HOW ARE ONSHORE LICENSING REGIMES IN AUSTRALIA DEALING WITH
THE CHALLENGES OF PETROLEUM IN SHALE AND OTHER TIGHT ROCKS?

John Chandler

This article examines how the onshore petroleum legislation in Australia deals with some of the challenges posed by unconventional petroleum produced from shale and other tight rocks. It focuses on the delineation of the extent of the resource and its appraisal and feasibility testing, which often involves production from a pilot plant.

Introduction

Until relatively recent times, exploration and production of petroleum were focused on conventional petroleum reservoirs; that is, those containing commercial quantities of petroleum in porous rock, surrounded by impermeable strata, which prevents the petroleum from escaping. Extraction of commercial quantities of petroleum from shale and other tight rocks is a relatively recent phenomenon resulting from the development of combined horizontal drilling and hydraulic fracturing (“fracking”) techniques in the 1990s. So in the period from the drilling of the first commercial petroleum well in Pennsylvania in 1859, the focus of regulators and those drafting Joint Operating Agreements (JOAs) has largely been on conventional reservoirs. Production of petroleum from shales and other tight rocks is often described as unconventional. It is not the petroleum that is unconventional, although it is sometimes described as “unconventional petroleum”; it is the rock from which it is extracted, or “the play”. Opinions on the correct terminology differ. For some, the focus of this definition is exclusively on the source rock, while others emphasise the source rock and the enhanced technology used in production, or other factors.

This article examines how the onshore petroleum licensing regimes of the Australian states and the Northern Territory are responding to some of the challenges posed by the exploration and production of petroleum from shale and tight rocks. The article focuses on the delineation of the extent of the resource and its appraisal and feasibility testing, which often involves production from a pilot plant.

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1 Professor, University of Western Australia.
2 This was largely through the work of Mitchell Energy in the Barnett shales in Wise County Texas.
4 The expression “play” is used in the industry to describe an area in which hydrocarbon accumulations or prospects of a given type occur, or more specifically as “a conceptual model for a style of hydrocarbon accumulation used by explorationists to develop prospects in a basin, region or trend and used by development personnel to continue exploiting a given trend. A play (or a group of interrelated plays) generally occurs in a single petroleum system”. See Schlumberger Oilfield Glossary, http://www.glossary.oilfield.slb.com/en/Terms/p/play.aspx. The Alberta Energy Regulator describes a “play” as follows: “A resource play is an accumulation of hydrocarbons over a large area deep beneath the surface of the ground. Its geology and geographic setting define the characteristics of the play and how it is likely to be developed.” https://www.aer.ca/documents/about-us/PBR_Brochure.PDF.
5 T Hunter and J Chandler, Petroleum Law in Australia, (LexisNexis Butterworths, 2013) 5. See, for example, also the CSIRO note on “What is unconventional gas?”, http://www.csiro.au/en/Research/Energy/Hydraulic-fracturing/What-is-unconventional-gas. Both the initial paragraph and the paragraph “How are GSG and conventional natural gas different?” link the geology and production method in respect of both coal seam gas and shale gas.
Terminology

Shales are dense clay-rich rocks and other tight rocks including highly compacted and cemented siltstones, sandstones and carbonates (limestones and dolostones). These rocks can produce gas, oil and other liquids. While the gas is mainly methane, it can also contain other gases such as ethane, propane and butane. One important difference that needs to be borne in mind is that conventional petroleum reservoirs are characterised by a greater degree of porosity and permeability of the reservoir beneath the impermeable cap rock, and a higher level of pressure within the reservoir caused by gas or water pressure. This reservoir is often described as a petroleum pool. While the petroleum is still trapped in pore spaces in the rock, there is hydrostatic and pressure communication within the reservoir. This means that petroleum moves towards a well that produces from the reservoir (that is, towards pressure depletion).

Operations in relation to shale and other tight rocks have a number of points of difference from conventional petroleum play operations. The lack of permeability of shale means that a well that is drilled into shale will drain a much smaller area and suffer a more rapid decline in the rate of production than a conventional well, even with the benefit of horizontal drilling and fracturing. This means that many more wells have to be drilled to maintain a commercial rate of production. But shale strata can extend over much larger areas than a conventional petroleum pool. Further, the strata may not be consistent. So exploration and appraisal will be ongoing activities even where production has commenced, as new production wells have to be drilled to maintain the rate of production. The first discovery of an accumulation of shale petroleum is unlikely to be a sufficient basis for a decision to proceed to production. Also it would be possible to have multiple discoveries in a licence area, with no single discovery being commercial. Depending on the geology, many of the same comments can be made about operations in relation to tight rocks. However, although tight oil and gas are found in low-permeability rocks, there can be situations in which they are found in pools. Generally petroleum in tight rocks and shale is found somewhere between 2000 and 5000 metres below the surface.

For these reasons, the delineation of the extent of the resource is more difficult than for conventional petroleum. Also development of petroleum from shale or tight rocks usually has a stage for proof of concept, where the feasibility of maintaining commercial rates of production is tested. This will often involve drilling a number of wells and then testing the flow rates from the wells and, perhaps, selling the product from a pilot plant. One of the issues this article will examine is how the

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6 Schlumberger’s Oilfield Glossary defines a “conventional reservoir” as: “a reservoir in which buoyant forces keep hydrocarbons in place below a scaling caprock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellsbores. The term is used to make a distinction from shale and other unconventional reservoirs, in which gas might be distributed throughout the reservoir at the basin scale, and in which buoyant forces or the influence of a water column on the location of hydrocarbons within the reservoir are not significant.” See also the definition of “petroleum system”: www.glossary.oilfield.slb.com.
9 In a recent publication Shale and Tight Gas in Western Australia A Whole-of-Government Approach (2015 edition) published by the Department of Mines and Petroleum in Western Australia, the proof of concept
licensing regimes of the Australian states and the Northern Territory deal with this, given that licences are issued for different stages of operations. This raises questions such as whether it is permissible to produce petroleum and sell it under an exploration permit or retention lease. This is because the petroleum legislation of the states and Northern Territory generally prohibits commercial production without the requisite licence, which is normally a production licence.

