Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**




Guidelines to Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015 and Petroleum (Submerged Lands) (Resource Management and Administration) Regulations 2015

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** A reference to the Minister means the Minister for Mines and Petroleum, or the Executive Director, Resource and Environmental Compliance*

1 Background to the Resource Management and Administration Regulations (RMAR) 2015 and the guidelines

1.1 Legal framework of the regulations

The legal framework for the administration of exploration and recovery of petroleum, in the Western Australian onshore and State waters areas, is provided within the *Petroleum and Geothermal Energy Resources Act 1967* [PGERA67] and the *Petroleum (Submerged Lands) Act 1982* [PSLA82]. Part IV of each Act provides that: 'The Governor **may make regulations**, not inconsistent with this Act, prescribing all matters that by this Act are required or permitted to be prescribed or are necessary or convenient to be prescribed for carrying out or giving effect to this Act.'

Accordingly, the Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015 [PGER RMAR 2015] were promulgated and came into force on 1 July 2015. These Regulations replaced the contents of the 'Schedule of Onshore Petroleum Exploration and Production Requirements 1991 (Amended 21 May 2010)' and the 'Schedule of Geothermal Exploration and Production Requirements 2009'.

Similarly, the Petroleum (Submerged Lands) (Resource Management and Administration) Regulations 2015 [PSL RMAR 2015] also came into force on 1 July 2015 and replaced the contents of the 'Schedule – Specific Requirements as to Petroleum Exploration and Production Western Australian Coastal Waters 2007'. Also, the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2006 were repealed on the commencement of the PSL RMAR 2015.

The Resource Management and Administration Regulations 2015 are the third and final part of the suite of regulations that commenced in 2010 with the introduction of the 'Petroleum and Geothermal Energy Resources (Occupational Safety and Health) Regulations 2010' and the 'Petroleum and Geothermal Energy Resources (Management of Safety) Regulations 2010'. The process continued in 2012 with the commencement of the 'Petroleum and Geothermal Energy Resources (Environment) Regulations 2012'. Collectively these three sets of regulations determine the management and administration of activities related to the exploration for, and the recovery of, below-ground energy resources in Western Australia.

This guideline document covers both sets of resource management and administration regulations, namely the PGER RMAR 2015 and PSL RMAR 2015. In the interests of simplicity these generally have been abbreviated to 'RMAR 2015' within the guidelines, except where some distinction is needed. There are a few differences between the two sets of regulations, however, these are minor and effectively allow both sets of regulations to be treated within these guidelines under a single banner. The differences resulted from the need to address geothermal energy resources within the PGER RMAR 2015. This has had the effect of creating one additional regulation ([r. 63], in Part 7) and the inclusion of another schedule (Schedule 4 – Geothermal energy recovery development plan) in the PGER RMAR 2015.

No reference to geothermal energy resources is made in the PSL RMAR 2015.

Within these guidelines, and in the RMAR 2015, use of the word *'petroleum'* should be read as also including '*geothermal energy'* unless mentioned specifically.

1.2 Purpose

The RMAR 2015 requires the provision of information on petroleum activities to assist in ensuring that the Minister is sufficiently informed about all significant aspects of exploration, discovery, development and production or injection operations in relation to petroleum and geothermal energy resources. This information will provide consistent, effective and transparent regulation of the State's petroleum and geothermal energy resources.

The RMAR 2015 cover a range of resource management and administration matters. There is no distinction made in the RMAR 2015 between conventional and unconventional (shale and tight gas) reservoirs. These matters include:

- surveys
- management of well activities (well management plans – WMPs)
- field management plans (FMPs) and geothermal energy resources development plans (GERDPs)
- discovery assessment reports
- annual assessment reports
- data management
- submission of information
- release of technical information.

The guidelines provide industry information to assist its compliance with the regulations.

The guidelines document is a 'living document' and can be updated as necessary based on constructive feedback, to DMIRS, from stakeholders.

1.2.1 The delegation of administration to the Department of Mines and Petroleum by the Minister

The Department of Mines, Industry Regulation and Petroleum Safety (DMIRS), administers the Acts and the RMAR 2015 on behalf of the Minister for Mines and Petroleum (the Minister), as the Minister's delegate. All provisions in the RMAR 2015 have been delegated by the Minister to the position of Executive Director, Petroleum Resource and Environmental Compliance Division within DMIRS.

All applications and correspondence in relation to RMAR 2015 are required to be directed to the Executive Director, Resource and Environmental Compliance Division.

DMIRS has the regulatory responsibility to ensure compliance with legislation, regulations and sound resource management practices, and that petroleum operations in Western Australia are conducted in a manner that adequately safeguards occupational safety and health objectives and protects the environment.

1.2.2 Intended audience

The RMAR 2015 apply to all petroleum and geothermal energy instruments (i.e. titles, special prospecting authorities, access authorities, and instruments of consent (scientific instruments) under section 116 of the PGERA67 and section 123 of the PSLA82). Therefore, petroleum and geothermal exploration and production 'registered holders' of the instruments are considered to be the primary audience for, and are anticipated to be the main users of these guidelines. Within the regulations, the term 'title holder' is commonly used to denote registered holders, which is the term legislated in the petroleum Acts.

The potential for other readers, including the general public, to use these guidelines is acknowledged. However, the document does require the reader to have a general understanding of the geotechnical and engineering nomenclature commonly used within the petroleum and geothermal industries.

A glossary of selected terms commonly used in the RMAR 2015 and the Acts and throughout the guidelines can be found in Appendix 5 and a list of acronyms are provided in Appendix 6 of the guidelines document.

The current version of these guidelines is accessible from the DMIRS website at www.dmirs.wa.gov.au

Stakeholders to these guidelines are encouraged to provide feedback on the guidelines to DMIRS by emailing petroleum.reports@dmirs.wa.gov.au

2 The philosophy of the RMAR 2015 and guidelines

The RMAR 2015 is an objective-based set of regulations within a framework of managing risk for the exploration for, and recovery of, petroleum and geothermal energy resources within onshore and coastal water areas of Western Australia. There is, however, still some necessary prescription in the regulations, particularly with data submission and reporting.

The new regulatory regime determines that the responsibility for achieving objectives and managing risk in conducting petroleum activities, through the use of industry 'best practice', lies with the holder(s) of the petroleum title.

2.1 The aims of objective-based regulations

Recent years have seen a general trend towards the application of objective-based regulation. Regulators have moved away from prescribing specific procedures, such as those provided for in the 'Schedule of Onshore Petroleum Exploration and Production Requirements – 1991 (Amended 21 May 2010)' and 'Schedule of Geothermal Exploration and Production Requirements 2009'. The emphasis today is on the achievement of the objectives of the legislation. Industry is required to use appropriate standards to demonstrate to DMIRS how objectives are to be achieved within an acceptable risk profile.

There have been two main drivers for having an objective-based regulatory regime:

1. In industries that are subject to rapid technological change, prescriptive regulations are likely to become outdated quickly and, consequently, become counterproductive in their intended role to improve safety and achieve greater efficiencies.
2. Particularly in the area of occupational safety and health (OSH), there has been acceptance that where governments attempt to specify (through prescriptive legislation) appropriate measures to minimise risk, the government effectively assumes the role of risk management and minimisation. Australian governments see the responsibility for risk management and minimisation to be the responsibility of the title holder carrying out the petroleum activity.

2.2 The provision of selective prescriptive regulations

The RMAR 2015 cover the full life cycle (history) of a well, from its planning and initial drilling ('spud') to decommissioning, and of a field, from initial planning and field development to field decommissioning.

There are circumstances where prescriptive requirements, or rules, are necessary, as they provide title holders with a clearer understanding of what they are required to do, therefore simplifying and standardising administrative processes.

Issues that require some degree of prescriptive regulation include the content and layout requirements for various approval applications, reports and data. These are intended to provide a 'checklist' which covers topics that title holders should consider in the provision of information for a submission. It also serves to avoid the inclusion of material that is superfluous to the needs of the Regulator. It is intended that WMPs, FMPs and GERDPs be fit for purpose rather than be all encompassing documents and can be revised as needed.

2.2.1 The concept of 'good oilfield practice'

Good oilfield practice, as a concept, is defined in Section 5 of the PGERA67 (and elsewhere in industry literature) as meaning *"all those things that are generally approved as good and safe in the carrying on of exploration for petroleum, or in the operations for the recovery of petroleum, as the case may be."* The premise is that if activities are carried out in accordance with good oilfield practice, good and safe operations will result and serious adverse events will be avoided. The concept has industry acceptance worldwide. Good oilfield practice is not static and can, and will, change as new technology is embraced and new methods for undertaking petroleum activities are developed. Good oilfield practice contains the underlying concepts of conservation, energy efficiency, and maximum ultimate recovery.

2.3 Risk assessment and risk management

Risk management is an important component of resource management and oilfield operations. This section provides general guidance on practices acceptable to DMIRS, and used internationally, within the petroleum resource industry, in the assessment and management of risk. Title holders should be able to demonstrate in their submissions an understanding of risks, their causes, their impacts and how they are to be managed/mitigated.

The practices described below are generic to most petroleum activities, be it resource management, exploration (including surveys) or production operations. Most organisations have adopted a risk assessment and management process, based on the international standards, as outlined in the following sections.

2.3.1 The framework guidance for risk management

Risk management generally refers to the processes by which risks are identified and managed effectively. The International Organization for Standardization (ISO), standard for risk management *ISO 31000:2009* provides principles and guidelines on the implementation of risk management. This standard has been adopted in Australia and New Zealand as *AS/NZS ISO 31000:2009*. The ISO standard or its Australian equivalent *(AS/NZS ISO 31000:2009)* is accepted by the petroleum industry internationally.

2.3.1.1 Risk assessment and risk management defined

In *AS/NZS ISO 31000:2009*, risk is defined as the "effect of uncertainty on objectives". An effect may be positive, negative, or a deviation from the expected; an objective may be financial, related to health and safety, or defined in other terms. Uncertainty is the state of deficiency, even partial, of information related to an understanding or the knowledge of an event, its consequences, or likelihood.

The relationship between the risk management principles, framework, and process is shown in Figure 1. There are 11 principles that need to be complied with by an organisation, for risk management to be effective, as shown in the left hand column of Figure 1, items a) to k), clause 3. These are:

(a) creates value
(b) integral part of organisational processes
(c) part of decision making
(d) explicitly addresses uncertainty
(e) systematic, structured and timely
(f) based on the best available information
(g) tailored
(h) takes human and cultural factors into account
(i) transparent and inclusive
(j) dynamic, iterative and responsive to change
(k) facilitates continual improvement and enhancement of the organization.

The success of risk management depends on the effectiveness of the risk management framework, as described by clause 4 shown in the middle column of Figure 1. It addresses five elements necessary for an effective risk management framework.

- Mandate and commitment – a strong and sustained commitment to risk management.
- Design of framework for managing risk – a systematic approach to designing a risk management framework.
- Implementing risk management – a risk management plan is developed and implemented.
- Monitor and review the framework – continually ensure the effectiveness of the framework.
- Continual improvement of the framework – based on results of monitoring and review, assess how the framework can be improved.

The risk management process comprises of five key elements (clause 5 – right hand column of Figure 1):

1) *Communication and consultation* – throughout the risk management process, various forms of communications (written or verbal) between risk manager, risk owner, and stakeholders need to occur to ensure all stakeholders understand the basis on which decisions are made.

2) *Establishing the context* – setting boundaries or parameters about risk appetite and risk management activities, considering internal factors (strategy, resources and capabilities), and external factors (social, cultural, political and economic) that will influence the risk management process.

3) *Risk assessment* – identifying, analysing and evaluating risks. It is the what, where, when, why and how risks could arise, and their effect on achieving an organisation's objective in the management process. It determines the cause of a risk, and the consequences, likelihood and risk level. It also looks at the effectiveness of existing controls.

4) *Risk treatment* – when the level of risk is unacceptable, there is a need to access and select one or more options to reduce the level of risk to an acceptable level for the organisation. Such options could be avoiding the risk, treating the risk sources, modifying likelihood, changing consequences, or sharing elements of risks.

5) *Monitoring and review* – planned, regular monitoring of risks and the risk management framework and process is necessary to ensure the effectiveness of the risk control/treatment and so that emerging risks are identified.

2.3.1.2 Strategies for enhanced risk management

The Annex of the *AS/NZS ISO 31000:2009* lists five attributes for enhanced risk management:

1) Continual improvement.
2) Full accountability of risks.
3) Application of risk management in all decision-making.
4) Continual communications.
5) Full integration in the organisations' governance structure.

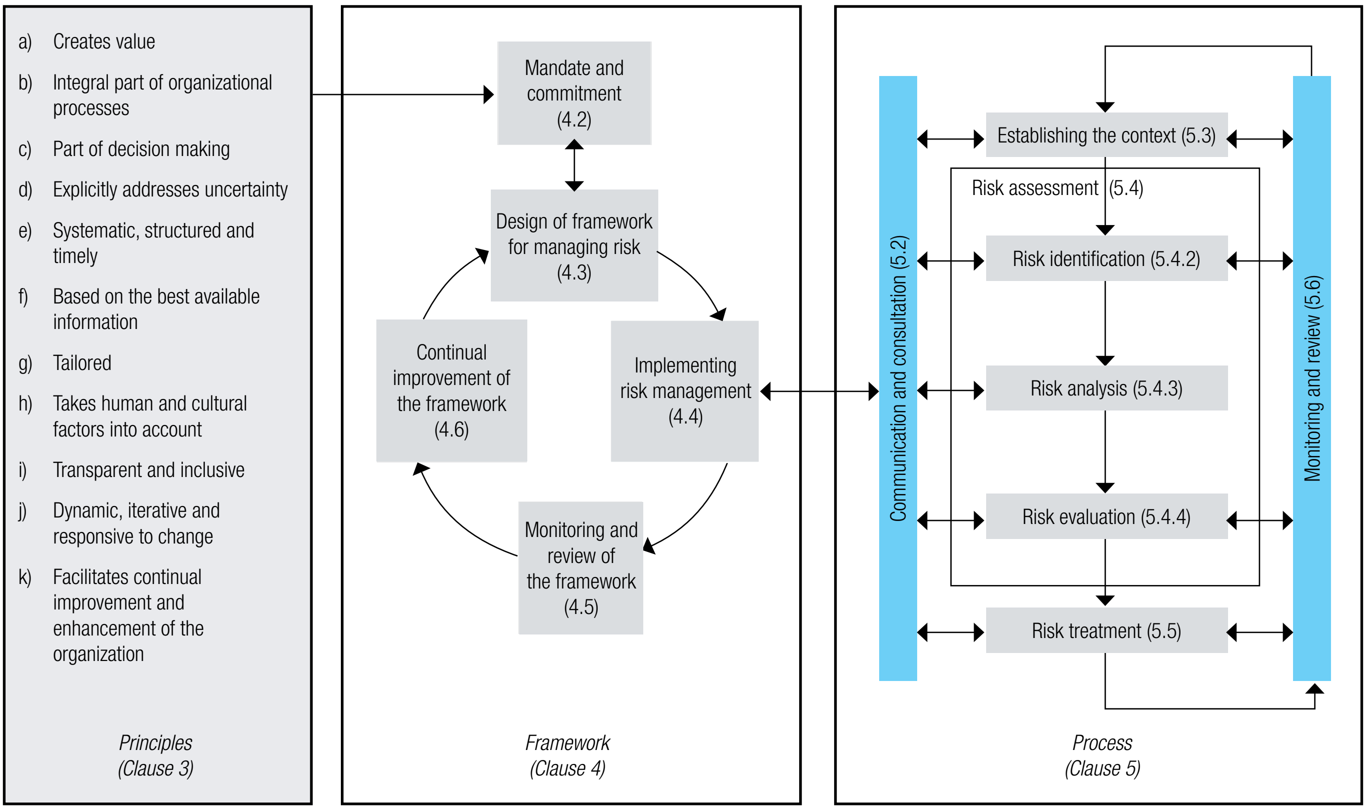

Figure 1 Relationship between the risk management framework, principles and process (source: *AS/NZS ISO 31000:2009*)

2.3.1.3 Risk classification

Risk classification is the grouping of different risks according to their consequences and likelihood of occurrence. Risk rating is often expressed in terms of an assessment of the combination of the consequences of an event, including changes in circumstances, and associated likelihood of its occurrence.

Table 1 provides examples of impacts associated with different levels of consequence on human health, environment and budget. Table 2 defines the qualitative measures of likelihood, that is, the frequency of occurrence of an event.

Risk classification should be as per the title holder's risk assessment of consequence versus likelihood. Figure 2 is a typical 5x5 risk matrix for identifying risk classification (risk level or risk rating) of a given event based on consequence and likelihood.

