigraphic/structural trap (Millson et al. 2008). A complex network of largely secondary porosity may control productivity. The sandstone is largely quartz cemented however feldspathic-rich intervals seem to have better overall reservoir quality. The presence of bitumen suggests that early hydrocarbon charging may have preserved reservoir quality rock. Helium porosity measurements range up to 24% in select fluvial facies however the arithmetic mean range is about 4% in distal offshore facies to about 9% in fluvial facies. The geometric mean of horizontal permeability measurements ranges from 0.06 md in distal offshore facies to 0.l56 md in fluvial facies.

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Egypt Tight Gas Activity

According to Salah et al. (2016), the Appollonia Formation is a carbonate reservoir that overlies the Late Cretaceous Khoman Formation. The formation consisting dominantly of realtively soft, high porosity chalk and low perameability limestone. An initial pilot stage of vertical drilling with small scale fracturing indicated the presence of gas although in relatively low flow rates that could not be sustained. A program of foam fracing yielded 1-2 MMcf/d from the vertical wells, increasing optimism that the reservoir is economic. During 2016, two horizontal wells were drilled and hydraulically fractured increasing flow rates to 7 MMcf/d,

stabilized after 120 days. As of early 2017, a third well will be drilled and the field is under investigation to assess the feasibilty of long term success.

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STATUS OF OTHER AREAS IN THE WORLD

There are tight deposits in many other areas of the world and our objective Is to continuously update this report.