This article does not deal with how JOAs deal with these matters. Two model JOAs commonly used in Australia are the Association of International Petroleum Negotiators draft Unconventional Resource Operating Agreement (AIPN UROA)\(^\text{10}\) and the AMPLA Model Petroleum Joint Operating Agreement (AMPLA PJOA).\(^\text{11}\) It is worth noting what the Guidance Notes to the AIPN UROA say about the practical nature of the problem:

- In unconventional resource development, parties need to be able to
  - Delineate the extent of the resource play
  - Conduct a pilot program to determine whether the production technology and methodology in light of the resource characteristics is effective and commercial before committing to a broader long term development plan
- Contract [for which in Australia read ‘Licence’] needs to clarify whether a pilot program is part of appraisal or part of exploitation\(^\text{12}\)

The Notes then go on to explain that there are at least two paths to commerciality. Putting the language into an Australian context, this means that if the licence allows production before the issue of a production licence, then the sequence would be an appraisal program including delineation of resource and then a pilot program. But if the licence does not allow production, then the sequence would be an appraisal program that delineates the resource followed by transition to a production licence of which the first phase is a pilot program.\(^\text{13}\) As readers will see, the legislation in some states in Australia tends to force the explorer to the second path because it is an offence to produce petroleum commercially without a production licence. This may not be desirable for a number of reasons, principally because the production methodology has not been tested. So as an approach it seems illogical. But going beyond that it may be premature because the delineation of the resource may be ongoing, with more work being done in conjunction with running the pilot plant.

**Challenges in dealing with unconventional petroleum operations**

What this is highlighting is a difference of approach between conventional and unconventional petroleum operations. The licensing regimes and JOAs have generally reflected the former. Some of the main principles in the petroleum statutes of the states and the Northern Territory were set

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\(^\text{13}\) See the Guidance Notes, 3.

The AIPN UROA assumes an underlying contract like a production sharing contract. This is a single contract with phases for exploration and exploitation (and sometimes development) that can apply to different areas in the contract. The AIPN UROA assumes that the move from one to the other involves a declaration of commerciality in regard to an area to be developed and the preparation of a development plan and its acceptance by the government entity administering the contract. The Guidance Notes for the AIPN UROA are a valuable resource for explaining these kinds of differences.
over 40 years ago, although Queensland and South Australia completely revised their petroleum legislation in the early 2000s. Conventional petroleum operations are characterised by a staged approach of phases: exploration, appraisal of a well once a discovery has been made, development of the necessary facilities, production and finally decommissioning. With conventional petroleum, an individual well can drain the equivalent of hundreds of acres and sustain an economic operation. Accordingly, the judgment of when commercial production is geologically feasible, and whether to transition to a production licence, is more clear cut than for unconventional petroleum. As noted above, with unconventional petroleum multiple wells may have to be drilled and tested to come to that conclusion. Also the lines between the phases can become blurred or overlap in shale and other tight-rock operations. This means that regulators have to balance their traditional policy stances on matters like area relinquishment, fixed sizes for licence areas, compulsory work programs and transition to a production licence with the additional flexibility required by those conducting unconventional operations.

Petroleum operations from shale and other tight rocks face two other major challenges, which lead to broader questions in relation to their regulation, and which are too extensive to deal with in this article. However, they should be raised to explain the overall context. The first is infrastructure. Australia has suffered a perennial shortage of infrastructure in the places where petroleum is found and this highlights another set of problems. Shale and other tight-rock operations are accompanied by increased use of roads because of the movement of plant and machinery involved in drilling and fracturing, the drilling of numerous wells, the supply of the large amounts of water required in fracturing, the disposal of waste water and the need for gas pipelines. Except perhaps in relation to the development of coal seam gas (CSG) in Queensland, Australia is yet to experience the intensity of operations that has been experienced in parts of the United States and Canada.14

The importance of infrastructure is one of the reasons why Alberta is looking at changes to its regulatory structure and piloting play-based regulation. As is explained in the discussion paper leading to this pilot: “For example, unlike conventional hydrocarbon pools, unconventional resource development requires a greater scale of development and intensity of infrastructure (wells, roads, and other facilities) to be economical. This difference, and others, is driving the ERCB’s work to introduce a new regulatory framework for the development of unconventional resources.”15

However, there is a critical difference between Alberta, the United States and Australia, and that is that rights to petroleum are often not subject to a licensing regime because they are in private or state ownership, and ownership rights are governed by a contract, such as a mineral lease. This means that the regulation of operations, including infrastructure and resource management, is separate from the ownership of the resource and the legal structure giving access to it.

**The focus of this article**

The focus of this article is on particular aspects of the licensing regime rather than on the regulation of operations. Having appropriate licences and licence conditions is considered very important by industry, and underpins sound development and production of the resource.16 Australia also has

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14 One commentator has said that the rate of development in the United States has involved four to 25 wells per square kilometre. On a graticular block of 80 square kilometres, this suggests between 320 and 2000 wells. See WJ Tinapple “Shale and tight gas in Western Australia and regulatory reform”, (Paper presented to the Petroleum Exploration Society of Australia, Western Australian Basins Symposium, 2013).
16 The number-one recommendation in the *Roadmap for Unconventional Gas Projects in South Australia* was that “Exploration, Retention and Production Licences need to have terms (in years), area and conditions
regulatory approvals for petroleum operations in relation to shale and other tight rocks. These include environmental, water, land use and Aboriginal heritage approvals, as well as requirements for community consultation. In many cases the Minister responsible for licensing administers those regulations, so there is potential for overlap between the two, and a possible opportunity to make sure that resources are developed in the most efficient manner possible. It is beyond the scope of this article to develop how that could be done. Optimal selection of licence areas to be offered, which consider how the characteristics of petroleum differ from shale and tight rocks, is one example of an idea that could be considered, perhaps keeping some areas back until the play characteristics are better known. Also if a play is spread across several licence areas, compulsory unitisation could be a consideration, including placing a condition on exploration permits requiring unitisation on set terms.17