Table 1. Generic consequence classification and examples of impacts to the consequence categories of injury, environment and financial loss

Descriptor	Examples for injury; environment; financial loss
Insignificant	No lost time injury; low impact; below $100,000
Minor	Maximum 5 days lost time injury; contained low impact; between $100,000 to $1 million
Moderate	Maximum 10 days lost time injury; uncontained impact, able to be rectified in less than 1 year; between $1 – $5 million
Major	Single fatality; extensive hazardous impact requiring between 1 and 5 years rehabilitation; between $5 – $20 million
Catastrophic	Multiple losses of life or permanent disability; uncontained hazardous impact with residual effect and greater than 5 years rehabilitation; above $20 million

Table 2. Qualitative measures of likelihood

Descriptor	Frequency	Definition
Almost certain	More than once per year	The event will occur in most circumstances as there is a history of continuous occurrence with past projects/activities
Likely	At least once per year	The event is expected to occur as there is a history of frequent occurrence with past projects/activities
Possible	At least once in 3 years	The event should occur at some time as there is a history of casual occurrence of similar issues with past projects/activities
Unlikely	At least once in 10 years	Not expected, but it may occur at some time
Rare	Less than once in 15 years	Highly unlikely, but it may occur in exceptional circumstances

Likelihood	**Almost certain**	Medium	High	High	Extreme	Extreme
	Likely	Low	Medium	High	Extreme	Extreme
	Possible	Low	Medium	Medium	High	High
	Unlikely	Low	Low	Medium	Medium	High
	Rare	Low	Low	Low	Low	Medium
		Insignificant	**Minor**	**Moderate**	**Major**	**Catastrophic**
		Consequence				

Figure 2. Risk classification matrix – likelihood versus consequence

Risk treatment key:

- Low – Monitor and manage
- Medium – Monitor and maintain strict measures
- High – Review and introduce additional controls to lower the level of risk
- Extreme – Do not proceed – Immediately introduce further control measures to lower the risk. Reassess before proceeding

2.3.2 The concept of 'as low as reasonably practicable' (ALARP)

An outcome from the RMAR 2015 objective-based regulatory regime is the assignment, to the title holder of a permit or instrument, of the responsibility for the evaluation and management of risk to a level that is 'as low as reasonably practicable' (ALARP). The ALARP principle is widely understood and accepted within the petroleum industry internationally.

The principle recognises that ALARP defines the point where the investment costs required to further reduce the risks of an activity become disproportionate to the benefit gained, and may not be practically feasible or economically viable. It should be remembered that there might be circumstances where a risk is still unacceptable even after being reduced to ALARP, and therefore the activity should not proceed.

Risk assessment decisions for petroleum activities are mostly focused on health, safety and the environment and optimal resource recovery. The title holder has full responsibility for managing risk; for risk analysis and evaluation; and implementing all risk reduction measures. It is very important that the effectiveness of these measures is monitored and any deficiencies corrected in the risk treatment and control measures.

The application of the ALARP principle to petroleum activities allows the title holder to adopt those practices and technologies that are best suited to individual circumstances, activities and locations. Petroleum activity practices and technologies are not prescribed within the RMAR 2015, however a title holder is expected to demonstrate through their risk management plan that the risk profile for a proposed new or novel petroleum activity is ALARP.

3 The Parts and Schedules of the RMAR 2015

The RMAR 2015 are assembled into a document having a total of ten (10) main 'Parts', each of which pertains to a specific area or topic covering the primary aspects of resource management. The Parts may be further arranged into subgroups under a number of Divisions and Subdivisions, which contain their respective regulations. These regulations are consecutively numbered and are cross-referenced as 'r. 1';' r. 2'; 'r. 3' etc.

The following discussions clarify specific areas of the RMAR 2015, as outlined in their respective Parts, Divisions and Schedules. Each regulation is numbered in the Parts, from r. 1 in Part 1, through to r. 102 in Part 10, in the PGER RMAR, and r. 101 in the PSL RMAR in Part 10.

Between the PSL and PGER RMAR from Part 8 onwards, regulation numbers differ by one, due to the inclusion of a geothermal energy recovery development plan in r. 63 in the PGER regulations only.

For simplicity, the PGER RMAR numbers are referenced within these guidelines. If there is a need to look at the PSL regulations, please note that post r. 63 each regulation will be different by one number when compared to the same regulation in the PGER RMAR.

It is important to note that the intent of the guidelines is to facilitate understanding and use of the regulations, and the preparation and submission of reports and applications.

Only material that is significant to the subject of a report or application should be provided to DMIRS. Prescriptive regulations are provided where a 'checklist' approach limits input to the essential or relevant material. The guidelines will continue to be adapted as future experience improves the understanding and use of these regulations by all stakeholders.

3.1 Structure of the RMAR 2015 document

The RMAR 2015 cover a range of resource management and administration matters. The Regulations within the Parts are followed by the Schedules, which provide more specific details relating to information and reporting requirements of the respective regulations. For example *'Schedule 1 – Well management plan'* has the cross reference to regulation [r. 17(1)] which appears in Part 3, Division 1 of the RMAR 2015. The cross-references are shown in square brackets in the header section of each Schedule.

Table 3 of these guidelines summarises the contents of the Parts, and provides cross references to their respective Regulations and the Schedules that append the RMAR 2015.

Following the 10 Parts of the RMAR 2015 are 17 Schedules that are 'object clauses' as shown in Table 4. These 17 Schedules provide further expansions pertaining to a number of the regulations. (Not all Parts have Schedules attached to them. Some Parts have multiple Schedules; Part 8 has 13 Schedules. Page numbers in column 3 of Table 4 reference the RMAR 2015 document pagination.)

Table 3. PGER RMAR 2015: Parts, Regulations and Schedules

Part No.	Part Title	Page No.	Regulations	Schedules
Part 1	Preliminary	1	r. 1 – r. 4	
Part 2	Surveys	6	r. 5 – r. 9	
Part 3	Management of well activities Division 1 – Well management plan (5 subdivisions) Division 2 – Control of hazards and risks	10 10 22	r. 10 – r. 33	1
Part 4	Discovery assessment reports	23	r. 34 – r. 36	
Part 5	Annual assessment reports	26	r. 37 – r. 39	2
Part 6	Field management plans for petroleum recovery Division 1 – Preliminary Division 2 – Field management plan requirements Division 3 – Obtaining approval of field management plan Division 4 – Revision of approved field management plan Division 5 – Recovery of petroleum before field management plan approval	28 28 28 29 31 36	r. 40 – r. 61	3

Table 3. PGER RMAR 2015: Parts, Regulations and Schedules (continued)

Part No.	Part Title	Page No.	Regulations	Schedules
Part 7	Other matters relating to petroleum or geothermal energy recovery	38	r. 62 – r. 63	4
Part 8	Data management Division I – Preliminary Division 2 – Requirement for keeping information Division 3 – Requirement for collection and retention of cores, cuttings and samples Division 4 – Requirement for giving reports and samples	40 40 40 41 43	r. 64 – r. 80	5 – 17
Part 9	Release of technical information about petroleum and geothermal energy resources Division 1 – Preliminary Division 2 – Classification of documentary information Division 3 – Release of documentary information Division 4 – Release of mining samples	54 54 58 64 70	r. 81 – r. 98	
Part 10	Transitional provisions	73	r. 99 – r. 102	

Table 4. PGER RMAR 2015 Schedules, respective Parts and Regulations

Schedule No.	Schedule title	Page No.	Part No.	Regulation
Schedule 1	Well management plan	75	Part 3	[r. 17(1)]
Schedule 2	Annual assessment report	79	Part 5	[r. 37(2)]
Schedule 3	Field management plan	83	Part 6	[r. 48(1)]
Schedule 4	Geothermal energy recovery development plan	86	Part 7	[r. 63]
Schedule 5	Daily well activity report	89	Part 8	[r. 72(1)]
Schedule 6	Final well activity data	91	Part 8	[r. 73(1)]
Schedule 7	Final well activity report	92	Part 8	[r. 73(1)]
Schedule 8	Well completion data	95	Part 8	[r. 74(1)]
Schedule 9	Well completion report	97	Part 8	[r. 74(1)]
Schedule 10	Weekly survey report	101	Part 8	[r. 75(1)]
Schedule 11	Survey acquisition data	102	Part 8	[r. 76(1)]
Schedule 12	Survey acquisition report	104	Part 8	[r. 76(1)]
Schedule 13	Processed survey data	106	Part 8	[r. 77(1)]
Schedule 14	Survey processing report	110	Part 8	[r. 77(1)]
Schedule 15	Interpretative survey data	111	Part 8	[r. 78(1)]
Schedule 16	Survey interpretation report	112	Part 8	[r. 78(1)]
Schedule 17	Monthly production report	113	Part 8	[r. 79(1)]

4 Guidelines to the regulations

4.1 RMAR Part 1 – Preliminary [r. 1 – r. 4]

Part 1 provides general information concerning commencement day, objects and terms used in the regulations. The correct citation for these regulations is given in r. 1 as the *Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015*. Within these guidelines reference to the regulations is abbreviated to RMAR 2015.

r. 2 states when the RMAR 2015 came into operation. It deals with important issues relating to the timing for the adoption, and effects, of the introduction of the RMAR 2015. The RMAR 2015 were published in the *Gazette* on 30 June 2015, allowing r. 1 and r. 2 to come into operation on that date. Part 9, to do with the release of technical information, came into operation on 1 July 2015 [r. 3]. The remainder of the regulations also came into operation on 1 July 2015. Following the gazettal of the RMAR 2015, a period of 12 months was allowed for compliance within the provisions of the transition regulations, which are detailed in Part 10 of the RMAR 2015.

Objects of regulation are described in r. 3. These objects relate to ensuring that petroleum exploration and recovery operations are conducted according to highest standards; ensuring the Minister is kept informed; providing a framework for the adequate collection of resources data; and to the efficient management of data confidentiality and disclosure.

Terms used in the RMAR 2015 are listed in r. 4. It should be noted that there are other terms defined throughout the regulations. A glossary of terms is in Appendix 5 and acronyms in Appendix 6.

4.2 RMAR Part 2 – Surveys [r. 5 – r. 9]

In the course of exploration for, appraisal or production of petroleum and/or geothermal energy resources, the instrument holder may perform various types of geotechnical data acquisition surveys. For example, the exploration geological rationale of a work program may utilise geochemical, geological or geophysical surveys. Similarly, an instrument holder of a Special Prospecting Authority (SPA) may use surveys in frontier or greenfield areas where little or no exploration has been previously undertaken.

Each data acquisition survey requires approval from DMIRS prior to the commencement of the survey. Surveys usually form part of the work commitments on titles; approval ensures the completed survey will fulfil the work commitment of the work program year. Penalties apply if surveys are performed without an authorising title and requisite approval from DMIRS [r. 5]. Seismic reprocessing does not need approval from DMIRS although instrument holders may wish to consult with DMIRS to ensure the reprocessing performed will fulfil the work commitment (see also Part 8 and 9 regarding submission and release of technical information).

Surveys performed in a well, such as wireline logging and well interventions with data acquisition, are covered under *'well activities'*. The approval procedures for this category of survey are the subject under Part 3 – Management of well activities (see heading 4.3). Stakeholder questionnaires or community surveys are not covered under the RMAR 2015.

The application process for survey approval is described in Part 2, r. 6 – r. 8 of the RMAR 2015, including the required information and timeframe for submission and approval of the applications. Much of the required information for the application listed in Part 2, r. 6(2)(b) is straightforward. The objective of the survey, and how results will impact exploration, appraisal, and/or production and the remainder of the work program, is particularly important. For SPA surveys, the anticipated outcomes should be described with respect to the petroleum or geothermal prospectivity of the area. Risks which may affect successful completion of the survey, or prevent quality analysis and interpretation of the data, should be addressed in the application.

If the survey type is new or not regularly performed in Western Australia, the instrument holder should provide references to scientific papers, industry appraisals, or case studies of the survey methodology and its effectiveness. The instrument holder must take into consideration r. 6(2)(b)(xi) and the requirements of r. 76(2)(b) in relation to the survey and provide the Minister with details of anything likely to prevent compliance at the time of application.

The map described in Part 2 r. 6(2)(c) should be legible, with clear legends, scale bars, and north indicator. Cadastral information such as nearby towns and major roads should be included, as well as relevant land tenure, such as Native Title Determined Areas and shire boundaries. The map should show nearby petroleum title boundaries and graticular blocks, as well as the estimated survey locations/lines and an indication of the order of acquisition. Where the proposed survey extends beyond the boundaries of the instrument holder's title, application for an Access Authority in accordance with the requirements of section 106 of the PGERA67 or section 112 of the PSLA82 must accompany the survey application. The Minister may request more information relating to a survey application [r. 8].

The timely lodgement of survey applications, depending on the location and land to be accessed, is provided under r. 7. Applications must be made at least 30 days before the proposed start date of surveys, although surveys that require entry into reserved land or marine reserves require considerably longer notice (90 days minimum) due to the provisions of section 15A of the PGERA67 or section 18A of the PSLA82. This entry requires consultation between responsible Ministers and the setting of any relevant conditions, and timing for this has to be taken into account.

As well as the RMAR requirements, surveys must also have an approved environment plan (EP) under the Petroleum and Geothermal Energy Resources (Environment) Regulations 2012 and an approved safety management system under the Petroleum and Geothermal Energy Resources (Management of Safety) Regulations 2010.

An instrument holder must undertake early stakeholder engagement with land owners and acquire consent in writing to access land in accordance with section 16 of the PGERA67. Sections 17 through 20 and 117 must also be considered and addressed as required. For further information see **www.dmirs.wa.gov.au/Land-access**

When a decision is made on the application, the instrument holder will receive written notification of the decision, including any conditions on the approval or reasons for a refusal [r. 9].

During and after completion of the survey, regular reporting on the progress and results are required. Data submission requirements are covered under Part 8, Division 4, Subdivision 2 – Reports about surveys, and Schedules 10 through 16 (see heading 4.8.4.2 in this document). Reports should be sent to **petroleum.reports@dmirs.wa.gov.au** and raw data submissions to the Statutory Exploration Information Group (SEIG) at **petdata@dmirs.wa.gov.au** for input into the Western Australian Petroleum Information Management System (WAPIMS).

Survey applications can be submitted online via the DMIRS website at **www.dmirs.wa.gov.au/PGR**

4.3 RMAR Part 3 – Management of well activities [r. 10 – r. 33]

Part 3 of the RMAR 2015 provides information relating to the creation, administration and termination of well management plans (WMP) and control of well integrity hazards and risks.

4.3.1 The WMP and its purpose

The WMP documents the history of all well activities relating to the planning, design, construction and management of a well throughout its life cycle through to and including its decommissioning. A WMP will most commonly relate solely to activities on one particular well, however, there is provision in the regulations for multi-well WMPs to be created. This would cover a group of wells in close proximity and with similar characteristics, for example, batch drilling directional wells from a single pad. It is Resource and Environmental Compliance Division's preference that each well has its own WMP.

The intent of Part 3 is to ensure that the WMP functions as a regulatory approval document and as a practical implementation and management tool to be used by the title holders, and their contractors, when conducting a well activity. The WMP should:

- be appropriate for the nature and scale of the activity
- be managed in accordance with sound engineering principles, codes, standards and specifications
- demonstrate that the risks of the activity will be ALARP
- be consistent with good oilfield practice
- demonstrate that the activity being carried out will not result in significant new detrimental risk or any significant increase in a detrimental risk.

All well activities must be conducted in accordance with an approved WMP covering the activity. Title holders will make an application for a WMP covering a well activity, to be approved.

In all cases of drilling a new well and planned activities on an existing well, there is the need to meet the requirements of the Petroleum and Geothermal Energy Resources (Occupational Safety and Health) Regulations 2010, the Petroleum and Geothermal Energy Resources (Management of Safety) Regulations 2010, and the Petroleum and Geothermal Energy Resources (Environment) Regulations 2012. Environment and safety requirements, as well as the WMP, must be approved before an activity can commence. Note that a well activity in a licence area must be undertaken in a manner consistent with the FMP for that area (see Part 6, r. 42).

Applications for new wells were previously accommodated under the old 'Schedule of Onshore Petroleum Exploration and Production Requirements 1991' in Part V, Clause 501, Approval to Drill. Under this clause, an 'Application to Drill' was submitted at least 90 days before the commencement of drilling and contained requisite information required to be circulated to the other relevant divisions within DMIRS.

An 'Application to Drill' online submission remains a necessary part of the approval process to drill a new well. This application will be accompanied by the initial submission of the WMP. This WMP will be the equivalent of a drilling program.

The provision of information in an 'Application to Drill' accommodates the needs for approval of land access and occupational health, safety and environmental issues controlled under their respective regulatory provisions. Whilst the approval of a WMP requires only 30 days for assessment, it is highly recommended that other plans relating to a new well application be submitted early in the approval process so that all assessments may be completed in a timely manner. The nature of the assessments performed by Resource and Environmental Compliance and Resources Safety divisions of DMIRS, in some instances, can take months to provide a determination.

4.3.2 How it works

The initial or first WMP submitted for a well will, once approved, cover the activity that is either currently occurring or is planned to occur at the time of the submission. For an application to drill a new well, the initial WMP will effectively be the drilling program. Every WMP should include the proposed well status and a well completion diagram that will apply following the execution of the subsequent activity.

If further documentation is added to the WMP after the approval is granted, the WMP is considered to be revised. The further documentation may take the form of correspondence or notifications about an activity on the well, but may also take the form of further well activity programs, which require approval before being added to the WMP.

This revision process also applies to 'management of change' within an activity covered in an approved WMP. The change to the activity cannot commence until the management of change has been approved.

Where the further activity program completely supersedes the original WMP, the latest addition will be considered to be the current WMP in force. For example, the initial WMP to drill the well is revised by a new WMP to test the well. However, a revision to a WMP does not mean that the original WMP with all its information must be revised and resubmitted by the title holder for approval.

Documentation of changes to an activity that potentially impacts the well's status or integrity will require approval. There will be occasions when operational changes to an activity will not impact on the status or integrity of a well. The documentation or notifications of the change will not need approval. In both cases, the documentation covering the change will revise the WMP.

Operational changes can be required at short notice and it may be possible to obtain verbal approval, with formal approval paperwork completed later, in order that necessary changes can proceed. However, it is desirable, wherever possible, that regard be given to the time needed for an assessment to be made.

4.3.3 Significant well activities defined

'Well activity' and 'each well activity' are defined in Part 1 – Preliminary [r. 4]. A well activity can denote any drilling, deepening or side-tracking, or other well interventions, and the operations performed in, or on, or relating to, the management of a well, including well testing, during the entire life cycle of the well, from initial drilling and completion to decommissioning. Significant well activities will require regulatory approval before they are undertaken. Approval is administered through the submission of a WMP or a revision to a WMP.

An activity is considered to be 'significant' where it changes:

- the risks associated with the well
- the well's configuration
- its function
- the well's integrity.

Significant activities can include, but are not limited to, the following operations:

- well drilling operations, including exploration, reservoir appraisal, field development, well deepening and side-tracking
- well completions planning and operations, including testing of completion assemblies and production
- well interventions, including well recompletions; well testing, including flaring; formation stimulation, including hydraulic fracturing, perforating and re-perforating; production logging; coil tubing operations; production testing; injection testing; workovers, suspension
- decommissioning, including notification of the proposal for the cessation of production operations.

Routine maintenance or data acquisition activities may not be deemed significant and may only require the title holder to notify DMIRS of their performance and of outcomes from such activities. The notification will revise the WMP. Clarification of whether notification for a particular activity will suffice may be obtained from the DMIRS' REC Division by emailing **petroleum.reports@dmirs.wa.gov.au**

4.3.4 Matrix outline of WMP submissions and management requirements

The matrix shown in Table 5 summarises the requirements for submissions of WMPs and other documents for activities and their risk details. Title holders should consult with the REC Division prior to submission to discuss the specific approach for the submission and management of proposed plans for activities.

4.3.5 WMP administration – The two Divisions and five Subdivisions of Part 3

Part 3 of the RMAR 2015 has been divided into two (2) Divisions. Division 1 of Part 3 provides instructions relating to the administrative requirements and processes concerning various phases during a WMP's life. Schedule 1 describes the information required in a WMP. Division 2 requires a title holder to control an identified well integrity hazard or risk. Each of the two Divisions is discussed below.

Table 5. Matrix showing WMP submissions and management requirements

Well activity (new or changed)	WMP in force	Risk considerations(2)	Initial WMP (1)	Written notification	Revision of WMP (1) (6)
New activity, including drilling	No	Risk assessment required	X		
New batch drilling	No	Risk assessment required for a multi-well WMP	X		
New drilling activity not covered in an approved multi-well WMP	Yes	New activity requires risk assessment			X
New well activity not covered in an approved specific or multi-well WMP that applies to that well, including decommissioning (P&A) (3)	Yes	New activity requires risk assessment			X
Routine maintenance (4)	Yes	No changes to risks		X	
Change in well activity covered in an approved specific or multi-well WMP (5)	Yes	Revision to risk assessment			X
During an activity covered by an approved specific or multi-well WMP	Yes	Changes in the understanding of the geology or reservoir that may have significant impacts on well activities			X
During an activity covered by an approved specific or multi-well WMP	Yes	The occurrence/potential occurrence of significant new detrimental risks to impact on a well activity			X
During an activity covered by an approved specific or multi-well WMP	Yes	A significant increase in a detrimental risk impacting a well activity			X

(1) Written approval of the WMP is required from DMIRS prior to undertaking the activity, except in the case of an emergency as described in the regulations.

(2) As per the title holder's risk assessment as outlined in risk classification (Figures 2 and 3).

(3) A WMP will contain risk assessment and details of activity programs that have occurred on a particular well (or wells in a multi-well WMP). There will be a current activity that is approved. A new activity proposed for a well will not yet be within the scope of a WMP, even if a similar activity has previously been completed under the approved WMP.

(4) The activity does not change the well profile or reservoir characteristics e.g. integrity testing, greasing valves, slickline gauge runs.

(5) A change in well activity will relate to the current activity in progress on a well (commonly called management of change).

(6) Except in the case of an expired WMP (after five years) when a new WMP is required, in practical terms, a revision of a WMP means the submission of an activity program (with risk management included) which, once approved, is appended to the existing WMP.

Division 1 has been further subdivided into five (5) Subdivisions.

Division 1 – Well management plan (WMP), this has five subdivisions:
Subdivision 1 – Requirements relating to approved WMP [r. 10 – r. 11]
Subdivision 2 – Obtaining approval of WMP [r. 12 – r. 18]
Subdivision 3 – Revision of WMP [r. 19 – r. 27]
Subdivision 4 – Termination of WMP [r. 28]
Subdivision 5 – Withdrawal of approval of WMP [r. 29 – r. 32]

Division 2 – Control of hazards and risks [r. 33]

Schedule 1 – Well management plan [r. 17(1)]

4.3.6 Division 1 – Subdivision 1 – Requirements relating to approved WMP [r. 10 – r. 11]

It is a regulatory requirement to have an approved WMP in force before any significant activity can be undertaken on a well. Information on the requirements and penalties applying to the administration of WMPs is found in r. 10(1).

It is a requirement to undertake well activities in accordance with an approved WMP [r. 11(1)]. The WMP process has been implemented to ensure a well is designed, and well activities are managed, in accordance with good oilfield practice, including the assessment and management of risks.

An exception to these regulations is provided for in the case of an emergency to allow a title holder to undertake an activity without an approved WMP [r. 10(2)] or not in accordance with an approved WMP [r. 11(2)] in order to avoid injury to persons, significant discharge of fluids, or damage to an underground formation, an aquifer or any other environmental damage.

In these emergency circumstances, it is a requirement to notify the Minister within two (2) hours of becoming aware of the emergency (duty officer +61 427 479 615) and for the provision of a written report to the Minister within three (3) days (email **petroleum.reports@dmirs.wa.gov.au**), describing the well activity undertaken.

4.3.7 Division 1 – Subdivision 2 – Obtaining approval of WMP [r. 12 – r. 18]

Subdivision 2 of the regulations provides for the following issues and actions in the process of progressing an application for the approval of a WMP.

Whilst r. 12 states the application must be made in writing at least 30 days, unless otherwise allowed by the Minister, before the proposed start of any activity, certain well activities will require longer lead times to accommodate more operationally complex activities. It is preferable that the WMP be submitted as early as possible to maximise the time available for approval, before the proposed starting date of the activity.

Application may be made for activities for more than one well [r. 12(3)(b)] in a multi-well WMP.

It is important to note that if further information is required by DMIRS to assess the WMP, the assessment process is paused until the information is received. This will have the effect of extending the time allowed for a decision under r. 13(1) for the application's approval, or further assessment of it. The Minister has 30 days from the application date to make a decision on a WMP, to either accept wholly or one part of the WMP, reject the WMP or notify the title holder that further assessment of the WMP is required. The regulation also allows the Minister to accept the WMP subject to conditions, and specifies how the Minister must notify the title holder of the decision [r. 14], as well as the date of effect of an accepted WMP being the same day as notification of acceptance [r. 15].

Records of relevant communications and agreed outcomes, arising during the consideration of a WMP, should be maintained to ensure mutual understanding by both parties.

Criteria for approval of the WMP are listed in r. 16. It is important to note that the WMP is meant to be fit for purpose. The application should contain all the required and relevant information. The WMP should:

- be appropriate for the nature and scale of the activity
- be managed in accordance with sound engineering principles, codes, standards and specifications
- demonstrate that the risks of the activity will be ALARP
- be consistent with good oilfield practice
- demonstrate that the activity being carried out will not result in significant new detrimental risk or any significant increase in a detrimental risk.

The WMP should address, as a minimum, the requirements under r. 17 *('Content of a WMP')*, and further detailed in Schedule 1 *('Well management plan')*. Schedule 1 lists 15 items covering the description of information that may be required to be included in the WMP. Some of the 15 items will always be necessary, others might not be necessary for particular activities. Schedule 1 is further discussed under heading *4.3.12 RMAR Schedule 1 – Well management plans [r. 17(1)]*.

With the permission of the Minister, the title holder may submit a WMP in parts; the first part is taken to be an accepted plan in its own right and the part(s) subsequently given to the Minister are treated in the same way as a revision to the plan [r. 18(1)]. Additionally, the Minister may approve a WMP in parts; the first part is taken to be an accepted plan in its own right and the subsequent part(s) given to the Minister after that are treated in the same way as a revision to the plan [r. 18(2)].

There can only be one approved WMP in place for a well (for a single well WMP) or group of wells (for a multi-well WMP). If a WMP is approved to replace an existing WMP, then the previously existing approved WMP ceases to have effect. In this case, the new WMP is not provided as a revision to the previously approved WMP, but as a replacement.

4.3.8 Division 1 – Subdivision 3 – Revision of WMP [r. 19 – r. 27]

A title holder may apply for approval of a revision of an approved WMP under r. 19. The regulation merely states that a title holder may apply for approval of a revision and the application must be accompanied by the proposed revision covering a new activity or change within an activity.

If a well is re-entered after the initial period of drilling for any purpose (other than drilling to a new target) that will materially change the down-hole configuration and construction details, including when a production well is subsequently plugged and abandoned or a previously suspended well is brought online, the activity must be covered in a revision to the WMP. Drilling to a new target would require a new well application.

There are some circumstances that must lead to a revision application [r. 20]. These include changes to the understanding of the geology or underground formation that might potentially impact well integrity, or changes in the risk assessment that could impact well integrity.

In the case where a revised well activity significantly increases the risks, or are different to or were not previously addressed in the original WMP, then the analysis, management and mitigation of these risks should be included in the proposed revised WMP.

DMIRS will assess the revision document and ensure that it is appropriate before approving the revision of the WMP. The assessment timeframe for a revision is 30 days and is covered by regulations r. 21 through r. 23.

There are circumstances in which the Minister may require a title holder to revise an approved WMP by giving a written notice [r. 24]. This notice will state the technical grounds for requiring a revision and the date by which the revision should be submitted, and the effective date of the revision.

Under r. 25, the title holder may object in writing to a notice given under r. 24, giving reasons for the objection, within 21 days of receiving the notice of the Minister's requirement to vary the WMP. The Minister has 30 days to make a decision on the objection [r. 26] and advise the title holder who must then comply with the Minister's decision with respect to the notice [r. 27].

4.3.9 Division 1 – Subdivision 4 – Termination of WMP [r. 28]

A WMP may be terminated under r. 28, which lists the conditions under which an accepted WMP ceases to be in force, including the title holder withdrawing the WMP; the Minister accepting a replacement WMP; the Minister withdrawing approval of a WMP; or after five (5) years from when the WMP was first approved.

4.3.10 Division 1 – Subdivision 5 – Withdrawal of approval of WMP [r. 29 – r. 32]

Regulations r. 29 through r. 32 relate to circumstances where the Minister believes it may be necessary to withdraw approval of a WMP. That is: the title holder has not complied with the Act, Part 3 of the RMAR 2015 or a direction given under section 95 of the Act; or the title holder has not complied with the WMP; or the Minister is satisfied for any other reason that approval of the plan should be withdrawn.

The Minister must give a written notice to the title holder that the Minister is considering withdrawing approval at least 30 days before approval is withdrawn. Included in the notice is a date by which the title holder may give information that the title holder wants taken into account before the Minister makes a decision on withdrawing approval. Once the Minister has made a decision on withdrawing approval of a WMP, the title holder must be givenwritten notice.

4.3.11 Division 2 – Control of hazards and risks [r. 33]

Title holders operating a well in a title area are required to control a well integrity hazard that has either been identified for the well or where there has been a significant increase in an existing risk for the well.

4.3.12 RMAR Schedule 1 – Well management plan [r. 17(1)]

Schedule 1 provides guidance pertaining to the contents of a WMP or a revised WMP. It lists and describes information concerning 15 items, together with a number of sub-lists. The content of a WMP will vary as a function of the nature of the planned activities in a well. Some items are common to all WMPs and others are activity specific. Items 1 to 7, 12 and 14 will invariably be included in all WMPs. The title holders should review the list provided in the Schedule and use their discretion to determine which items are relevant to their WMP application. The Petroleum Compliance Branch, REC Division should be consulted if any uncertainty exists. Most of the items are self-explanatory. Note that the WMP should include only those items in the Schedule that are applicable to the particular current or proposed activity covered under the WMP.

The format of the WMP is not standardised and the items mentioned in the Schedule will not necessarily be found in the WMP document in the same sequence as the Schedule. The format is more a function of what suits the title holder and their documentation process. For example, item 3 (description of activity) may also include item 5 (timetable) within it.

4.3.12.1 Schedule 1 Item 1 – Name and number of the well

The WMP and any correspondence relating to the well should always state the name and number of the well.

4.3.12.2 Schedule 1 Item 2 – Location of the well

Details of elevation, latitude and longitude, permit or title number, basin and sub-basin, map sheet name and graticular block number are required information. This information is usually included in a well index sheet found at the beginning of the WMP.

Please note, the bottom hole location determines which title the well is situated in and is therefore especially important if the bottom hole location graticular block is different to the surface hole location graticular block.

4.3.12.3 Schedule 1 Item 3 – A description of each well activity

This will be a summary of the purpose of the activity plus a detailed program that covers the activity. This item of the WMP should also include:

- table of casing details
- downhole schematics
- surface tree or BOP schematics
- well barrier table
- pressure test schedule
- a site plan.

For example, a WMP for a drilling a well will include the drilling summary and a detailed drilling plan, while a care and maintenance WMP might only have a paragraph or two describing the intent and frequency of conducting maintenance and testing the integrity of the well. Programs should also mention what the next potential activity will be on the well.

4.3.12.4 Schedule 1 Item 4 – An explanation of the philosophy of, and criteria for, the design, construction, operational activity and management of the well and the possible production or injection activities of the well

The title holder should include a statement that declares that principles such as sound engineering, a two barrier philosophy and adherence to good oilfield practice will be followed. It is a commitment that the standards mentioned in Schedule 1, Item 14 will be adhered to.

4.3.12.5 Schedule 1 Item 5 – Proposed timetable for the activity

There will always be a requirement for some information in this regard. The WMP should state the planned commencement date, there should be an estimate in most cases of how long the activity should take (end date) and there should be a table that details the time allocated for each step in the activity.

In a care and maintenance or a production WMP, there would not be a requirement for such specific detail but mention should be made of the frequency of maintenance and integrity checks. A suspension WMP should mention the frequency of maintenance and integrity checks once the suspension has been carried out, and also the length of time it is anticipated that the well will be suspended for.

4.3.12.6 Schedule 1 Item 6 – Performance objectives and measurement criteria

Performance objectives are the aims or targets to be achieved during the activity or fulfilled by the completion of the activity. These objectives may be a succession of targets that occur in sequence during the course of the activity, or a single objective, such as obtaining specific data, or the successful completion of a procedure during the activity. An objective will commonly delineate the end of a particular stage in the activity that must be completed before the next stage can continue.

The measurement criteria may be quantitative or qualitative to determine if a performance objective has been met. In some cases, an objective may have been met but the end result was not a success. For example, the performance objective may be to run wireline logs without getting stuck. The logging operation might be completed successfully, achieving the objective, but the data obtained was not useful, for some other reason unrelated to the logging.

Measurement criteria may relate to:

- certain procedures or requirements being followed and successfully completed
- certain equipment being in place and in service
- successful completion of a well activity
- the collation of data and maintaining and keeping of records
- establishing the presence or absence of a particular condition.

4.3.12.7 Schedule 1 Item 7 – Well integrity hazards and significant increase in existing risk

It is a requirement that risk analysis be conducted on the activity and a tabulation of this analysis included in the WMP. The risks to be considered here pertain to well integrity rather than health, safety or environment (HSE). However, some well integrity risks can have adverse effects on HSE and vice versa.

The principle of ALARP should be applied. Mitigations that reduce risks to ALARP should be mentioned in the table. It should also be considered that even if a risk is reduced to ALARP, it still might have too high a rating for the risk to be undertaken.

4.3.12.8 Schedule 1 Item 8 – Details of chemicals and other substances

This item refers to the fluids prepared on surface and introduced into the well. These fluids include drilling mud, cement, completion fluids, packer fluids and hydraulic fracture fluids. Details of the chemicals are to be provided as a list of product names or generic product types and their purpose (e.g. barite – weighting agent; polymer – viscosifier).

Detailed chemical disclosure, including CAS numbers, is required under the environmental regulations and is not required here. 'Other substances' refers to products such as lost circulation materials, which are contingency items.

4.3.12.9 Schedule 1 Item 9 – Proposed total volumes and composition of fluids and other materials used in the course of each well activity

This item relates to the proposed volumes of fluids mentioned in item 8 above. Composition means the primary description of the fluid. For example: KCL PHPA drilling mud; Synthetic Oil Based Mud; NaCl/KCl completion brine; Friction Reduced Fracture Fluid; Cross Linked Fracture Fluid. It also means the total volume or weight of materials, such as proppants, that are to be introduced into a well during a well activity.

4.3.12.10 Schedule 1 Item 10 – The estimated total volume and composition of returned fluids and other materials from the well and arrangements for the management of those fluids and materials

This item relates to fluids and materials that have been introduced into the well and that have been recovered from the well.

Examples of this:

- The estimated volume of drilling fluid that will be disposed of on surface during the drilling of a well and the site of disposal of these fluids (i.e. fluid removed by solids control equipment and excess fluid that will be disposed of in a settlement pond or carted away).
- The estimated total volume of completion fluid that will be displaced out of a well during a workover and where will it be disposed of.
- Where sand, recovered during flowback after a hydraulic stimulation, will be disposed of.