The second challenge for these operations is community concerns about fracking and its impact on water and the environment generally. Those concerns have resulted in Victoria, Tasmania and New South Wales having, or having had, bans or moratoriums on the issue of petroleum exploration permits or fracking.18 Nearly all states and the Northern Territory have had some form of inquiry into unconventional gas or fracking, or both.19 Some of these are ongoing.20 The opportunity here is to address these concerns in the licensing process. The approach taken in South Australia is particularly worth noting. While all states have some form of environmental review or require an environmental plan for fracking, South Australia’s requirement for an approved statement of environmental objectives is contained in its petroleum legislation. It is a mandatory condition of every licence that the licensee must comply with the statement.21 The process of producing it gives a full opportunity for concerns to be aired in a transparent manner.

The Australian onshore petroleum licensing regimes
With the exception of Tasmania, all the states and the Northern Territory have special-purpose onshore petroleum legislation. Tasmania deals with petroleum in its general mining legislation.22 The Australian Capital Territory does not have specific mining or petroleum legislation and is not

18 In New South Wales a freeze on applications for petroleum exploration licences expired in September 2015. A moratorium has been placed on fracking in Tasmania lasting until March 2020. There has been an indefinite moratorium placed on the issue of onshore exploration licences and fracking in Victoria.
19 Northern Territory has completed an inquiry into hydraulic fracturing. See http://www.hydrafractioning inquiry.nt.gov.au/.
21 PGE s 105.
22 Mineral Resources Development Act 1995 (Tas).
dealt with in this article. The petroleum statutes, noting the definitions used in this article to refer to them and the provisions regarding petroleum exploration permits and production licences are as follows:

- *Petroleum (Onshore) Act 1991* (NSW) (POA) — Part III Div. 2 and 5;
- *Petroleum Act 1984* (NT) (PANT) — Part II Div. 2 and 4;
- *Petroleum Act 1923* (Qld) (PAQld) — Parts 4 and 6 and *Petroleum and Gas (Production and Safety) Act 2004* (Qld) (PGPSA) — Chapter 2; 23
- *Petroleum and Geothermal Energy Act 2000* (SA) (PGE) — Parts 4 and 6;
- *Petroleum Act 1998* (Vic) (PAVic) — Parts 3 and 5; and

The starting point is that none of the licensing regimes of the Australian states and the Northern Territory give any special treatment to petroleum in shale or tight rocks. In fact none of them refer to shale or tight rocks or petroleum extracted from shale or tight rocks in any significant way. 24 All the petroleum statutes contain a definition of petroleum that comprises all naturally occurring hydrocarbons, whether in gaseous, liquid or solid state, 25 with some exclusions such as oil shale and coal. Oil shale 26 and coal are mined and so are generally dealt with in mining legislation. Subject to those exclusions, the source rock of the hydrocarbons is not mentioned. 27 As will be discussed below, it is common in petroleum legislation to use expressions like reservoir or pool to describe an accumulation of petroleum that has been discovered. Generally these expressions are not defined in the legislation. 28 The expression “discovery” is also generally not defined.

Those states with extensive amounts of coal prospective for CSG (Queensland and New South Wales) have had more of a focus on CSG than petroleum extracted from shale and other tight rocks. 29 But the licensing provisions are in the petroleum legislation, the POA and the PGPSA. The PGPSA was developed to replace the PAQld, which was considered out of date due to its antiquated drafting style and because it did not represent best practice in a number of areas. The

23 The PGPSA was intended to replace the PAQld, and the PAQld has only been kept because of native title issues associated with the transition of existing licences under it. As a general rule, applications for new tenure will be under the PGPSA. So this article will only refer to PGPSA.

24 In PGERA s 52(4A) there is a definition of tight gas for the purposes of the royalty provisions applicable to secondary licences.

25 So for example, the definition in PGERA s 5 is “petroleum means (a) any naturally occurring hydrocarbon, whether in gaseous, liquid or solid state; or (b) any naturally occurring mixture of hydrocarbons whether in gaseous, liquid or solid state; or (c) any naturally occurring mixture of one or more hydrocarbons, whether in gaseous, liquid or solid state, and any one of more of the following, that is to say hydrogen sulphide, nitrogen, helium and carbon dioxide, and includes any petroleum as defined by paragraph (a), (b) or (c) that has been returned to a natural reservoir, but excludes oil shale.”

26 Oil shale is an organic-rich and fine-grained sedimentary rock containing the organic compound kerogen. It has to be mined and treated to extract the oil from the kerogen.

27 Note that the definition in PGE s 4 has an exclusion, which says, “but does not include coal or shale unless occurring in circumstances in which the use of techniques for coal seam methane production or in situ gasification would be appropriate or unless constituting a product of coal gasification (whether produced below or above the ground) for the purposes of the production of synthetic petroleum”. There is an exception in the case of “petroleum pool,” which is defined in PAVic s 4 and PGERA s 4 as “a naturally occurring discrete accumulation of petroleum”.

28 The practices for things like well operations are different for CSG. CSG also often requires the dewatering of the coal rather than injecting water to fracture it and then dealing with the waste water. This means that the leading practice principles for CSG contained in the National Harmonised Regulatory Framework of the Standing Council on Energy and Resources can not apply to shale and tight gas without amendment.
PGPSA established a new competitive petroleum tenure regime and a new regime for CSG. Victoria has separate legislation for coal and coal seam gas in the form of the Mineral Resources (Sustainable Development) Act 1990 (Vic), the reason being that it was thought that CSG had more in common with coal mining than petroleum.\(^\text{30}\) But it should be noted in any case that operations for CSG are different from those for shale and tight rocks, because CSG often requires the dewatering of the coal to release the hydrocarbons, and coals are generally at shallower depths than shale and tight rocks.\(^\text{31}\) For this reason, CSG is not dealt with in this article.