4.3.12.11 Schedule 1 Item 11 – Arrangements for the management of any produced formation materials that result from drilling, well testing or production

This item relates to gaseous, fluids or solid materials that were in the subsurface rock formations and have been produced to surface. It includes rock cuttings and cores obtained during the drilling of a well; hydrocarbons produced during a test or during production; formation fluid that is produced during a test or production; and material, such as sand, that is produced during production. Management includes collection, recording and disposal of the materials.

4.3.12.12 Schedule 1 Item 12 – Details of when and how the title holder will notify the Minister, and give the Minister reports and information about – each well activity and well integrity and significant increases in existing risks for the well and other matters relevant to the conduct of each well activity

This item related to how the title holder intends to inform the Minister about the ongoing conduct of each well activity, when reports will be sent and how and when the Minister will be informed about unforeseen events.

4.3.12.13 Schedule 1 Item 13 – An explanation of the way that the title holder will keep information required by the well management plan

This item relates to record keeping and means the retention of information about the well activity or obtained by the well activity. The title holder must describe how that information will be retained and managed.

4.3.12.14 Schedule 1 Item 14 – A list of the principal Australian and international standards that apply in relation to each well activity and plant used in connection with each well activity

This item requires a list of the particular standards that the title holder is going to apply to their well activity. This means a list of the appropriate API or NORSOK standards that might apply; for example, the API HF standards for hydraulic fracture stimulations.

It is possible that a title holder might apply a standard of their own. This case would necessarily include more detail than just the name of the standard, as would occur with a commonly known and accepted standard. The standard would then be examined to see if it was equivalent to and consistent with a commonly known and accepted standard.

4.3.12.15 Schedule 1 Item 15 – For WMPs relating to a drilling activity

A WMP for a proposal to drill a well will usually require all the items in Schedule 1 to be included. Item 15 lists 14 particular requirements that must be addressed in the WMP, which may have been covered under a different item number. For example, the proposed timetable in Item 5 would include the spud date.

4.4 RMAR Part 4 – Discovery assessment reports [r. 34 – r. 36]

The discovery of petroleum or geothermal energy resources triggers the requirement for the title holder of exploration permits, drilling reservations, and retention leases to notify the Minister within three (3) days in writing. Particulars to be provided will include the date of discovery, well name, title and graticular block location of the well, depth and thickness of discovery, how the discovery was made (e.g. logs and well test), and any physical and chemical properties of the petroleum or geothermal energy that are known [r. 34]. Notifications should be sent to **petroleum.reports@dmirs.wa.gov.au**

Discovery of petroleum or geothermal energy means the initial recovery of any naturally occurring petroleum or geothermal energy in a petroleum or geothermal title. Recovery implies that resources or energy must be brought to the surface from a known depth and geologic formation, in sufficient quantities for laboratory analysis of the composition.

Under r. 35 the Minister can, within seven (7) days of being notified, request further information from the title holder that is to be included in the discovery assessment report.

The initial notification is followed by the submission of a discovery assessment report. This report ensures that the Minister is informed of the discovery and its initial appraisal in a timely and consistent manner.

To request further guidance from the department on discovery assessment report submissions, please email **petroleum.reports@dmirs.wa.gov.au**

The requirements and contents of the discovery assessment report are listed under r. 36(1). Guidance regarding the contents of this regulation includes:

(a) The title area in which the discovery was made and the location of the discovery well. The discovery name is usually based on the well name; if a different name is requested, please indicate. The map sheet, graticular block of the bottom of the well, and closest seismic line(s) should be noted.

(b) A preliminary estimate of the location, areal extent (in km^2) of the petroleum pool or geothermal resource area and, if applicable, the resource column height. The methodology for estimating the areal extent of the resource should be described, especially for shale, tight gas, or geothermal resources. If the pool or geothermal resource extends outside the title area, provide an estimate of how much of the entire resource is contained within the title area.

(c) Details of the geological structure or underground formation in which the petroleum or the geothermal energy resource is located, with particular emphasis on the depth of recovery. Geological structure descriptions should provide an overview of the basin and sub-basin. For geothermal discoveries, please discuss heat flow regimes.

(d) The results of all assessments of the discovery, including well operations. A well summary sheet should be provided. Also include the chemical composition and physical properties of the petroleum or geothermal resource. At a minimum, the properties should include the chemical composition, reservoir temperature and pressure, density and viscosity. For petroleum, additionally include at least the petroleum fractions, gas/oil ratio and dew point or bubble point pressure. For geothermal resources, additionally include at least the thermal conductivity and radioactivity content (U, K, Th). Laboratory and field testing reports should be appended to the discovery assessment report.

(e) The rate or quantity of production of petroleum and water, or geothermal energy and water, from the discovery well, if it has been determined. Detail the injection and recovery fluid compositions and properties, if any, to determine the originof any recovered water. If downhole sampling was utilised for recovery, detail the recovery method, e.g. coring or MDT samples.

(f) The data used to estimate the quantity of petroleum in the petroleum pool or the quantity of geothermal energy resource in the geothermal resources area. Details of the core, seismic or wireline log data available should be provided. Seismic cross sections through the discovery well are desirable.

(g) A preliminary estimate of the quantity of recoverable petroleum in the petroleum pool or the quantity of recoverable geothermal energy in the geothermal resource area, in metric units. The in-place resource quantity should also be included, as well as a brief discussion of the methodology used to estimate volumes and recovery factor. The Society of Petroleum Engineers' (SPE) Petroleum Resources Management System (PRMS) and associated guidelines is the preferred method for determining the quantities and likelihoods (P10/P50/P90 or low/mid/high cases) of petroleum resources contained in the discovery. However, the discovery assessment report does not require a discussion of the commerciality of the resource.

(h) Details of the title holder's plans for further evaluation of the discovery should include the work that the title holder proposes to carry out in the title area in the 12 months following the date of the discovery assessment report.

(i) If the Minister has requested further information under r. 35, then this should be included in the report.

Maps provided should be legible and in high resolution (at least 300 dpi) and include appropriate scales, cadastral boundaries, and cross sectional locations. Cross sections should indicate horizontal boundaries (such as graticular blocks or title boundaries) and intersections (or map projections) of nearby wells.

The discovery assessment report is due within 90 days after the date of the discovery, or at a different period authorised by the Minister [r. 36(2)(a) and (b)].

4.5 RMAR Part 5 – Annual assessment reports [r. 37 – r. 39]

This Part details the requirements of a title holder in regard to the provision of annual reports to be submitted to DMIRS, as per the requirements of r. 37 – r. 39 of the RMAR 2015. Specific requirements for annual reporting are detailed in Schedule 2 – *'Annual assessment report'*.

4.5.1 Requirement to provide annual assessment report [r. 37]

Annual assessment reports (previously known as an annual title assessment report) provide the Minister with information on the exploration for or development and/or extraction of, a petroleum or geothermal energy resource within a title area. The annual report covers a 12 month period beginning on the anniversary of the grant or renewal of the title. The title holder is required to submit an annual assessment report within 30 calendar days of the end of each year of the term, unless the Minister authorises submission within another period [r. 37(1)].

The information required in an annual assessment report [r. 37(2)] is related to the type of title, as listed under the Divisions of Schedule 2 – *'Annual assessment report'*. These include information required of a permittee or holder of a drilling reservation (Division 1), of a lessee (Division 2) and of a licensee (Division 3).

An annual report must be submitted irrespective of whether any operational work or activity has occurred. These reports are used in assessments of renewal and surrender applications.

4.5.2 Reports may be combined [r. 38]

A title holder with more than one title may combine reports into one document [r. 38]. Written agreement from the Minister is required.

4.5.3 Assessment report for part of year [r. 39]

In cases where a title ceases to be in force, e.g. owing to a title surrender, or the term of the title was not in force for an entire year, r. 39(1) provides for reporting on part of a year. For example, if a permit was extended by six (6) months, the title holder must submit a report 30 calendar days after the end of that final six (6) months.

The Minister may also require, by written notice, the title holder to give an assessment report at the end of a term that was not a full year [r. 39(2)]. If a notice is given [r. 39(3)], it will specify the information to be provided, subject to r. 39(4), and the date by which the report must be given. That date will be at least 30 days from the date of the notice [r. 39(5)].

Annual assessment reports should be lodged online via PGR using the data submissions tab. Any requests for changes to standard reporting should be sent to **petroleum.reports@dmirs.wa.gov.au**

4.5.4 RMAR Schedule 2 – Annual assessment report [r. 37(2)]

Division 1 itemises the required information for a permittee or holder of a drilling reservation, under Items 1-5. Division 2 itemises the required information for a lessee, under Items 6-12. Division 3 itemises the required information for a licensee, under Items 13-22.*

Note that Items 1 to 5 in Division 1 are the same as Items 6, 7, 8, 10, and 12 in Division 2. Permittees, holders of drilling reservations and lessees must all submit the following in annual assessment reports:

- Items 1, 2 and 6, 7 – a description of work and expenditure commitments for the year, including results of the work, evaluation or studies, total expenditure, and details of prospects and leads.
- Items 3 and 8 – a list of reports that have been submitted to the Minister during the year.
- Items 4 and 10 – a description of work, evaluations, studies and expenditure commitments for the next permit year, as well as the preparations taken for this work.
- Items 5 and 12 – any other information required by condition on the permit or drilling reservation.

* The following guidance notes have been prepared for annual reporting: Notes to accompany the Exploration Permit Annual Assessment Report Template. Notes to accompany the Retention Lease Annual Assessment Report Template. Notes to accompany the Production Licence Annual Assessment Report Template

In addition to the items listed above, lessees must include the following in annual assessment reports:

- Item 9 – detailed plans and work programs for the evaluation of known discoveries.
- Item 11 – in every year after lease Year 1, each petroleum pool or geothermal resource should be described, including:
  - any newly evaluated information
  - estimates of the quantity and recoverable quantity of petroleum or geothermal resource at the end of the previous year
  - how these estimates were calculated. (The preferred method of estimating is by using the SPE PRMS using metric units.)

Under Division 3, licensees must submit the following in annual assessment reports (Items 13-22):

- Item 13 – details of activities planned to be conducted in the area as a condition.
- Item 14 – a list of reports that have been submitted to the Minister during the year.
- Item 15 – detailed plans for further evaluation of the licence area. This means a description of work and expenditure commitments plus any work planned that has not been included in item 13 *(Note: not item 1 as stated in the RMAR 2015)*.
- Item 16 – a production forecast for each development or potential development.
- Item 17 – a description of any leads or prospects in the licence area.
- Item 18 is the same as Item 11 above, except it covers licence year.
- Item 19-21 – totals of petroleum or geothermal energy produced, injected, flared or vented during the year.
- Item 22 – any information that is required by a condition placed on the licence should also be included in the report.

Petroleum or geothermal energy resources in place and reserves information under Items 11 and 18 should be submitted in metric units using the Excel template that may be requested from DMIRS by sending an email to **petroleum.reserves@dmirs.wa.gov.au**

Annual assessments reports of all types may also contain any other relevant information that the title holder would like to include.

4.6 RMAR Part 6 — Field management plans for petroleum recovery [r. 40 – r. 61]

In order for recovery of petroleum from a petroleum field to be authorised, a title holder needs both a production licence in force and an approved field management plan (FMP). Part 6 of the RMAR 2015 provides information about how an FMP is applied for and assessed under these regulations. Schedule 3 of the RMAR 2105 provides information about the content of the FMP.

4.6.1 The FMP and its purpose

The FMP is a document describing how a licensee will develop and subsequently manage the petroleum resource for the lifecycle of the field within their title areas. It covers the period from the planning of the field development through to the decommissioning and rehabilitation of the field and ultimate surrender of the licence.

The FMP will detail all the resource management activities that will safeguard the resources and ensure that they are recovered in the best public interest, optimising short- and long-term benefits to the Western Australian community.

An FMP can only be submitted by a production licensee, or a production licence applicant. It details the evidence and data showing the extent and location of petroleum pool(s) and describes the proposed field development of the pool(s), the management and the recovery of the resources and associated production facilities, and waste management. It also contains details of any aquifers that may be affected by petroleum development and how those aquifers may be managed, including baseline monitoring. The document must include details of the applicant's plans for the closure of the field, including plans for decommissioning and rehabilitation of the field.

4.6.2 FMP objectives and requirements

An FMP is a technical document outlining the management of a proposed petroleum field development and associated activities. It has the objectives of ensuring that petroleum operations are carried out in accordance with good oilfield practice, and that these activities are compatible with the optimum long-term recovery of petroleum (i.e. at a sustainable rate, without adverse effects on the reservoir or unnecessary loss of associated resources).

Applications for revisions to vary the plan may be made. The FMP is a living document and will necessarily evolve as new information is obtained and circumstance change, such as variations in operating practices after production start-up, management of production facilities, and change in emphasis on longer-term development issues or options.

The goals of the FMP are to ensure that the Minister understands that:

- An adequate effort has been made to understand the geology of the licence area and that these efforts will continue.
- Alternative options have been assessed for optimising the development of petroleum, considering resource management, environment and safety impacts.
- The FMP addresses means of providing appropriate operational flexibility to enable development of additional reserves should they be discovered or be proven up in the licence area during the life of the field and subsequent to the approval of the initial FMP.
- The licensee/applicant has identified the technical risks (resource management risks and impacts) to production facilities and resource management associated with the FMP, as well as measures to monitor and address these risks.
- There is an experienced-based and/or reservoir modelling assessment of the projected production profile for the life cycle of the field and that there are plans in place for the closure of the field including the decommissioning plans, for removal of equipment and rehabilitation.

Note that if there is more than one field in a licence area, each field requires its own approved FMP. FMPs may be combined into one document with the written permission of the Minister.

Online lodgement is available for FMPs on the DMIRS website through the Petroleum and Geothermal Register (PGR) portal (**www.dmirs.wa.gov.au/PGR**).

4.6.3 The five Divisions of Part 6 – FMP administration

RMA Part 6 includes five (5) Divisions and contains regulations r. 40 through r. 61, and carries one schedule [Schedule 3 r. 48(1)]:

Division 1 – Preliminary [r. 40]
Division 2 – Field management plans requirements [r. 41 – r. 42]
Division 3 – Obtaining approval of field management plan [r. 43 – r. 48]
Division 4 – Revision of approved field management plan [r. 49 – r. 57]
Division 5 – Recovery of petroleum before field management plan approved [r. 58 – r. 61]
Schedule 3 – Field management plan [r. 48(1)]

4.6.4 Division 1 – Preliminary [r. 40]

In Division 1, Preliminary, r. 40 defines 'licence' and 'licence area' in relation to their reference in this Part. A licence means a petroleum production licence as defined in the PGERA67 and PSLA82. Only a production licence holder, or an applicant for a production licence, can apply to the Minister for approval of an FMP.

4.6.5 Division 2 – FMP requirements [r. 41- r. 42]

Division 2 discusses the requirements to have an approved FMP in force for the recovery of petroleum. A licensee, or an applicant for a licence, under most circumstances, must have DMIRS approval of an FMP prior to undertaking the recovery of petroleum in a production licence area [r. 41]. There are provisions for the extraction of petroleum without an approved plan where the recovery is on an appraisal basis [r. 41(a)] or where recovery of petroleum is approved under [r. 41(b)(ii)] as provided for in Division 5, r. 58(1) and r. 59(1) (see heading 4.6.8). In each case justification must be supplied to the Minister. Well activities undertaken throughout the licence area must be consistent with the approved FMP [r. 42]. Note that well activities must be in conducted in accordance with an approved WMP (see heading 4.3.6).

4.6.6 Division 3 – Obtaining approval of FMP [r. 43 – r. 48]

Division 3 outlines the process of obtaining approval of an FMP and discusses the application for approval of an FMP, the content requirements of the plan and the decisions and criteria relating to the timing and granting of approval by the Minister.

The title holder should allocate time for close consultation with DMIRS and the Petroleum Compliance Branch, REC Division to ensure a full appreciation of the approval process is established early in the planning stages.

As previously stated, only a licensee or an applicant for a licence may apply for approval of an FMP, and this application must be accompanied by the plan [r. 43]. Applications should be submitted online through the PGR system. The Minister is not subject to a strict timeframe to approve or refuse the FMP, but must do so as soon as practicable [r. 44(1)], otherwise must give written notice to the applicant if unable to make a decision about the application without further information and advising when further assessment will commence [r. 44(2)]. The regulation allows the applicant a reasonable opportunity to modify or resubmit the plan, after which the Minister will reassess the plan and may impose conditions on the approval of an FMP.

The Minister must notify the applicant of the decision to approve or refuse a field management plan [r. 45], as well as any condition(s) and the reason(s) for it, or conversely the reason for refusal of an application.

The approval includes the rate of recovery as specified in the FMP. An approved FMP takes effect on the date the Minister specifies in respect of the plan [r. 46]. This date will be the date of the notice given under r. 45.

Records of relevant communications and outcomes agreed with DMIRS, during the compilation period of an FMP, should be maintained to ensure that there is a common understanding of the agreements by both parties.

Criteria for approval of the FMP are listed in r. 47. The application should contain all the required and relevant information. The FMP should demonstrate that the field will be managed:

- in accordance with sound engineering principles, codes, standards and specifications
- in a manner that is consistent with good oilfield practice and compatible with the optimum long-term recovery of petroleum.

The FMP should address, as a minimum, the requirements under r. 48 *('Content of field management plan')*, and further detailed in Schedule 3. Schedule 3 is further discussed under heading 4.6.9 RMAR Schedule 3 – Field management plans [r. 48(1)]. The applicant may include any other information they believe to be relevant to the application.

Applicants are encouraged to provide as much relevant information as possible to support the proposed development. Additionally:

- All data should be supported with figures (maps, well logs, correlations, screenshots, models, cross sections, etc.) and should be high resolution (300 dpi) and at least in A4 format. Attach figures as separate files rather than pasting the image into the FMP submission. In this way high resolution will be maintained.
- Important or detailed figures (especially well logs and correlations) should be in A3 format, with clearly visible and legible headers and scales.
- Cross sections including seismic sections should be shown on structure maps and demonstrate the location of wells clearly.
- All numerical data must be in metric units and, if desired, in field units.

4.6.7 Division 4 – Revision of approved FMP [r. 49 – r. 57]

A licensee may apply for approval of a revision of an FMP under r. 49; the application must be accompanied by the proposed revision. Again, application for a revision should be submitted via PGR. The online submission process allows for only portions of the FMP document to be revised as needed.

In accordance with r. 50, the licensee must apply for a revision if it intends to make a major change in relation to the recovery of petroleum from the field or a pool in the field. A major change can be an event known in advance or anticipated by the licensee and can be addressed as appropriate in the FMP revision in advance. Major changes can include (but are not limited to):

(a) changes by the petroleum licensee to the development strategy or management strategy of the field or of a petroleum pool in the field (e.g. increases in the rate of recovery or a revised ultimate recovery or reserves; changes to the production forecast; configuration of wells in the field; additions or modifications to a production facility, other than for the purpose of maintenance)
(b) changes by the petroleum licensee to the plan for the development of additional petroleum pools in the field (e.g. recovery from previously unconsidered geological formations)
(c) the petroleum licensee ceases production, permanently or for the long term, before the date proposed in the approved FMP
(d) the petroleum licensee introduces new methods for the recovery of petroleum from the field, such as enhanced recovery and injection of fluids.

The application for approval of a revision of an FMP must be made at least 90 days before making the major change [r. 50(2)].

DMIRS, having already approved the FMP being revised, will assess the revisions to the earlier FMP. If satisfactory, DMIRS will issue approval of the revision. The assessment timeframes are the same as the initial assessment.

The Minister can also request the licensee to revise the approved FMP under r. 54 and licensees may object in writing to a notice by the Minister to revise an approved FMP [r. 55].

Note that 'significant events' discussed in Part 7 may also cause a revision to an FMP. Significant events are changes to the understanding of the field or risks associated with recovery, or an event or incident that is not under the direct control of the licensee and was not planned by the licensee. Significant events require oral notification to the Minister within two (2) hours, and written notification within three (3) days. Most significant events, such as a new or increased risk to the recovery of petroleum within the licence area, will lead to a major change in resource recovery strategies and require the revision of an FMP. See more details about significant events in section 4.7 Part 7.

4.6.8 Division 5 – Recovery of petroleum before FMP approved [r. 58 – r. 61]

Division 5 reviews the issues and circumstances relating to the recovery of petroleum from a licence area, without an approved FMP in place. This Division enables the Minister to approve recovery of petroleum performed before sufficient information exists to create the FMP. Under r. 58(1), the Minister can approve an application for recovery of petroleum, without an approved FMP, for a period of up to three (3) months.

If an extended production test (EPT) is desired, a revision of a WMP must also be submitted for approval (see section 4.3.8 – Subdivision 3 of WMPs [r. 19 – r. 23]).

An EPT program is a means of gaining information necessary to create the FMP. The main reason underlying a need for an EPT is that the available data indicated there is a high level of uncertainty relating to key control parameters that are needed to further the development of the FMP. The program submitted with the application for an EPT should indicate the objectives that a test will fulfil. The methodology for obtaining the objectives should be provided, with particular emphasis on the monitoring and data gathering aspects of the testing. Risks to the attainment of the objectives, and mitigation measures, should be discussed.

Approval by DMIRS is required before recovery can commence. An application to recover petroleum without an FMP in place should be submitted to the Petroleum Compliance Branch via **petroleum.reports@dmirs.wa.gov.au**. Under r. 58(2), the application must include reasons for the test, the period for which approval is sought, the details of the test and the details concerning proposed flaring of produced petroleum or disposal of produced formation material.

The approval of an application for production before an FMP is approved will require the provision of information to address the following (at a minimum):

- Log and other drilling controls indicated the presence of hydrocarbon-bearing rocks that are potentially reservoir quality and productive. Analogous reservoirs can be referenced to illustrate the potential of flow given assumptions relating to the similarities of their static data.
- Data was acquired through well testing, or other means, supporting the deduction that the hydrocarbons are potentially moveable and therefore recoverable, but estimation of a recovery factor is highly speculative.
- The well tests and data acquisition surveys conducted did not provide sufficient, or definitive, key information concerning such items as:
  - reservoir pressures and the nature of any reservoir drive mechanisms
  - formation transmissivity and the extent of well bore damage
  - stabilised or declining flow rate trends and deliverability
  - lateral (connective pore volume) extent and any compartmentalisation
  - additional estimates of potential hydrocarbons in place.

The Minister is not subject to a strict timeframe to approve or refuse the application for recovery of petroleum, but must do so as soon as practicable [r. 59(1)], otherwise must give written notice to the applicant if unable to make a decision about the application without further information [r. 59(1)(c)]. The notice must specify the further information required [r. 59(2)]. The Minister must approve or refuse the application as soon as practicable after receiving the further information [r. 59(3)]. The application may be approved subject to conditions [r. 59(4)].

The Minister must notify the applicant of the decision to approve or refuse the application [r. 60], the permitted period for which recovery is approved, as well as any condition(s) and the reason(s) for it, or conversely the reason for refusal of an application.

The permitted period must not exceed three (3) months after the date of approval of the application [r. 61(1)]. Under r. 61(2), the period may be extended by not more than three (3) months and under r. 61(3) the test period may be extended more than once on written application by the licensee.

4.6.9 RMAR Schedule 3 – Field management plan [r. 48(1)]

Schedule 3 provides information related to the FMP content requirements in descriptive information within a list of 17 items. The licensee is required to provide all relevant and sufficient information to adequately accomplish the objectives of the plan.

The content of each section of the FMP should reflect or address the requirements of the RMAR 2015, and should:

- contain all the required information
- be appropriate for the nature and scale of the activity or proposed use
- comply with the PGERA67 or PSLA82, all relevant petroleum regulations and applicable State statutes.

The methodologies applied in the assessment of resource quantities (hydrocarbons-in-place and recoverable reserves) should be governed by the SPE PRMS reporting system. Planning and the progressing of the FMP submission should be discussed with DMIRS during the early stages of the project.

It is not necessary in the FMP to address the items in the same order as Schedule 3, but content addressing the scheduled items must be included somewhere in the FMP. The online submission via PGR utilises a format and layout of information which is considerably different than the order of Schedule 3 and reflects a typical report format. Guidance on the online FMP application may be obtained in the document linked FMP application.

4.6.9.1 Schedule 3 Item 1 – Evidence and data showing that the field contains petroleum, including details of the structure, extent and location of discovered petroleum pools

Evidence and data referred to in Item 1 will include descriptive text, location maps and cross sections through the resource area, which define the 3D extent of the resource. Information provided should refer to geological formations, and the nature of the rocks containing the petroleum pool. Regional geology including faults, stratigraphy, formation depths, lithology, subsurface mapping, and reservoir parameters should be included. Spatial units must be in metres or kilometres.

History of previous exploration that provides evidence for petroleum and the evidence itself should be included – e.g. details of core analyses, tests. Include mapping and commentary to support any seismic depth studies, structural maps and results of interpretations.

4.6.9.2 Schedule 3 Item 2 – Estimates of the volume of petroleum in place and recoverable petroleum, including data supporting the estimates

The assumptions for determining recoverable petroleum for each reservoir zone in the field should be clearly set out and justified. Data should be tabulated and include gas, condensate, oil, and inert gases, both in place and recoverable. Note the requirement for metric units.

4.6.9.3 Schedule 3 Item 3 – A description of the following:

(a) the possible petroleum pools in the field
(b) the applicant's plans (if any) to explore for petroleum pools
(c) how any petroleum pools of commercial quantity can be incorporated into the development of the licence area

A description of: any further known prospects in the licence area that have not yet been evaluated; how and when further exploration is intended to occur to evaluate known prospects or to locate any as yet unknown prospects; and how petroleum pools of commercial quantity can be developed. This description may have the firm intention to develop a known commercial petroleum pool and method of developing pools that have potential to be commercial but are not yet proven. Flexibility of the plan to accommodate future discoveries is required.

4.6.9.4 Schedule 3 Item 4 – A description of the following:

(a) an appropriate strategy for the development of the field, management of petroleum pools and optimum long-term recovery
(b) any proposed and alternative development scenarios

Item 4 (a) entails a description of the preferred development methodology, including its management over the lifetime of the petroleum field and an estimate of amount of petroleum resource expected to be recovered over the lifetime of the field. It should address the production of associated fluids. Item 4 (b) requires consideration of alternate potential commercial developments of the petroleum field, if appropriate, and an explanation of why the preferred development strategy has been chosen.

4.6.9.5 Schedule 3 Item 5 – A description of how the applicant intends to recover petroleum over time, including the following information:

(a) the estimated position of wells
(b) the potential timing of workover operations
(c) possible tie-ins

A description of how all petroleum pools in the licence area will be incorporated into the proposed development should include pools that are commercial now, as well as those that may not be commercial on a stand-alone basis, but could be commercial if combined with other pools in the licence area. In the initial stages of a petroleum development it is expected that the estimated position of wells may only be described. Detailed descriptions of the well locations are included in the WMP (see section 4.3). However, as the development of the petroleum field progresses, it is expected that details of additional drilling, workover operations and tie-ins will revise an approved FMP. As per r. 42, well activities in the field must be consistent with the approved FMP.

4.6.9.6 Schedule 3 Item 6 – Details of the past performance (if any) of production wells in the field and a prediction of the future performance of those wells

Provide any monthly production reports for the field. This item is particularly important for a revision to an FMP. A production forecast is required for wells currently under production, or for potential development projects in the field.

4.6.9.7 Schedule 3 Item 7 – The proposed maximum rate of recovery of petroleum from a petroleum pool in the field

The proposed maximum rate of recovery (RoR) from a petroleum pool should take into consideration the extent (volume) of the petroleum pool and its expected lifetime. Further considerations for the management of the petroleum resource include optimising for the maximum long-term recovery of the resource rather than just the quickest recovery. The RoR should be consistent with good oilfield practice.

This maximum rate of recovery may be altered by revising the FMP, with approval of the REC Division, at any stage during the development of the field.

4.6.9.8 Schedule 3 Item 8 – Details of the following:

(a) any aquifers that could be affected by the development of the field
(b) the applicant's proposals for the management of such aquifers, including proposals for baseline monitoring

All potential aquifers within the influence of field development activities need to be identified and plans must be provided for the protection of these aquifers. The basis for aquifer identification and any proposed baseline monitoring should be described. Note that further detail on shallow aquifer monitoring is required in the environment plan (EP); the FMP should be consistent on a high level with the EP. Production activities that may significantly affect regional aquifer pressure should be noted, with a risk mitigation plan to minimise impacts on nearby reservoirs or developments provided.

4.6.9.9 Schedule 3 Item 9 – The project schedule, including the following:

(a) an estimated development timetable for production facilities such as wells, platforms and pipelines
(b) estimated dates for cessation of production and field closure

A timetable for when production facilities will be installed or enhanced must be included. Estimates of reserves, rates of recovery and production forecast should give an estimate of field life. The date of cessation of production is related to item 16 dealing with the closure of the field. The project schedule should be provided in the form of a graph (perhaps a Gantt chart) or table setting out the stages of project development. Note that early cessation of production is a major change (see section 4.6.7) and requires a revision to the FMP.

4.6.9.10 Schedule 3 Item 10 – Details of the applicant's operations or proposals for the following:

(a) the enhanced recovery or recycling of petroleum
(b) the processing, storage or disposal of petroleum
(c) the injection of water or treatment material into an underground formation

Initially, this item will cover details of proposals for facilities and operations to recover and process petroleum. As the field is developed, revisions of the FMP will cover details of changes to operations and facilities that will deal with enhanced recovery. The facilities utilised in the production process should be described including designed and operating capacity. Shape files should be provided showing facility locations and the locations of metering stations.

4.6.9.11 Schedule 3 Item 11 – Arrangements for the following:

(a) monitoring, recording in writing and reporting on the applicant's conduct of pool management
(b) keeping records and other documents about the applicants conduct of pool management

This item pertains to the applicant's plans for monitoring, writing records and reporting on the management of the petroleum pool. Reporting should be in accordance with good oilfield practice and relevant industry codes and standards, including the SPE PRMS. Record keeping is also covered under Part 8 of the RMAR 2015, and includes the requirement to securely retain information and that the information must be reasonably practicable to retrieve.

4.6.9.12 Schedule 3 Item 12 – Details of equipment and procedures used to determine the quantity and composition of petroleum and water

This item defines the equipment used in measuring production and the procedures used to measure quantity and composition of petroleum and water produced. The procedures and the measurement equipment should comply with the relevant Australian or international standard and be accurate and verifiable.

(a) the surface connections and equipment to be used by the applicant

(b) any petroleum production by a well that is from more than one petroleum pool
(c) any petroleum production from a petroleum pool that is through more than one well

In this item,

(a) means each well from which petroleum is recovered shall be provided with such surface connections and equipment as are necessary to prevent the injection of petroleum or water into the well from another well or from production equipment. Shape files for the recovery facilities showing the locations of flowlines and production facilities should be provided (see Schedule 3 Item 10 above).
(b) means that petroleum shall not be recovered simultaneously from more than one pool in a well unless provision is made to maintain separation of petroleum and water recovered from each pool until the petroleum and water pass a point where the quantity and composition of the petroleum and water from each pool is determined.
(c) means that petroleum recovered from different pools and from more than one well shall not be commingled until the petroleum and water pass a point where the quantity and composition of petroleum and water from each well and from each pool in which these wells are completed is determined.

4.6.9.14 Schedule 3 Item 14 – Arrangements for the management of the following:

(a) produced formation material
(b) waste fluid and other waste material produced from wells
(c) treatment material
(d) waste petroleum
(e) refuse from tanks and wells
(f) naturally occurring radioactive materials
(g) geological risk

Produced formation material means produced formation water, produced sand and cuttings. Waste fluid and other waste material means material that was introduced into the well but has been returned to the surface for disposal (e.g. drilling mud, completion fluid, exhausted chemicals). Treatment material means material that was introduced into the well but has been returned to the surface for disposal (e.g. lost circulation material, proppants, chemicals). Waste petroleum is recovered petroleum that cannot be used for any useful purpose, for example, tank slops. Refuse from tanks and wells covers everything from tank residues to general waste on the well sites. NORMs are commonly found as scale in pipework and vessels and must be disposed of appropriately.

The management of waste and other material with consideration of formation pressures and possible leakage must be described, including the sealing nature of faults and other geological features involved. Plans for fluid injection (e.g. produced water disposal) into underground reservoirs, including plans for protecting aquifers and possible risks must be detailed.

Waste fluid and other waste material produced from wells should be dealt with adequately to ensure no harm. The anticipated volume and chemical composition of waste material should be described, along with treatment, alternative use (e.g. as fuel, water used to keep dust down) or disposal plans. Note the requirements in the WMP (Schedule 1, Item 10 and Item 11) regarding waste. The FMP should be consistent with the EP.

4.6.9.15 Schedule 3 Item 15 – Arrangements for the disposal or flaring of any produced petroleum

The arrangements for any disposal, venting or flaring of petroleum during production operations should be presented in detail. The FMP should be consistent with the EP. Under section 144(1)(b) and (c)(i) of the PGERA67 and section 145(1)(b) and (c) of the PSLA82, an application for exemption for royalty payment should be made to DMIRS for petroleum that is used for the purposes of petroleum exploration operations or operations for the recovery of petroleum and for petroleum that is flared or vented in connection with operations for the recovery of petroleum.

4.6.9.16 Schedule 3 Item 16 – Description of the applicant’s plans for closure of the field including plans for decommissioning and rehabilitation

The applicant should demonstrate a capability to understand, execute, and finance decommissioning of the field, any wells in the field, and of any plant or facilities associated with the field. It is expected that more detail will be provided in revisions to the FMP as field closure is approached. Environmental rehabilitation is mainly covered in the EP, so only a brief mention is required in the FMP.

4.6.9.17 Schedule 3 Item 17 – A list of the principal Australian and international standards that apply in relation to the applicant's operations and plant used in connection with those operations

This item requires a list of the particular standards that the title holder is going to apply to their field management, for example, AS2885 series: Pipelines – Gas and Liquid Petroleum.

It is possible that a title holder might apply their own standard. This case would necessarily include more detail than just the name of the standard, as would occur with a commonly known and accepted standard. The standard would then be examined to see if it was equivalent to and consistent with a commonly known and accepted standard.

4.7 RMAR Part 7 — Other matters relating to petroleum or geothermal energy recovery [r. 62 (and r. 63 in the PGER RMAR 2015)]

Part 7 relates to the requirement of a licensee to notify the Minister of any significant events. A significant event means the following under r. 62:

(a) a change in the understanding of the characteristics of the geology or underground formation that may have a significant impact on the optimum long-term recovery of petroleum or geothermal energy
(b) a new or increased risk to the recovery of petroleum or geothermal energy within the licence area
(c) a new or increased risk to the recovery of petroleum or geothermal energy outside the licence area caused by the development of petroleum pools or geothermal resources areas in the licence area
(d) a new or increased risk of activities in the licence area causing effects outside the licence area (for example, aquifer depletion caused by petroleum extraction)
(e) a change to the proposed option for the development of petroleum pools or geothermal resources areas in the licence area, including any tie-in opportunity with nearby licence areas.