**Licences: delineation of the extent of the resource**

A common characteristic of the petroleum legislation of all the states and Northern Territory is the requirement to hold a permit or licence to conduct exploration for petroleum. This is most commonly called an exploration permit or exploration licence.\(^\text{32}\) When the holder of an exploration permit wants to move to commercial production, the permit must be transitioned to a different permit, which authorises production in commercial quantities. This is most commonly called a production licence.\(^\text{33}\) All of the statutes contain a prohibition on conducting activity other than in accordance with a licence.\(^\text{34}\) All the states, apart from Queensland, have a holding title, which will be referred to generally in this article as a retention lease, allowing the holder of an exploration permit to hold onto an area because it is not yet commercial to develop it.\(^\text{35}\)

While there are some common themes in the way that the petroleum statutes of the states and the Northern Territory are structured, there are significant differences. To bring this out, the approaches of PGERA in Western Australia and PGE in South Australia will be compared. Comments will also be made on the approaches of the remaining states and the Northern Territory. There is a common starting point, which is that generally the relevant Minister in all states and the Northern Territory will invite applications for the grant of an exploration permit.

First, an explanation of why PGERA is so much more rigid than PGE is required. The shape of PGERA goes back to the 1967 Petroleum Agreement between the Commonwealth and the states. This resulted in the states and Northern Territory introducing legislation to cover their offshore area in the same form as the Petroleum (Submerged Lands) Act 1967 (Cth). This was intended as a common mining code for petroleum. The code set out detailed rules for the grant of titles to

\[^{30}\text{For this reason, the definition of petroleum in PAVic s 6 excludes hydrocarbons within a deposit of coal.}\]


\[^{32}\text{In New South Wales and South Australia it is an exploration licence rather than a permit.}\]

\[^{33}\text{In New South Wales it is a production lease.}\]

\[^{34}\text{In the POA s 7 it is expressed that “A person must not prospect for or mine petroleum except in accordance with a petroleum title”. Of similar type are PANT s 105; PGPSA ss 18(3), 22 and 800; PGE s 11; PAVic s 16; and PGERA s 49 expressly prohibit operations for the recovery of petroleum except under a production licence or as otherwise permitted by the petroleum legislation.}\]

\[^{35}\text{In New South Wales it is an assessment lease and in the Northern Territory and South Australia it is a retention licence. A different approach is taken in Queensland where the Minister can declare part of an ATP a “potential commercial area of the authority”. See PGPSA s 90.}\]
ensure that the states followed them.36 Because it had substantial internal waters, governed at that
time by the Petroleum Act 1936 (WA), Western Australia introduced the Petroleum Act 1967 (WA)
to cover its onshore area (including internal waters) at about the same time as the Petroleum
(Submerged Lands) Act 1967 (WA) was passed, using the same principles as the Commonwealth
legislation. It was sensible to have the same principles applying to internal and to external waters.
These principles defined permit areas by graticular blocks and required identification of blocks
containing a discovery, which resulted in the declaration of a location and which in turn set time
running within which a production licence had to be applied for. Limits were also placed on the
number of blocks in a production licence. Following the inclusion of provisions dealing with
geothermal energy, the Petroleum Act 1967 (WA) became PGERA.

South Australia did a major review of its Petroleum Act 1940 (SA), resulting in the repeal of that
Act and the introduction of the PGE in 2000. It did not closely follow the Commonwealth’s
offshore petroleum mining code. The second reading speech in the South Australian House of
Assembly indicates a major shift in regulatory approach based on principles of certainty, openness,
transparency, flexibility, practicality and efficiency, and refinements to the licensing system.37
These included making provision for smaller exploration tenements over shorter terms to facilitate
competition and confining the area of production licences to twice the size of the area underlain by
proven and probable reserves of petroleum.38

The first point of difference is that in Western Australia, New South Wales, the Northern Territory
and Queensland, areas are defined by reference to graticular blocks. Under PGERA, an application
for a petroleum exploration permit is restricted to 400 blocks.39 South Australia and Victoria do
not define areas by reference to blocks. Under PGE, the total licence area cannot exceed 10,000
square kilometres.40 Depending on latitude, a graticular block will be somewhere around 70 or 80
square kilometres.41 So 400 blocks in Western Australia would on average be 32,000 square
kilometres. There is considerable variation between the states and the Northern Territory as to the
potential size of exploration permits. This is of course not the same thing as the size of permits
actually issued. Once exploration has commenced and a discovery has been made, the holder
of the permit must notify the Minister of the discovery. This is a common feature of the petroleum
legislation in Australia. Under PGERA’s 44(1) the obligation to notify the Minister arises “when
petroleum is discovered in the petroleum permit area”. PGERA does not elaborate what is required
for a discovery. It does not require a discovery to be made by drilling a well.42

36 See T Daintith, “Discretion in the administration of offshore oil and gas”, [2005] AMPLA Yearbook 13 and T
Daintith, “Administering the Petroleum (Submerged Lands) Act: Too much discretion or too little” [2004]
AMPLA Yearbook 1.
37 South Australia, House of Assembly, (Hansard), 17 November 1999 and continuing on 29 March 2000,
%20energy%20bill%20SittingDate%3A1999-01-01..2000-10-26%20k=petroleum%20and%20geothermal
38 South Australia, House of Assembly, (Hansard), 17 November 1999, 507.
39 PGERA sub-s 31(1). In New South Wales it is 14 blocks (POA sub-s 30). In the Northern Territory it is
200 (PANT sub-s 16(3)). In Queensland it is 100 blocks (PGSA sub-s 98(7)).
40 PGE sub-s 24(2). In Victoria it is 12,500 square kilometres (PAVic sub-s 25(2).
41 Eighty square kilometres is cited by the Department of Mines and Petroleum and 70 by the South Australian
Energy Resources Division of the Department of State Development.
42 This is a common position in all the legislation. If drilling is a particular requirement (for example, for the
issue of a retention licence in South Australia, see PGE sub-s 30(1)(a)) it is mentioned separately.
It is in the steps after making a discovery where issues in delineating the extent of the resource start to emerge. They begin with is the process of determining a location. Under PGERA s 46, the permittee can nominate blocks for declaration of a location. This requires that “a petroleum pool is identified in a petroleum permit area”, in which case the permittee may nominate the block where the pool is situated, or the blocks in the permit area to which the pool extends for declaration of a location.