Significant events are changes in the understanding of the field or risks associated with recovery, or an event or incident that is not under the direct control of the licensee and was not planned by the licensee.

The licensee is required to use their judgment as to what constitutes a significant event, and in some cases, determining when an event that is occurring becomes significant, and then making the decision to notify the Minister. For example, in the event of aquifer depletion, it may be recognised as happening and that it could potentially be significant. Observation may be necessary over a period of time before the conclusion is made that it is significant (as it is not necessarily unusual, in this event, for an initial drop in pressure to level off as the greater aquifer engages). A licensee would be using their judgment as to when it was concluded as having become significant and when to report it.

It is a requirement under the regulations that the licensee must provide oral notification that a significant event has occurred within two (2) hours of becoming aware of it and written notice within three (3) days. Written notice should be provided to **petroleum.reports@dmirs.wa.gov.au**

Please note: Part 7 r. 62 notification requirement places an emergency status on some 'significant events' which are patently not emergencies and would be more properly dealt with as revisions to management plans. This regulation may be reviewed and amended in the next version of the regulations.

Although Part 7 says notification is required within 2 hours / 3 days, DMIRS expects that a notification in the form of a revision to the FMP (or GERDP) is made, akin to how r. 20 requires a revision to WMPs in certain circumstances (e.g. changes in the understanding of geology and risk, much like what is listed in Part 7).

Written notice should contain all the material facts and circumstances about the significant event that the licensee is aware of or is able to reasonably find out, including when the event occurred or was first detected, and the implications of the event for the reservoir and the optimum long-term recovery of petroleum. It must also include the action the licensee proposes to take in response to the significant event. The licensee may also add other facts they consider relevant.

r. 63 relates to the content of a 'geothermal energy recovery development plan' (GERDP) in Schedule 4 of the PGER RMAR 2015. **Note – Geothermal energy is not legislated under the PSLA82, nor covered in the PSL RMAR 2015.**

4.7.1 Schedule 4 – Geothermal energy recovery development plan

Schedule 4 lists 16 Items required specifically for a GERDP. Reporting of geothermal resources in Australia is guided by the Australian Geothermal Code, which is published by the Australian Geothermal Energy Association (AGEA) and endorsed by the Australian Stock Exchange (ASX). The Australian Geothermal Code is comprised of three documents: The Australian Geothermal Reporting Code (reference), the supporting Glossary of terms (reference) and the Australian geothermal reporting guidelines.

Any submitted GERDP is expected to adhere to the guidelines outlined in the Australian Geothermal Code. Any person reporting under the Australian Geothermal Code must be an approved and registered expert officer under the Code. The requirements may change from time to time, in accord to AGEA rules. A commercially defined geothermal resource area is called a "geothermal field" for brevity below, and is consistent with practices in New Zealand and the United States.

4.7.1.1 Schedule 4 Item 1 – Evidence and data showing the licence area contains geothermal energy resources, including details of the structure, extent, and location of discovered geothermal resource areas.

Evidence and data referred to in Item 1 will include location maps and cross sections through the resource area, which define the 3D extent of the resource. Information provided should refer to geological formations, and the nature of the rocks containing the geothermal resource and any surrounding trapping or containment rocks. Aquifers should be identified, whether as containment rocks of geothermal resources or otherwise. Regional geology including faults, stratigraphy, formation depths, lithology, subsurface mapping, and reservoir parameters should be included. Spatial units must be in metres or kilometres.

4.7.1.2 Schedule 4 Item 2 – Estimates of volume of geothermal energy resources in place and recoverable geothermal energy, including data supporting the estimates.

Geothermal energy in-place is defined in the Australian Geothermal Code, and is essentially expressed as Joules (of heat energy) contained in a defined volume. The volume containing the heat energy needs to be specifically defined, based on drilling, seismic or other geophysical data. Recoverable geothermal energy is usually heat energy contained in geothermal fluids (liquid or gas) that can be recovered at the surface. However, this should not be exclusive, as geothermal energy may be recovered by other processes, such as radiation from hot sources or direct conversion from heat energy into electricity down-hole.

4.7.1.3 Schedule 4 Item 3 – A description of the following:

(a) the possible geothermal energy resources in the licence area
(b) the geothermal licensee's plans (if any) to explore for geothermal resources areas
(c) how many geothermal resources areas of commercial quantity can be incorporated into the development of the licence area

A description of: any further known geothermal energy resources in the licence area that have not yet been evaluated; how and when further exploration is intended to occur to evaluate known geothermal energy resources or to locate any as yet unknown geothermal energy resources; and how geothermal energy resources of commercial quantity can be developed. This may have both the firm intention to develop a known commercial geothermal energy resource and method of developing resources that have potential to be commercial but not yet proven.

4.7.1.4 Schedule 4 Item 4 – A description of the following:

(a) an appropriate strategy for the development of the licence area, management of geothermal resources areas and optimum long-term recovery
(b) any proposed and alternative development scenarios

Item 4 (a) entails a description of the preferred development methodology, including its management over the lifetime of the geothermal energy resource and an estimate of amount of geothermal energy expected to be recovered over the lifetime of the geothermal field. Item 4 (b) requires consideration of any other commercial developments of the geothermal field, if appropriate, and an explanation of why the preferred development strategy has been chosen.

4.7.1.5 Schedule 4 Item 5 – A description of how the geothermal licensee intends to recover geothermal energy over time, including the following information:

(a) the estimated position of wells
(b) the potential timing of workover operations
(c) possible tie-ins

Item 5 may be a sub-set of Item 4. A description of how all geothermal energy resources in the licence area will be incorporated in to the proposed development should include resources that are commercial now, as well as those that may not be commercial on a stand-alone basis, but could be commercial if combined with other resources in the licence area. In the initial stages of a geothermal development it is expected that the estimated position of wells may only be described. However, as the development of the geothermal field progresses, it is expected that tie-ins will revise an approved GERDP.

4.7.1.6 Schedule 4 Item 6 – Details of the past performance (if any) of production wells in the licence area and a prediction of the future performance of those wells

Provide any monthly production reports for the field. A production forecast is required for geothermal wells currently under production, or for potential development projects in the field.

4.7.1.7 Schedule 4 Item 7 – The proposed maximum rate of recovery of geothermal energy from the licence area

The proposed maximum RoR should take into consideration the extent (volume) of the geothermal field, the energy contained in the geothermal field and its expected lifetime. Further considerations of the management of the geothermal reservoir or aquifer should also be considered. This RoR may be altered, with approval of the REC Division, at any stage throughout the development. Any change in the RoR of geothermal energy will revise the GERDP.

4.7.1.8 Schedule 4 Item 8 – Details of the following:

(a) any aquifers that could be affected by the development of the licence area

(b) the geothermal licensee's proposals for the management of such aquifers including proposals for baseline monitoring

Item 8 is a detailed extension of information provided in Schedule 4 Item 1. All potential aquifers within the influence of the development activities need to be identified and plans should be provided for the protection of these aquifers. Item 8 should be addressed in conjunction with the EP and any Department of Water approvals or licences. Baseline monitoring is essential, and all plans for such monitoring must be described in detail.

4.7.1.9 Schedule 4 Item 9 – The project schedule, including an estimated development timetable for production facilities such as wells and pipelines

A timetable for when production facilities will be installed or enhanced must be included. Estimates of reserves and RoR should give an estimate of field life. The date of cessation of production is related to Schedule 4 Item 15 dealing with the closure of the field. The project schedule should be provided in the form of a graph (perhaps a Gantt chart) or table setting out the stages of project development.

4.7.1.10 Schedule 4 Item 10 – Details of the geothermal licensee's operations or proposals for the following:

(a) the enhanced recovery or recycling of produced formation material

(b) the processing, storage or disposal of produced formation material

(c) the injection of water or treatment material into an underground formation

Initially, this item will cover details of proposals for facilities and operations to recover geothermal energy resources. As the field is developed, revisions of the GERDP will cover details of changes to operations and facilities that will deal with enhanced recovery.

4.7.1.11 Schedule 4 Item 11 – Arrangements for the following:

(a) monitoring, recording in writing and reporting on the geothermal licensee's management of geothermal resources areas

(b) keeping records and other documents about the geothermal licensee's management of geothermal resources areas

This item pertains to the applicant's plans for monitoring, writing records and reporting on the management of the geothermal resource. Reporting should be in accordance with the Australian Geothermal Code. Record keeping is also covered under Part 8 of the RMAR 2015, and includes the requirement to securely retain information and that the information must be reasonably practicable to retrieve.

4.7.1.12 Schedule 4 Item 12 – Details of the following:

(a) the surface connections and equipment to be used by the geothermal licensee

(b) any geothermal energy recovery through a well that is from more than one geothermal resources area

(c) any geothermal energy recovery from a geothermal resources area that is through more than one well

In this item,

(a) means each well from which geothermal energy is recovered shall be provided with such surface connections and equipment as are necessary to prevent the injection of water into the well from another well or from production equipment. Shape files showing the locations of flowlines should be provided.

(b) means that geothermal energy shall not be recovered simultaneously from more than one geothermal resource in a well unless provision is made to maintain separation of geothermal energy recovered from each resource until the water passes a point where the quantity of geothermal energy from each geothermal resource is determined.

(c) means that geothermal energy recovered from more than one well shall not be commingled until the water passes a point where the quantity of geothermal energy from each well completed in the geothermal resource area is determined.

4.7.1.13 Schedule 4 Item 13 – Arrangements for the management of the following:

(a) produced formation material
(b) waste fluid and other waste material produced from wells
(c) treatment material
(d) waste heat
(e) refuse from tanks and wells
(f) naturally occurring radioactive materials
(g) geological risk

Produced formation material means produced formation water, produced sand and cuttings. Waste fluid and other waste material means material that was introduced into the well but has been returned to the surface for disposal (e.g. drilling mud, completion fluid, exhausted chemicals). Treatment material means material that was introduced into the well but has been returned to the surface for disposal (e.g. lost circulation material, chemicals). Waste heat is recovered heat energy that cannot be used for any useful purpose. Refuse from tanks and wells covers everything from tank residues to general waste on the well sites. NORMs are commonly found as scale in pipework and vessels and must be disposed of appropriately.

The management of waste and other material with consideration of formation pressures and possible leakage must be described, including the sealing nature of faults and other geological features involved. Plans for any fluid injection (e.g. produced water disposal) into underground reservoirs, including plans for protecting aquifers and possible risks, must be detailed.

Waste fluid and other waste material produced from wells should be dealt with adequately to ensure no harm. The anticipated volume and chemical composition of waste material should be described, along with treatment, alternative use (e.g. as fuel, water used to keep dust down) or disposal plans. Note the requirements in the WMP (Schedule 1, Item 10 and Item 11) regarding waste. The GERDP should be consistent with the EP.

4.7.1.14 Schedule 4 Item 14 – Arrangements for the disposal or flaring of any produced petroleum

This item should in fact refer to the dissipation of geothermal energy in connection with operations for the recovery of geothermal energy, rather than disposal or flaring of produced petroleum. Under section 144 (1)(ba) and (c)(ii), an application for exemption of royalty payment should be made to DMIRS for geothermal energy that is used for the purposes of geothermal energy resources exploration operations or operations for the recovery of geothermal energy, and for geothermal energy that is dissipated in connection with operations for the recovery of geothermal energy.

Should the occasion occur where petroleum is recovered, the title holder should refer the matter to the REC Division of DMIRS. A clause to this effect should be covered in the proposed GERDP. If petroleum is expected, then the treatment of petroleum recovered during the production of geothermal energy should be presented in detail.

4.7.1.15 Schedule 4 Item 15 – A description of the applicant's plans for closure of the geothermal resources areas, including plans for decommissioning and rehabilitation

The applicant should demonstrate a capability to understand and execute decommissioning of the field, any wells in the field, and of any plant or facilities associated with the field. It is expected that more detail will be provided in revisions to the GERDP as field closure is approached. Rehabilitation is mainly covered in the EP, so only a brief mention is required in the GERDP.

4.7.1.16 Schedule 4 Item 16 – A list of the principal Australian and international standards that apply in relation to the geothermal licensee's operations and plant used in connection with those operations

This item requires a list of the particular standards that the title holder is going to apply to their field management, for example, the Australian Geothermal Code.

It is possible that a title holder might apply their own standard. This case would necessarily include more detail than just the name of the standard, as would occur with a commonly known and accepted standard. The standard would then be examined to see if it was equivalent to and consistent with a commonly known and accepted standard.

4.8 RMAR Part 8 – Data management [r. 63 through r. 79 in PSL RMAR 2015 and r. 64 through r. 80 in PGER RMAR 2015]

Important note: Regulation numbers differ by one between the PSL and PGER RMAR 2015 from Part 8 onwards, due to the inclusion of geothermal in r. 63 in the PGER regulations only. For simplicity, regulation numbers from here on will be those of the PGER RMAR 2015.

Similarly, the Schedule numbers differ by one, where the PSL regulations do not contain a Schedule for a geothermal energy recovery development plan, herein, Schedule 4 in the PGER RMAR 2015.

Part 8 of the RMAR 2015 details the format, contents and standards required in the reporting, submission, preparation and preservation of petroleum exploration data. The intent is to ensure that any work conducted has been carried out in compliance with the PGER67 and PSLA82. The regulations require that this information is available and accessible in a suitable format. All reports and data submitted to DMIRS in accordance with the petroleum Acts shall remain confidential until the information is eligible for public release as prescribed in section 112 of the PGERA67 and section 118 of the PSLA82.

Submitted data shall contain information of sufficient standard and detail to substantiate, to the satisfaction of the Minister, the expenditure claimed and the activities undertaken on a petroleum permit, lease, licence, drilling reservation or special prospecting authority as reported to DMIRS. All data submitted should be in metric units.

Data is used by the State Government in support of its geoscience projects; to fulfil its role as a data custodian for the State; to undertake key statutory and regulatory functions, including ensuring well integrity for safety purposes, aquifer protection and the future production of State resources; and to provide data and information to other stakeholders.

The petroleum and geothermal industry use this data to support exploration programs, identify new resource targets or areas for exploration and test exploration models to further the search for petroleum and geothermal resources in the most economical and efficient manner.

These guidelines provide additional information to Parts 8 and 9 and Schedules 5-17 of the RMAR 2015 and specify the format, content and standards required in the submission and preparation of petroleum exploration and production data. The tables for reports and data in this section reference the regulations under Part 9 for release of technical information.

4.8.1 Data administration – the 4 Divisions and 12 Schedules of Part 8

Part 8 contains four Divisions:

Division 1 – Preliminary [r. 64]
Division 2 – Requirements for keeping information [r. 65 – r. 66]
Division 3 – Requirements for collection and retention of cores, cuttings and samples [r. 67 – r. 71]
Division 4 – Requirements for giving reports and samples [r. 72 – r. 80]

Division 1 simply defines the term 'operation' to mean an operation carried out under the authority of an instrument. An instrument in Part 8 means a title [r. 64] therefore a title holder is an instrument holder. In this Part, the term instrument holder is used.

4.8.2 Division 2 – Requirements for keeping information [r. 65 – r. 66]

Division 2 relates to record keeping and the requirements for an instrument holder to keep information, such as accounts, records, or other documents in connection with an operation, secure as well as easily retrievable.

4.8.3 Division 3 – Requirements for collection and retention of cores, cuttings and samples [r. 67 – r. 71]

Division 3 outlines the requirements for the instrument holder to securely retain samples obtained from geoscientific activities, and unless the Minister has authorised otherwise, these samples must remain in Australia [r. 67, r. 68]. Any samples removed from Australia must be returned to Australia within the timeframes listed in r. 69.

Under the regulations, the instrument holder is required to provide a report on the progress of any analysis of a sample that is taking place outside of Australia within 12 months of the authorisation being given for the analysis to be done. The final report on the analysis will be submitted as part of the well completion report. Table 6 outlines the format and media for progress reports and data for petroleum mining samples sent for analysis overseas [r. 70]. Retrieval of cores, cuttings or other samples collected must be reasonably practical [r. 71].

Requests for approval for the export of confidential samples (for example, to carry out an analysis of the sample overseas) are to be directed to **petdata@dmirs.wa.gov.au**

The request should include the following information:

- title number
- well name(s)
- rig release date(s)
- confirmation that the instrument holder, requesting the export approval, was responsible for the drilling of the well
- the current location of the samples
- description and details of the samples
- details of analyses
- if the proposed analyses are destructive
- the name, address and country of the company undertaking the analyses
- confirmation of compliance with Division 4 [r. 72]
- timeframe for returning samples and reporting.

4.8.4 Division 4 – Requirements for giving reports and samples [r. 72 – r. 80]

Division 4 outlines the requirements for the instrument holder to submit reports and samples to the Minister. Content and specifications are to be in accordance with the items in Schedules 5-17. Tables 7-15 found at the end of this chapter provide additional guidance on the submission of reports and data, and reference the confidentiality period for each submission.

It is a requirement that data shall be submitted to DMIRS for the following types of petroleum instruments:

- Exploration Permit (EP, TP)
- Drilling Reservation (DR)
- Retention Lease (R, TR)
- Production Licence (L, TL)
- Special Prospecting Authority (SPA)
- Scientific Investigation (SI)
- Access Authority (AA).

When the following geoscientific activities have been undertaken in the search for hydrocarbons, the data generated that relate to those activities are to be provided to DMIRS:

- well drilling, intervention and testing operations
- geochemical and geophysical surveys (seismic, aeromagnetic, gravity, etc.)
- geophysical reprocessing studies (seismic, aeromagnetic, gravity, etc.).
- geological/geophysical studies, analysis, interpretation

4.8.4.1 Subdivision 1 – Reports about well activities [r. 72 – r. 74]

This Subdivision covers the submission of three types of reports and data about well activities undertaken in a petroleum or geothermal instrument. These are the daily well activity report [r. 72], the final well activity report [r. 73] and the well completion report (WCR) [r. 74].

- The daily well activity reports are the daily reports generated by or for the registered holder for each day when there is an activity on a petroleum or geothermal well.

- Reports are required during drilling and post-drilling activities, and must be submitted on a daily basis. The final well activity report is submitted along with the data within six months of the conclusion of any post-drilling activity.

- The well completion report is submitted within 12 months after a well is drilled. It will include the daily drilling reports.

Content of these reports and data is described in the following PGER RMAR 2015 Schedules:

Schedule 5 – Daily well activity report [r. 72(1)]

Schedule 6 – Final well activity data [r. 73(1)] – if conducted

Schedule 7 – Final well activity report [r. 73(1)] – if conducted

Schedule 8 – Well completion data [r. 74(1)]

Schedule 9 – Well completion report [r. 74(1)]

These are Schedules 4-8 in the PSL RMAR 2015.

Table 7 outlines the submission requirements for well activity reports and data obtained from a drilling activity, including the well completion report. All daily well activity (daily drilling) reports must be submitted by email to **petroleum.reports@dmirs.wa.gov.au**

It is a requirement to submit a report of the daily drilling activity for each day during the drilling of a well. These reports must contain the relevant well identification information, details of the drilling rig, and a summary of the drilling operations carried out during the relevant 24 hour period. These may include:

- depth in metres at the end of the drilling for that period
- size and type of drill bits used
- drilling fluids and additives used
- size and depth of any casing inserted in the well
- results of any deviation surveys
- description of any drill stem tests or other tests carried out
- details of any squeeze cementing or cement plugs carried out
- details of any core or cutting samples taken
- details of any hole problems
- details of leak-off tests.

The daily well activity report has 24 Items under Schedule 5 to be addressed. Some of these will appear in every daily well activity report (i.e. Items 1-4, 6, 7, 14, 15, 19, 22 and 24). The others will apply depending on the activity occurring.

Table 8 outlines the submission requirements for reports and data obtained from well activities carried out post-drilling, such as when a well is re-entered for a workover activity. The daily activity reports should be submitted each day to **petroleum.reports@dmirs.wa.gov.au**. The final well activity report has 29 Items under Schedule 7 to be addressed. The final well activity report is to be submitted to **petdata@dmirs.wa.gov.au**. Reports that are less than 160 MB in size can be submitted using the online submission form in PGR.

The WCR, and the data contained within it, is a key document utilised by a variety of users to develop knowledge of the geology of a region and commercial resource potential. Schedule 9 provides the information and level of detail required in the WCR. The WCR is submitted to the Statutory Exploration and Information Group (SEIG). The data are submitted to various locations depending on what type of data it is (see heading 4.8.4.4).

At a minimum, the WCR must include the following information:

- The type and number of the relevant petroleum or geothermal tenure.
- The name and postal address of the title holder of the well or bore.
- The identifying name and number of the well or bore.
- Total Authorisation For Expenditure (AFE) cost of the well.
- The type of well, e.g. petroleum/ geothermal, exploration, appraisal or development.
- Location of the well or bore (longitude and latitude, eastings and northings with any map projection and referenced coordinate system), the name of the basin and any sub-basin, map sheet and graticular block; and the closest seismic lines (in-line and crossline if a 3D seismic survey has been carried out in the drilled area).
- The ground level and kelly bushing or rotary table level in metres for the well or bore.
- The total depth in metres of the well or bore (usually driller's depth and logger's depth) and the true vertical depth of the well (if surveyed during drilling).
- The date drilling commenced (spud date). Note that the date of rig mobilisation to site and rig set up is not the spud date.
- The date total depth was reached (TD date).
- The rig release date for the well or bore.
- Details of the drilling rig including the name of the drilling contractor; rig name, make and model; number and type of drill bits; drilling fluids and chemicals used to drill the well or bore.
- Status of the well or bore on the rig release date (e.g. producing, plugged and abandoned, cased and/or suspended).
- Stratigraphic intervals and formation tops/horizons intersected in the well or bore in measured depth and true vertical depth, with reference to the datum used (e.g. mRT, mKB, mSS and/or mAHD), with comparison of prognosed and actual depths, where applicable.
- Casing summary, including grade, diameter and length, perforated/non-perforated.
- A summary of the log types and intervals run in the well or bore.
- A detailed summary of coring intervals (conventional and sidewall) and diameters of core recovered.
- A summary of samples (e.g. drill cuttings and cores) taken.
- A summary of analyses carried out, in situ data (e.g. pressure and temperature) and post drilling analyses (e.g. routine core analysis and special core analysis); processed and any interpreted wireline logging data; reservoir quality data in the form of petrographic data: SEM, XRD, mineralogy; vitrinite reflectance, TOC; geomechanical/rock strength testing, formation fluid analysis, etc.
- Schematics to include: time-depth curve, surveyed path of the well (azimuth and inclination), well as designed and well as constructed. The latter should show well integrity considerations, with any plug and abandon or suspension or monitoring station detail.
- Logs to include lithological descriptions, stratigraphic log, mud log, composite log, wireline logs.
- All reports and analytical reports and data to be included as appendices to the WCR.

Please note that this is not intended to represent an exhaustive list of possible inclusions in the WCR and where other pertinent information or data are available, these should be included. Table 7 specifically outlines the information and data submission requirements for the WCR.

Throughout the WCR it needs to be clear what common depth datums are recorded (i.e. Ground Level (GL), Rotary Table (RT), Kelly Bushing (KB), metres below sea level (SS) or metres relative to Australian height datum (AHD)) and whether it is the measured depth (MD) or true vertical depth (TVD). This should be consistent throughout the report, in each table; in each figure and within the text. Alternatively, the inclusion of a statement such as, "All depths are Measured Depth relative to Rotary Table (RT) unless otherwise stated" can be made but the submitting company must ensure that this is indeed the case.

4.8.4.2 Subdivision 2 – Reports about surveys [r. 75–r. 78]

This Subdivision covers four types of reports (and associated data) on surveys undertaken in a petroleum or geothermal instrument. These are the weekly survey report [r. 75], the survey acquisition report and data [r. 76], the survey processing report and data [r. 77] and the survey interpretation report and data [r. 78]. Survey types include 2D seismic, 3D seismic or other (e.g. gravity, aeromagnetic, geochemical). Digital data means seismic field data, processed seismic data, navigation data, velocities, etc.

Schedule 10 – Weekly survey report [r. 75(1)]
Schedule 11 – Survey acquisition data [r. 76(1)]
Division 1 – Seismic surveys
Division 2 – Other surveys
Schedule 12 – Survey acquisition report [r. 76(1)]
Schedule 13 – Survey processed data [r. 77(1)]
Division 1 – 2D seismic surveys
Division 2 – 3D seismic surveys
Division 3 – Other surveys
Schedule 14 – Survey processing report [r. 77(1)]
Schedule 15 – Interpretative survey data [r. 78(1)]
Schedule 16 – Survey interpretation report [r. 78(1)]

The schedules outline the information required in each type of survey. A weekly survey report is required for each survey type. Each report must be submitted to **petroleum.reports@dmirs.wa.gov.au**

Tables 9 through 20 provide more guidance on the information listed in the schedules. The information has been grouped under 2D seismic, 3D seismic and other surveys so that the reader may find all the information about a particular survey type in one place.

All reports and digital data (i.e. field and processed data), other than the weekly survey report, shall be sent, accompanied by a Letter of Transmittal, to:

Postal Address
Statutory Exploration and Information Group – Petroleum
Geological Survey and Resource Strategy Division
Department of Mines, Industry Regulation and Safety
Locked Bag 100
East Perth WA 6892

Physical/Courier Address
Statutory Exploration and Information Group – Petroleum
Geological Survey and Resource Strategy Division
Department of Mines, Industry Regulation and Safety
1st Floor North, 100 Plain Street
EAST PERTH WA 6004

4.8.4.3 Subdivision 3 – Production reports [r. 79]

Monthly production reports, which include the information described in Schedule 17 (Division 1 for petroleum licensee and Division 2 for geothermal licensee) are to be submitted to **petroleum.reports@dmirs.wa.gov.au**. Table 19 summarises the submission information and confidentiality period for production reporting and Schedule 17 provides the requirements for production reports. Contact DMIRS for an Excel template prepared for the submission of production data.

4.8.4.4 Subdivision 4 – Cores, cuttings and samples [r .80]

Under r. 80, an instrument holder is required by the RMAR 2015 to give the specified quantity of cores, cuttings or samples within a specified timeframe, as outlined in the table in the regulation. Samples recovered during exploration work programs are to be submitted to either DMIRS or Geoscience Australia, depending on the sample type, for storage. All fluid samples (Items 4 and 5 in the table under r. 80(1)) must be submitted to Geoscience Australia. All other samples (Items 1, 2, 3, 6, and 7 in the table under r. 80(1)) must be submitted to DMIRS.

Table 20 summarises the requirements for the submission of 'petroleum mining samples', that is, cores, cuttings and fluid samples, as well as the relevant confidentiality period (under Part 9, r. 96).

Note that the period for dealing with the remainder of a full hole conventional core is expected to be submitted as soon as practicable after the title holder has completed tests on the core, rather than after the expiry of the instrument as mentioned in the published regulations.

Similarly the period for the submission of gaseous hydrocarbon samples is expected to be as soon as practicable after the completion of the test during which the sample was collected, rather than after the expiry of the instrument as mentioned in the published regulations.

Cores, sidewall cores and cuttings from well drilling operations are to be submitted to:

Core Librarian
Department of Mines, Industry Regulation and Safety
37 Harris Street
CARLISLE WA 6101

Fluid samples must be taken from all wireline, drill stem or production tests, and must be representative of the reservoir fluid. Outlined below are the requirements for representative liquid and gaseous hydrocarbon samples.

A representative hydrocarbon sample must be taken from:

- the test tool for Repeat Formation Tester (RFT), Modular Formation Dynamics Tester (MDT) or equivalent
- the flow lines for Drill Stem Test (DST) and Production Test (PT).

The hydrocarbon sample must be representative of the reservoir and is not the remaining fraction left in the cylinder after (PVT or other) tests have been performed.

If multiple samples are collected from the same geological zone then the minimum requirement is for the submission of one representative sample, however, if sufficient material is collected then submission of additional samples is encouraged. If liquid hydrocarbons are recovered, then the gas and liquid hydrocarbon pair from the same reservoir unit should be submitted.

For gaseous hydrocarbons (Item 4), samples must be stored in appropriate stainless steel gas cylinders that are new, clean and evacuated prior to filling. A total sample volume of 300 cc must be submitted as either one cylinder of 300 cc internal volume or two cylinders of 150 cc internal volume. The cylinders must be equipped with at least one appropriate on/off valve.

For RFT, MDT samples (or equivalent), the sample should be submitted at reservoir pressure where possible.

NOTE: GA's laboratory typically uses cylinders rated to 5000 psi, these can have 3000 psi valves or 5000 psi valves attached (according to requirement). This means that they would be able to hold a gas sample of about 2500 psi and 4500 psi, respectively.

For DST and PT surface samples, the sample should be submitted at the sampling pressure.

NOTE: GA's laboratory typically uses cylinders rated to 1800 psi.

The gas cylinders typically use a female ¼" NPT swage lock gas tight fitting, therefore a male ¼" NPT swage lock gas tight adaptor is used to connect to the parent cylinder.

For liquid hydrocarbons (Item 5) collected from the separator and stock tank, both types of sample should be submitted. Depending on the analysis that is to be performed at a later date, these different sample types may be used for several purposes:

- Separator samples contain more light ends than stock tank samples so are more representative of the overall fluid composition.
- For gas/condensate analysis it is better to provide additional cylinders of gas so the liquids can be recovered in the laboratory.
- Both separator liquid and stock tank samples are useful for biomarker analyses, when the light ends are removed in the laboratory in order to concentrate the heavier molecules.

If liquid hydrocarbons are recovered from a DST or PT, 0.5–1L of the liquid hydrocarbons must be submitted at atmospheric pressure in a 1L screw top Pyrex/Schott glass bottle.

The sample container (gas cylinder and/or glass bottle) must be labelled clearly (labels should not be hand written). The information to be supplied is as follows:

- well name
- basin name
- date and time of sampling
- test type RFT/MDT (or equivalent)
- depth of RFT/MDT (or equivalent) sample
- depth of perforated interval for DST and PT sample
- reservoir pressure
- cylinder pressure
- pressure conditions under which the sample was collected, i.e. wellhead, atmospheric, etc.
- conditions under which the sample was collected, i.e. dynamic or static, before or after the separator, etc.
- temperature of formation or surface, as appropriate
- weight of evacuated cylinder/valve(s)
- weight of full cylinder/valve(s).

The title holder is responsible to ensure that the sample container is suitable for both safe transport and storage at the pressure of its contents. All occupational health and safety guidelines must be followed. Dangerous goods information must be supplied with the consignment.

A transmittal document must accompany the sample container, detailing the service company and petroleum company contact details and sample information. The well and test data must be supplied with the transmittal. A return 'receipt of goods sheet' must be included.

Gaseous and fluid hydrocarbon samples (Table 20) from well and field testing operations, are to be stored in an API approved safety container and submitted, on completion of the tests, to:

Data Repository Manager
Geoscience Australia
Cnr Jerrabomberra Ave and Hindmarsh Drive
SYMONSTON ACT 2609

The data repository manager can be contacted for further information on:

Phone 02 6249 9222
Fax 02 6249 9903
E-mail **ausgeodata@ga.gov.au**

4.8.5 Media for data submission

The following points apply to all submissions:

- Hardcopies of reports and data are not to be submitted. If no format is indicated in the regulations, an electronic format appropriate to the report or data is to be used. For example, PDF for a report, such as a well completion report.
- PDF files are to be security free.
- Submissions can be made via the DMIRS Ad Hoc File Transfer (AHT) site.

The media used will be dependent on either or both the volume and format of the data submitted and companies are to use their discretion to use the media that will best reduce the number of media being submitted. Schedule 8 lists the standard media and formats for the types of data to be submitted.

Email submissions should only be directed to **petdata@dmirs.wa.gov.au** or **petroleum.reports@dmirs.wa.gov.au**. The department will accept the following media for delivery of reports and data:

- E-mail attachment (where total attachment file size not does exceed 10 MB).
- CD-ROM – full size, no multisession, read only.
- DVD-ROM – full size, no multisession, read only.
- Portable Hard drive, non-returnable – security (password) free.
- USB flash drive, non-returnable – security (password) free.
- Industry standard 3592 tape cartridges for large volume datasets, e.g. seismic field data.
- LTO cartridge

Submissions can be made via DMIRS FTP site by request. Any queries can be directed to **petdata@dmirs.wa.gov.au**

All optical and drive/flash media must be individually labelled with company name, title number(s), activity name, data type, date tape created, and disc or drive number; for example 1/5).

All tape cartridges containing seismic data must be individually labelled with the company name, title number(s), activity name, data type (field, stack, migration, PSTM, AVO etc.), data format (SEGD, SEGY, etc.), line numbers (2D only), date tape created and tape number (1/5, 2/5, etc.).

A list of all files submitted is to be included on a separate document with the data submission.

4.8.6 Recommended archive practice for digital data

The National Archives of Australia (NAA) has developed a voluntary code of best practice for the storage of government records and provides a tool to support and improve the management of those records.

It is recommended that an instrument holder adopts the Standards and associated Guidelines in relation to data management. The NAA reviews and updates these documents, therefore, it is important that instrument holders ensure that the most up to date version is being referred to. The link below is to the NAA website, which contains the "Standard for the Physical Storage of Commonwealth Records" and the "Storing to the Standard: Guidelines for Implementing the Standard for the Physical Storage of Commonwealth Records", along with other publications to help you manage your records: **https://www.naa.gov.au**

Table 6. Petroleum mining sample analysis overseas [r. 70]

Release of the petroleum well data and petroleum mining samples [r. 91(5)]

The data are released as part of the well completion report release (see below) or according to the conditions of borrowing the sample(s) from the Geological Survey and Resource Strategy Division of DMIRS.

- For an instrument still in force: **2 years** from rig release.
- For an instrument that has expired, or has been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.

Report/Data/Samples	Format/Media	Submission Date	Remarks
Export core or cutting progress report of the analysis [r. 70]	PDF CD-ROM/DVD or portable hard drive	The end of each subsequent 12 month period from the authorisation date	Analysis report and data are to be submitted as part of the well completion report (where available); or separately where the analysis report becomes available after the well completion report has been submitted
Data from investigation, analysis, etc. of cuttings or core plugs	ASCII, XLS CD-ROM/DVD or portable hard drive	12 months after sampling or borrowing material	As a tab delimited ASCII file with metadata included and attached to the analysis report Refer to conditions of borrowing

Table 7. Well activity reports and data – for a drilling activity [r. 72, r. 74]

Release of the petroleum and geothermal energy well data and petroleum and geothermal energy mining samples [r. 91(5)]

- For an instrument still in force: 2 years from rig release.
- For an instrument that has expired, or has been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.

Release of interpretative disclosable information, e.g. well completion report and data under r. 74(1) [r. 92(1)]

- For well information: **2 years** after the operation to which the information relates was substantially completed (i.e. rig release).
- For any other information (see Table 21): **5 years** after the operation to which the information relates was substantially completed.