Before considering the impact of the determination of a location, there is a threshold issue to be dealt with – whether a petroleum pool exists. A petroleum pool is defined as “a naturally occurring discrete accumulation of petroleum”.43 If this requires hydrostatic and pressure communication, then it will be difficult for a discovery in shale or other tight rocks to satisfy this test.44

However, a different view can be taken, as there is no reference in PGERA to a requirement for hydrostatic and pressure communication. Indeed the expression “accumulation” is not defined in PGERA. On the one hand, its ordinary meaning suggests a mass or heap. It carries a sense of gathering or collecting. On the other hand, some industry definitions suggest it is the same as a reservoir or pool.45 In the absence of an indication in PGERA or the legislature’s express intent, or a mention in any background materials of a special meaning, the ordinary meaning should be applied. That would leave the question of the implication of the word “discrete” to describe the accumulation. There seems no reason in principle why an accumulation of shale gas should not be discrete, notwithstanding that it extends over a large area, larger than a conventional petroleum reservoir or pool.46

There is a practical problem that will often be faced. The shale strata could extend over an extensive area with sweet spots established by seismic survey. Should these be treated as separate accumulations and what should be their extent? It really leaves open the question of how the permittee should delineate the resource. This leads to the problem, discussed in the next paragraph, that the blocks that form the location limit the area of the production licence.

After a nomination has been made, or if the Minister is of the opinion that the permittee is entitled to make a nomination under PGERA s 46, the Minister shall make a declaration of the blocks to which the nomination relates as a location.47 What is critical about the declaration of a location is that it sets the time limit of two years from the declaration within which the permittee can apply for a petroleum retention lease or petroleum production licence.48 Failure to apply within the time limit will mean that the holder of the exploration permit will lose all its rights when the exploration permit expires. It also limits the blocks that can be included in the lease or licence.49 Each pool

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43 PGERA s 4. This definition also occurs in PAVic s 4, but it is only used in relation to unitisation and information requirements.
44 This was the concern expressed in John Chandler, “Shale gas and government agreements in Western Australia” (2014) 33 ARELIJ 44.
45 The Schlumberger Oilfield Glossary gives several meanings to accumulation: first “an occurrence of trapped hydrocarbons, an oil field” and secondly, “the phase in the development of a petroleum system during which hydrocarbons migrate into and remain trapped in a reservoir”. The PRMS Guidelines at page 191 define it as “an individual body of naturally occurring petroleum in a reservoir”, http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf.
46 This is not a matter on which the Western Australian Department of Mines and Petroleum has expressed a final view. There has been at least one presentation from the department that seems to support the industry definition approach.
47 PGERA s 47.
48 The period can be extended for up to two years. See PGERA s 50(4)(b).
49 The blocks in the declaration and the two-year time limit can be varied. See PGERA ss 47(4), 48A(4) and 50(4).
identified can be subject to a nomination for declaration of a location or they can be combined.\textsuperscript{50} This is important given the limitation on the number of blocks in a production licence, which is dealt with in the next paragraph. So the key to acquiring more production licences, and therefore a greater area, is the number of locations.

Under PGERA s 50 there is a reduction in the number of blocks that can be included in the production licence from those constituting the location. This is done according to a sliding scale. At the upper end, if nine or more blocks constitute a location, the application must be in respect of five of those blocks. At the lower end, if two blocks constitute a location, the application must be in respect of one of them. Licences can be split into primary and secondary licences, the purpose of which lies in royalty rates.

This cumbersome process goes back to 1967, and the rationale for it can be found in the second reading speech in respect of the \textit{Petroleum (Submerged Lands) Bill} (Cth) in the Commonwealth House of Representatives. The original idea was that the block where the discovery was made was to be at the centre of nine blocks constituting the licence and in “the interests of simplicity is known as a location”.\textsuperscript{51} So the location would generally consist of nine blocks. The power of the Designated Authority, which was the relevant decision-maker at that time, to nominate the blocks, if the permittee did not, was to make sure the process of allocating a licence commenced. The Minister for National Development of that time expressed this as “simply a safeguard to ensure that there is no question of a permittee who has made a discovery hanging back in the traces and delaying unnecessarily moving into the production stage”. The primary and secondary licence arrangements also originate at that time. The \textit{Offshore Petroleum and Greenhouse Gas Storage Act 2005} (Cth), the successor to the \textit{Petroleum (Submerged Lands) Act 1967} (Cth), still uses the location arrangement.

It is at the production licence stage that the reduction of blocks according to the sliding scale occurs. There is no equivalent on the application under PGERA for a retention lease. The grant of a retention lease is subject to other conditions, primarily that the Minister is satisfied that one of the blocks contains petroleum and that the recovery of petroleum is not commercially viable, but is likely to become so within 15 years.\textsuperscript{52} When it was introduced, the desire for production drove the two-year period within which an application for a production licence or a retention lease had to be made. What, in fact, occurred in a number of instances was that gas was found, which became subject to petroleum retention leases while waiting for the recovery of the resource to become commercially viable.

In contrast, the process in South Australia is a lot simpler. PGE sub-s 21(3) states that the holder of an exploration licence is entitled to a corresponding retention licence or production licence for a regulated resource discovered in the licence area. PGE s 35 provides for the grant of a production licence to the holder of an exploration licence if “a regulated resource exists in the area for which the production licence is to be granted”. A regulated resource means “a naturally occurring underground accumulation of a regulated substance”. A regulated substance relevantly means petroleum or “any other substance that naturally occurs in association with petroleum”. The expression “accumulation” is not defined in PGE (its meaning is discussed above in relation to PGERA). If a permittee can satisfy the test of having a naturally occurring underground

\textsuperscript{50} PGERA s 46(2).


\textsuperscript{52} PGERA sub-s 48B(1)(c).
accumulation of petroleum in the area of the proposed production licence, then it can obtain a production licence or production licences. Section 35 does not specify that only one production licence can be obtained. The test in PGE sub-s 35(1) is only that a regulated resource exists “in the area for which the production licence is to be granted”.

This is then elaborated in sub-s 37(1), which says that the area of a petroleum production licence must not exceed either of the following limits by being “(a) twice the area under which (according to a reasonable estimate at the time of granting the licence) the discovery is more likely than not to extend; (b) 100 square kilometres”. So a permittee can obtain up to 100 square kilometres in a single petroleum licence and is eligible to apply for contiguous petroleum production licences if the resource extends beyond that. What is interesting here is that paragraph (a) allows a flexible interpretation of the area to which the discovery extends.53 It should make delineation of the extent of the resource a lot easier. Also there is no limit to the number of production licences that can be applied for by the holder of an exploration licence. In South Australia, the provisions regarding the area of grant of a petroleum retention licence are broadly similar to those for a production licence, although there is a requirement that at least one well has been drilled to demonstrate the existence of the regulated resource. That one well may be in the contiguous extent of the discovered accumulation, rather than in each and every retention or production licence.54

PGE is also less prescriptive than PGERA on the timing of applying for a production licence. There is no time limit, except that the permittee will need to obtain a production licence before its exploration licence expires. This needs to be read subject to the Minister’s power to direct application for a production licence. Under PGE sub-s 36(1) the Minister may, after consultation, give a notice to the holder of an exploration licence or retention licence saying that the Minister is of the opinion that production of a regulated resource is currently commercially feasible and that the permit holder should apply for a production licence for the relevant area within the time stipulated. If the permit holder does not then apply within the time limit, the holder loses its rights to the area and the Minister can call for tenders for the grant of a production licence.

In the West Australian structure, a permittee starting with a large enough base may be able to obtain a production licence area of five blocks, or about 400 square kilometres. But getting more than one licence will depend on either having more than one exploration permit or being able to establish more than one location.55 In contrast, in South Australia one production licence may only be for 100 square kilometres, but multiple licences can be obtained to cover the area of the resource.

The drafter of the Guidance Notes to the AIPN UROA might give a rather harsher assessment of these processes. Regarding production areas, the Notes comment that defining those areas based on accumulation does not work. They point to the problem that the resource area can be so large that there may be many production sub-areas. There is a need to define those on some other basis, such as the area drained by multiple horizontal wells drilled and fractured from a single well pad, or a grid of 3 square kilometres.56 The timing of assessment is also relevant, and is discussed in the next section in relation to appraisal.

53 See South Australia, House of Assembly, (Hansard), 17 November 1999, for the second reading speech and being able to take into account probable reserves.
54 PGE ss 30(1)(a) and 31. See also PANT s 37.
55 There are examples of more than one location being established. This arose in the context of WA-1-P and WA-28-P.
56 See page 4 of the Guidance Notes.
The other states and the Northern Territory are closer to PGE than PGERA in their approach. None of New South Wales, Northern Territory, Queensland or Victoria provide for the declaration of a location or a specific time limit within which a production licence or retention lease must be applied for, other than the expiry of the exploration permit. There is an express or implicit requirement, expressed in different ways, that the permittee has discovered petroleum or petroleum in the area applied for.57 This or related provisions can limit the area to be exploited, although they do not all address the question of the delimitation of the extent of the resource with any clarity. So PANT sub-s 47(3) says that the Minister can only grant a licence for “the minimum number of blocks which, in his or her opinion, is reasonably necessary for the applicant to fully exploit the commercially exploitable accumulation of petroleum which occurs in the application area”. Under PGPSA sub-s 121(1)(b)(i), the area of the proposed petroleum lease must be “appropriate for the authorised activities proposed to be carried out”. What seems to be a broad discretionary provision in PGPSA is apparently to be based on the classification of resources and reserves.58 PAVic s 47, in contrast, is clear in its terms that a licence can be applied for in respect of “any part of the permit or lease area on which the holder has discovered petroleum or a reservoir”. In New South Wales there does not appear to be an equivalent provision, although the size of a production lease is limited by POA s 44 to not more than four blocks, which suggests the Minister has the discretion to make it less.

The possible application of discretion in this situation is interesting. PGE and PGERA both have a threshold test for obtaining a production licence, which turns on the presence of an accumulation of petroleum in the proposed licence area.59 In PGERA, the licence area is determined initially by an objective test of the blocks in the permit area to which the pool extends. The area is then sized according to the sliding scale. There is also a possible implication in PGERA, because of the pool idea, that the petroleum not only exists but is in one continuous area.60 Under PGE, the area of the petroleum licence is qualified by what is “a reasonable estimate at the time of granting the licence” of the area to which the discovery is “more likely than not to extend”. So the tests depend on an assessment of what is a reasonable estimate and what is more likely than not. These tests leave little room for an arbitrary exercise of discretion in relation to the production licence area. They therefore seem preferable to tests that depend on the regulator’s view of broader questions of what is “reasonably necessary”61 or “appropriate”.62 The language of PAVic is also clear, as a licence can be obtained for any part “on which the holder has discovered petroleum or a reservoir”. The Minister’s discretion under PAVic s 58 is favourable to the holder as he or she must ensure that the production licence area is the minimum area necessary to cover the maximum extent of the relevant petroleum field or reservoir.

57 Compare PGPSA ss 90(1) and 121(1)(b)(ii) with PAVic s 47.
58 The Explanatory Notes for the Bill leading to the PGPSA say in relation to this section: “If the purpose of the lease is petroleum production, the proposed area must contain identified resources and reserves of petroleum. It is expected that these have been determined in accordance with relevant industry accepted codes. It is intended that the level of knowledge, or classification of resources and reserves required, will be defined in departmental policy.” See https://www.legislation.qld.gov.au/Bills/SPDF/2004/PetGasProS1b04Exp.pdf. See also PGPSA ss 90 and 231 in relation to commercial viability reports.
59 PGE ss 21(3) and 35 (1)(a) and PGERA ss 46(1), 47(1) and 47(4).
60 The same problem would arise if PGERA used the word “accumulation” instead of “pool” because of the way sub-s 46(1) is worded. Contrast PGE sub-s 21(3).
61 PANT sub-s 47(3).
62 PGPSA sub-s 121(1)(b)(ii). But see PGE ss 21(3) and 35 (1)(a) and PGERA ss 46(1), 47(1), 47(4) and 231 concerning commercial viability reports.
Each of New South Wales, Northern Territory, Queensland and Victoria has the ability to require the holder of an exploration permit to apply for a production licence. 63 Except in New South Wales, these provisions have a commerciality test, or, in the case of Victoria, require that petroleum has been extracted. 64 That may also be a condition of the holder of an exploration permit being able to apply for a production licence. 65 However, leaving aside South Australia and Western Australia, none of the other states or the Northern Territory appears to contemplate the grant of multiple production licences over an exploration permit area. Also the area of a production licence is subject to limitations that vary across the states and the Northern Territory. 66

Another factor is the rate at which ground the subject of an exploration permit must be dropped off. While an initial term of five or six years is common among the states and Northern Territory, the number of possible renewals is not consistent and nor is the rate of relinquishment. In South Australia, for example, an exploration licence has a term of five years and may be renewable for one or two further terms, as specified at the time of grant. 67 In principle, but subject to the Minister’s discretion under PGE sub-s 26(4), 68 50% of the original licence area would be excised if there was one renewal, and 33.3% on each renewal if two renewals.

The basis of this article is that licensing of exploration and production of petroleum from shale and other tight rocks needs greater flexibility at critical points than conventional petroleum. What drives the difference is, first, geology but, secondly, a different style and life cycle of operation involving more wells and sustained exploration, drilling, testing, bringing wells on stream and decommissioning them. In some cases it may be reasonable for an explorer to seek a larger production area than would be required for a production licence for conventional petroleum plays. For the licensing authority, it is suggested that the balance will be between giving the explorer a reasonable commercial opportunity and not tying up too large an area. The licensing authority will want to maintain competition in bidding for exploration permits and also in releasing ground for new bids if development is not sufficiently rapid. Inevitably this will require some discretion in the licensing authority as to the delimitation of the extent of the resource. The main touch point for that discretion in PGE is the area covered by a discovery, where it is suggested that a practical and sensible approach is taken. The legislation in Victoria also takes a practical approach. It is submitted that the legislation of the other states and the Northern Territory is much less clear. The reason for this lies in the fact that, generally speaking, they were designed for conventional petroleum plays.

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63 POA s 37, PANT s 30, PGPSA s 96 and PAVic s 35.
64 PANT s 30 requires the Minister to be satisfied that a commercially exploitable accumulation of petroleum may occur in the permit area. PGPSA s 95 requires the Minister to reasonably consider that the holder of an authority should apply for a production lease because petroleum production in the area is currently commercially viable or is likely to become commercially viable within two years. PAVic s 35 requires the holder of the permit to have extracted petroleum as a result of a discovery.
65 PANT s 29(3) requires a permittee to have discovered a commercially exploitable accumulation of petroleum. PGPSA ss 121(1)(b)(ii) and (g) require the proposed area to contain commercial quantities of petroleum and for commerciality to be established. PAVic s 47 allows the holder of a permit to apply for a production licence in respect of any part of the permit or lease area on which the holder has discovered petroleum or a reservoir.
66 In New South Wales, four blocks (POA s 44); in the Northern Territory, 12 blocks (PANT s 46(1). PGPSA subss 121(1)(b)(ii) provides for an area “appropriate for the authorised activities proposed to be carried out”. PAVic s 58(1) requires the Minister to ensure that it is the minimum area necessary “to cover the maximum extent of the relevant petroleum field or reservoir”.
67 PGE s26.
68 See also PANT s24A.
One way forward, which could work for most of the legislation, would be to amend the retention lease provisions to make clear allowance for feasibility testing and production to test commerciality. This would be logical as it would be part of proving up the commerciality of the resource. Those provisions could also make allowance for delineating the extent of the resource at this later time, based on the information then available and using objective tests about the presence of petroleum. It would be necessary to review the royalty arrangements to ensure that if production were ongoing, it would attract a royalty.

**Licences: appraisal and feasibility testing**

While it is usual in conventional petroleum projects to produce a certain amount of petroleum on an appraisal basis from a well, the development of unconventional petroleum plays requires a proof of concept, usually involving several wells.\(^69\) If what is produced is mainly gas, then access to infrastructure such as pipelines or a gas plant becomes a major consideration, as otherwise gas would have to be flared. Petroleum companies may want to test commercial feasibility under an exploration licence or retention lease rather than convert to a production licence prematurely. It is interesting to compare how the petroleum legislation of the states and Northern Territory deals with this. The question here is whether the legislation allows sufficient flexibility for the petroleum company to work through its proof of concept and run any necessary pilot operations to test production, before it applies for a production licence. With the possible exception of South Australia and Queensland, this is not clear.

PGERA sub-s 38(1) provides that a petroleum exploration permit authorises the permittee to explore for petroleum and to carry on such operations and execute such works as are necessary for that purpose. What constitutes operations is not defined. Section 48C, which sets out the powers conferred by a retention lease, is in similar terms, and therefore no more extensive. The view of the Department of Mines and Petroleum of Western Australia is that taking petroleum on an appraisal basis is permitted, and this seems to be as a result of departmental practice. It can also be implied from s 38, which allows the conduct of such operations “as are necessary” for the exploration of petroleum. The word “appraisal” is not used in PGERA and there is no reference to testing production or production techniques in the context of exploration permits or retention leases.\(^70\) As exploration is not defined, it is possible to take a broad view of what it comprises, and argue that it extends to appraisal. However, there must be some doubt that it would extend to production designed to test the commercial feasibility of a project. Also, some caution is required, as the recovery of petroleum, except in accordance with a production licence, is an offence, unless it is otherwise permitted by the Act.\(^71\) Accordingly, an intriguing question then is where that permission might be found.

The South Australian legislation contains an example, as well as some useful extensions which allow more than exploration under an exploration licence. PGE sub-s 21(2) provides that an exploration licence authorises exploratory operations and in particular operations to establish the nature and extent of a discovery and to establish the feasibility of production and appropriate production techniques. Section 27(1)(1) authorises the production of petroleum from a well for the purpose of establishing the nature and extent of a discovery, although this is limited to 10 days

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\(^{69}\) This is described in *Shale and Tight Gas in Western Australia A Whole-of-Government Approach* (2015 Edition) on page 19: “The proof of concept stage involves drilling multiple wells to determine the physical extent, reserves and likely production rate of a field, and provides the information to design a fracture stimulation program if required”. For reference, see [http://www.aipn.org](http://www.aipn.org); see the Guidance Notes, 3.

\(^{70}\) Royalty is payable if petroleum is recovered under a petroleum exploration permit. See PGERA sub-s 142(2).

\(^{71}\) PGERA s 49.
without Ministerial approval. It appears to be departmental policy that the Minister will give approval to extend this period for an appropriate term to demonstrate commerciality. Approval could be subject to a condition that a royalty was payable. So the approval letter from the Minister supplies the requisite permission. As a matter of policy, this would also be permitted under a petroleum retention licence. In both cases it would assist development planning as a prelude to applying for a petroleum production licence.

Queensland also has provisions allowing production testing under an Authority to Prospect (ATP) or petroleum lease. Queensland has possibly the most helpful extensions of exploration. PGPSA s 32 authorises the holder of an ATP to explore for petroleum, test for petroleum production and evaluate the feasibility of petroleum production. Section 72 authorises for an ATP “testing (production testing) for petroleum production from each petroleum well in the area of the authority”. This is limited to 30 days, which can be extended by the Minister and that approval can be subject to conditions.\(^{72}\) The underlying policy here is that any production of gaseous petroleum, other than that produced as an unavoidable result of production on an ATP, may only be carried out on a production licence. The idea is that production testing is carried out on an ATP to establish if an area within the ATP contains commercial quantities of petroleum, which is a requirement of an application for a production licence.

PGPSA s 33 authorises incidental activities, if reasonably necessary for one of the matters listed in s 32. The examples given include constructing or operating plant or works including, for example, communication systems, pipelines associated with petroleum testing, powerlines, roads, separation plants, evaporation or storage ponds, tanks and water pipelines. PGPSA is subject to amendments in the Mineral and Energy Resources (Common Provisions) Act 2014 (Qld) to make it clear that production of gaseous petroleum is only an incidental activity if it is “the unavoidable result of ATP production testing”. PGPSA s 72 contains a hierarchy of uses for gaseous petroleum released during production testing, which can allow flaring if it is not commercially or technically feasible to use it commercially. If processing of the gas is needed, a petroleum facility licence would be required. The 2014 legislation is part of Queensland’s program to modernise its resources regime. It creates a common provisions act into which harmonised legislation from Queensland’s five resources acts will be transferred. The royalty provisions in the PGPSA also cover production testing and appear to cover production under an ATP.\(^{73}\)

In New South Wales, POA s 29 gives the holder of an exploration licence the exclusive right to prospect for petroleum on the land comprised in the licence, “prospect” is defined in s 3 to mean carry out works on, or to remove samples from, land for the purposes of testing the quality and quantity of petroleum in the land and the potential to recover petroleum from the land. PANT subs 29(1) gives the permittee the right to explore for petroleum, and to carry on such operations and execute such works as are necessary for that purpose. Section 29(2) does not set out any significant extensions of use to a permittee wanting to test several wells, except perhaps the approval in sub s 29(2)(c) to carry out the technical works program.

The onshore petroleum legislation of the states and Northern Territory does not recognise a proof of concept stage for petroleum operations. Queensland and South Australia have the widest extensions to exploration which permit both the proof of concept and also initial production operations. Given the sparse drafting of the PGE and PGPSA in these areas, and the short initial periods allowed for production testing, a policy guideline could add helpful clarity.

\(^{72}\) PGPSA s 72.

\(^{73}\) See PGPSA ss 590 and 591A.
Conclusion

The petroleum legislation of the states and Northern Territory is not drafted to treat petroleum derived from shale or other tight rocks differently from petroleum derived from a conventional petroleum reservoir, despite the differences in a number of important areas. These include the size and duration of permit areas, transitioning from an exploration permit to a production licence or conducting appraisal. Because operations for petroleum from shale and tight rocks are still relatively undeveloped in Australia, most of the problems for explorers will be in securing appropriately sized exploration areas and being able to delineate the resource to transition to a production licence. In this respect, the legislation in South Australia offers a practical way to delineate the resource.

The legislation does not define “appraisal” in the context of unconventional petroleum (or proof of concept) or generally provide a clear way, short of applying for a production licence to conduct a pilot plant and sell petroleum to test the feasibility of a shale or tight-rocks project. South Australia and Queensland are exceptions in that PGE and PGPSA contain provisions allowing feasibility testing.

If operations in relation to shale and tight rocks are on a single-well basis close to existing infrastructure, this may not seem particularly problematic. However, this situation is not ideal. If the intensity of those operations grows, the lack of differentiation will become more serious. In particular, the lack of recognition of the importance of proof of concept and pilot projects for unconventional petroleum developments will cause barriers to the development of petroleum from shale and tight rocks.