Report/Data/Samples	Format/Media	Submission Date	Remarks
Daily well activity report [r. 72]	PDF	Midday on the day after the day to which the report relates	This is the equivalent of the daily drilling report Refer to **Schedule 5** for information required in this report
Well completion report [r. 74]	PDF	12 months after the rig release date	Refer to **Schedule 9** for information required in this report Daily activity (drilling) reports are to be included in the well completion report Image files and logs included in report must be submitted as separate files See notes on petrophysical, geochemical or other sample analyses in this table Hard copies are not to be submitted

Table 7. Well activity reports and data – for a drilling activity [r. 72, r. 74] (continued)

Report/Data/Samples	Format/Media	Submission Date	Remarks
Well completion data			**Schedule 8 [r. 74(1)]**
Raw data, edited field data and processed data for all wireline	DLIS or LAS CD-ROM/DVD or portable hard drive	12 months after the rig release date	Include a verification listing of the data supplied. The data shall include full header information Includes raw well data for all tests conducted
Wireline Log Display	PDF, TIFF CD-ROM/DVD or portable hard drive	12 months after the rig release date	Continuous page at a readable scale
Edited field data and processed data for all MWD or LWD log holes	DLIS or LAS CD-ROM, DVD or portable hard drive	12 months after the rig release date	Include a verification listing of the data supplied. The data shall include full header information Includes raw well data for all tests conducted
MWD or LWD Log Display	PDF, TIFF CD-ROM, DVD or portable hard drive	12 months after the rig release date	Continuous page at a readable scale
Mudlogging data	ASCII or LAS CD-ROM, DVD or portable hard drive	12 months after the rig release date	Include a header giving field names, curve names and units of measure
Mudlog display	TIFF or PDF CD-ROM, DVD or portable hard drive	12 months after the rig release date	Continuous page at a readable scale
Edited field and processed data for borehole deviation surveys	ASCII, LAS, or XLS CD-ROM/DVD or portable hard	12 months after the rig release date	The data shall include full header information
If generated, data from velocity surveys including: • raw data; • processed data; and • checkshot and time/depth analysis	DLIS or SEG-Y for raw data and processed data DLIS, SEG-Y or ASCII for checkshot data CD-ROM, DVD or portable hard drive	12 months after the rig release date	To include verification header file
Velocity survey displays	TIFF, JPEG or PDF CD-ROM, DVD or portable hard drive	12 months after the rig release date [r. 74(2)(b)]	

Table 7. Well activity reports and data – for a drilling activity [r. 72, r. 74] (continued)

Report/Data/Samples	Format/Media	Submission Date	Remarks
Interpretative log analysis	DLIS, ASCII, LAS or XLS CD-ROM, DVD or portable hard drive	12 months after the rig release date [r. 74(2)(b)]	
Petrophysical, geochemical or other sample analyses	ASCII or XLS CD-ROM, DVD or portable hard drive	12 months after the rig release date [r. 74(2)(b)]	As a tab delimited ASCII file with metadata included
Composite well log	TIFF, JPEG or PDF CD-ROM, DVD or portable hard drive	12 months after the rig release date [r. 74(2)(b)]	As part of the well completion report
Photography of the core and sidewall core, in both natural and UV light	JPEG or TIFF CD-ROM, DVD or portable hard drive	12 months after the rig release date [r. 74(2)(b)]	UV light photography to be done and submitted in fluorescent sections only Provide minimum 300 dpi image in 24-bit colour. High-resolution images able to be magnified (zoom in) without pixilation. If not in specified format, a reader program to be provided These are requested separately to images included in other reports so that original quality can be preserved Where possible, raw imagery to also be provided when submitting core samples

Table 8. Well activity reports and data – for a post-drilling activity (e.g. workover) [r. 72, r. 73]

Release of the petroleum well data and petroleum mining samples [r. 91(5)]

- For an instrument still in force: **2 years** from rig release.
- For an instrument that has expired, or has been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.

Release of interpretative disclosable information, e.g. final well activity report and data under r. 73(1) [r. 92(1)]

- For well information: **2 years** after the operation to which the information relates was substantially completed (i.e. rig release).
- For any other information (see Table 21): **5 years** after the operation to which the information relates was substantially completed.

Report/Data/Samples	Format/Media	Submission Date	Remarks
Daily well activity report [r. 72]	PDF	Midday on the day after the day to which the report relates	A daily report is required for post-drilling activities. Refer to **Schedule 5** for information required in this report
Final well activity report [r. 73]	PDF CD-ROM/DVD or portable hard drive	6 months after the completion date for the well activity	Refer to **Schedule 7** for information required in this report
Final well activity data (if a post well activity has occurred)			**Schedule 6 [r. 73(1)]**
Raw data, edited field data and processed data for all wireline logs *(If generated)*	DLIS or LAS CD-ROM/DVD or portable hard drive	6 months after the completion date for the well activity [r. 73(2)(b)]	Include a verification listing of the data supplied. The data shall include full header information Includes raw well data for all tests conducted
Wireline Log Display *(If generated)*	PDF or TIFF CD-ROM/DVD or portable hard drive	6 months after the completion date for the well activity [r. 73(2)(b)]	Continuous page at a readable scale
Edited field data and processed data for all MWD or LWD logs *(If generated)*	DLIS or LAS CD-ROM, DVD or portable hard drive.	6 months after the completion date for the well activity [(r. 73(2)(b)]	Include a verification listing of the data supplied. The data shall include full header information Includes raw well data for all tests conducted
MWD or LWD Log Display *(If generated)*	PDF or TIFF CD-ROM, DVD or portable hard drive	6 months after the completion date for the well activity [(r. 73(2)(b)]	Continuous page at a readable scale
Edited field and processed data for borehole deviation surveys *(If generated)*	ASCII, LAS, or XLS CD-ROM/DVD or portable hard	6 months after the completion date for the well activity [(r. 73(2)(b)]	The data shall include full header information
Petrophysical, geochemical or other sample analyses *(If generated)*	ASCII or XLS CD-ROM, DVD or portable hard drive	6 months after the completion date for the well activity [(r. 73(2)(b)]	As a tab delimited ASCII file with metadata included

Table 9. 2D seismic survey acquisition reports and data (field data) [r. 75, r. 76]

Release of basic disclosable information [r. 91(2)]:

- A survey that collected exclusive data and the instrument is still in force: **3 years** after the acquisition.
- A survey that collected exclusive data and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.
- A survey that collected 2D seismic data as non-exclusive data: the day **15 years** after the acquisition of the data completed.

Report/Data	Format/Media	Submission Date	Remarks
Weekly survey report [r. 75]	PDF Email	As soon as practicable after the end of each week of the survey	Refer to **Schedule 10** for information required in this report
Survey acquisition report [r. 76]	PDF CD-ROM, DVD or portable hard drive	18 months after the acquisition	Refer to **Schedule 12** for information required in this report Weekly survey reports are to be included If surveys cross into Commonwealth waters or other States' areas, contact the Petroleum Data Manager to discuss data submission Clearly identify the seismic line prefix and line numbers Where possible, the survey acquisition report should be submitted at the same time as the field data
2D survey acquisition data			**Schedule 11 [r. 76(1)]**
Final processed navigation data	UKOOA (P1/90 or later) CD-ROM, DVD, portable hard drive	18 months after the acquisition	Including source and receiver coordinates. **See Appendix 1 for P1/90 example**
Seismic field data	SEG Standard 3592 cartridge or LTO	18 months after the acquisition	Must include observers' logs Where possible, the survey acquisition report should be submitted at the same time as the field data
Observers' logs and associated support data	PDF, XLS CD-ROM, DVD or portable hard drive	18 months after the acquisition	Observers' logs should be submitted concurrently with field data
Uphole data (onshore)	ASCII CD-ROM, DVD or portable hard drive	18 months after the acquisition	Includes line number, shotpoint and time depth pairs for each uphole

Table 10. 2D seismic survey processing reports and data [r. 77]

Report/Data	Format/Media	Submission Date	Remarks
Survey processing report [r. 77]	PDF CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	Refer to **Schedule 14** for information required in this report To include sample print out of SEG-Y header
2D seismic processed data			**Schedule 13, Division 1**
Raw and final stacked data, including near/mid/far angle stacks, if generated	SEG-Y DVD, portable hard drive, LTO cartridge or 3592 cartridge	24 months after the day on which the acquisition of the data is completed	Includes fully annotated EBCDIC header
Raw and final migrated data, including: • near/mid/far angle stacks • PSTM • PSDM if generated	SEG-Y DVD, portable hard drive or 3592 cartridge	24 months after the day on which the acquisition of the data is completed	Includes fully annotated EBCDIC header
Final processed navigation, elevation and bathymetry data	UKOOA (P1/90 or later) CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	
Shot point to common depth point	ASCII CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	
Fully annotated image of final processed migrated data (onshore)	TIFF CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	The image must have a vertical scale of not less than 5 cm/sec
Data for both stacking and migration velocities, including: • line number • shot point • time versus root mean square (RMS) pairs	ASCII CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	

Table 11. 3D seismic survey acquisition reports and data (i.e. field data) [r. 75, r. 76]

Release of basic disclosable information (basic data) [r. 91(2)]:

- A survey that collected 3D exclusive data and the instrument is still in force: **3 years** from the completion of acquisition.
- A survey that collected exclusive data and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation, revocation or termination.
- A survey that collected 3D seismic data as non-exclusive data: the day **15 years** after the acquisition of the data is completed.

Report/Data	Format/Media	Submission Date	Remarks
Weekly survey report [r. 75]	PDF Email	As soon as practicable (but within 24 hours) after the end of each week of the survey	Refer to **Schedule 10** for information required in this report
Survey acquisition report [r. 76]	PDF CD-ROM, DVD or portable hard drive	18 months after the acquisition	Refer to **Schedule 12** for information required in this report Weekly survey reports are to be included If surveys cross into Commonwealth waters or other States' areas, contact the Petroleum Data Manager to discuss data submission Clearly identify the seismic line prefix and line numbers Where possible, the survey acquisition report should be submitted at the same time as the field data
3D survey acquisition data			**Schedule 11 [r. 76(1)]**
Final processed navigation data	UKOOA (P1/90 or later) CD-ROM, DVD or portable hard drive	18 months after the acquisition	Include source and receiver coordinates **See Appendix 2 for example of the requirements for 3D seismic data**
Seismic field data	SEG Standard 3592 cartridge or LTO	18 months after the acquisition	Must include observers' logs Where possible, the survey acquisition report should be submitted at the same time as the field data
Observers' logs and associated support data	PDF, XLS CD-ROM, DVD or portable hard drive	18 months after the acquisition	Observers' logs should be submitted concurrently with field data
Uphole data (onshore)	ASCII CD-ROM, DVD or portable hard drive	18 months after the acquisition	Includes line number, shotpoint and time depth pairs for each uphole

Table 12. 3D seismic survey processing reports and data [r. 77]

Release of basic disclosable information (basic data) [r. 91(2)]:

- A survey that collected 3D exclusive data and the instrument is still in force: **3 years** from the completion of acquisition.
- A survey that collected exclusive data and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation, revocation or termination.
- A survey that collected 3D seismic data as non-exclusive data: the day **15 years** after the acquisition of the data is completed.

Report/Data	Format/Media	Submission Date	Remarks
Survey processing report [r. 77]	PDF CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	Refer to **Schedule 14** for information required in this report Include sample print out of SEG-Y, EBCDIC header, 3D grid definition details used for loading SEG-Y into interpretation work stations **See Appendix 2 (3D seismic data) for example**
3D processed data [r. 77]			**Schedule 13, Division 2**
Raw and final stacked data, including near/mid/far angle stacks, if generated	SEG-Y DVD, portable hard drive, LTO cartridge or 3592 cartridge	24 months after the day on which the acquisition of the data is completed	Includes fully annotated EBCDIC header
Raw and final migrated data, including (if generated): • pre-stack time migration (PSTM) • pre-stack depth migration (PSDM) • near/mid/far angle stacks	SEG-Y DVD, portable hard drive, LTO cartridge or 3592 cartridge	24 months after the day on which the acquisition of the data is completed	Includes fully annotated EBCDIC header
Final processed navigation, elevation and bathymetry data	UKOOA (P1/90 or later) CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	All associated data sufficient to re-process seismic data including shot and receiver coordinates **See Appendix 2 for example of the requirements for 3D seismic data**
Final navigation data: (a) final processed (grid) bin coordinates (b) polygonal position data (outline of the full fold area)	UKOOA (P6/98 or later) CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	UKOOA 3D binning grids *(See Appendix 3)* Listing major inflection points of a polygon describing the location of the survey providing survey name, polygon point, in-line/crossline nomenclature, latitude and longitude. (P6/98 format) **(See Appendix 4)** In (a), 'grid 'coordinates refer to bin centre coordinates

Table 12. 3D seismic survey processing reports and data [r. 77] (continued)

Report/Data	Format/Media	Submission Date	Remarks
Data for both stacking and migration velocities, including: (a) bin number (b) time versus root mean square (RMS) pairs	ASCII CD-ROM, DVD or portable hard drive	24 months after the day on which the acquisition of the data is completed	ASCII western format Including bin number and time versus RMS velocity pair for both stacked and migrated velocities In (a), in-line/crossline or bin/track and x/y navigation values are required In (b), PSTM and PSDM should include INT, Epsilon or Delta values where appropriate
2D data subset, if production is required as a condition of the grant of a title	SEG-Y CD-ROM, DVD, portable hard drive or 3592 cartridge	24 months after the day on which the acquisition of the data is completed	Relates to non-exclusive surveys Final migrated data Referred to as "seismic extracted data grid" – 5 km x 5 km

Table 13. Interpretative report and data for 2D and 3D seismic surveys [r. 78]

Release of interpretative disclosable information (interpretative data) [r. 92(4)]:

- Items under Schedule 15 and 16 – releasable after **5 years** from the date of completion of acquisition.

Report/Data	Format/Media	Submission Date	Remarks
Survey interpretation report [r. 78]	PDF CD-ROM, DVD or portable hard drive	30 months after the day that the acquisition of the data is completed, unless authorised by the Minister for another period	Not required if the survey is non-exclusive
Interpretative survey data [r. 78]			**Schedules 15**
Digital images of interpretation maps	Geo-referenced TIFF or PDF CD-ROM, DVD or portable hard drive	30 months after the day that the acquisition of the data is completed, unless authorised by the Minister for another period	These include TWT and depth structure maps at key horizons and representative sections showing seismic horizon picks Not required if the survey is non-exclusive

Table 14. Reprocessed seismic data [r. 77] (undertaken as part of work program)

Release of basic disclosable information [r. 91(3)]

- Reports and data are released **3 years** after the last day of the year of the term of the instrument during which the reprocessing was done.

Report/Data	Format/Media	Submission Date	Remarks
Raw stacked data 2D and 3D, near/mid/far sub-stacks – if generated	SEG-Y 3592 cartridge LTO cartridge CD-ROM/DVD or portable hard drive	24 months after the day on which the reprocessing of the data is completed	If the data reprocessed is licensed non-exclusive data that is still confidential, the data will not be made publicly available until the original survey is publicly available The original survey names and line prefixes are to be clearly identified Clearly identify the reprocessing project name, using the same project name for all submissions
Raw and final migrated data including: • PSDM / PSTM (2D and 3D) • near/mid/far sub-stacks – if generated	SEG-Y 3592 cartridge LTO cartridge CD-ROM/DVD or portable hard drive	24 months after the day on which the reprocessing of the data is completed	
Final processed (grid) bin coordinates for 3D seismic survey	UKOOA CD-ROM/DVD or portable hard drive	24 months after the day on which the reprocessing of the data is completed	To be completed using UKOOA (P6/98 or later)
Polygonal positions for 3D data (Full Fold Outline)	UKOOA CD-ROM/DVD or portable hard drive	24 months after the day on which the reprocessing of the data is completed	Listing major inflection points of a polygon describing the location of the survey providing survey name, polygon point, in-line/crossline nomenclature, latitude and longitude (P6/98 format)
Velocity data	ASCII CD-ROM/DVD or portable hard drive	24 months after the day on which the reprocessing of the data is completed	Include line number, shotpoint, time versus RMS pairs for both stacking and migration velocities
Final report (Reprocessing)	PDF CD-ROM/DVD or portable hard drive	24 months after the day on which the reprocessing of the data is completed	The original survey names and line prefixes are to be clearly identified If the report related to the reprocessing of licensed non-exclusive survey data is still confidential, the report will not be made publicly available until the original survey is publicly available Clearly identify the reprocessing project name, using the same project name for all submissions

Table 14. Reprocessed seismic data [r. 77] (undertaken as part of work program) (continued)

Report/Data	Format/Media	Submission Date	Remarks
Final report (Interpretative)	PDF CD-ROM/DVD or portable hard drive	30 months after the day on which the reprocessing of the data is completed	Geo-referenced TIFF to include TWT and depth structure maps at key horizons and representative sections showing seismic horizon picks
Digital images of interpretation maps	TIFF or PDF CD-ROM/DVD or portable hard drive	30 months after the day on which the reprocessing of the data is completed	These include TWT and depth structure maps at key horizons and representative sections showing seismic horizon picks as geo-referenced TIFF or PDF images

Table 15. Weekly survey report for any other type of survey [r. 75]

Release of basic disclosable information [r. 91(4)]:

- A survey that collected exclusive data and the instrument is still in force: **3 years** from the completion of acquisition.
- A survey that collected data and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.
- A survey that collected data as non-exclusive data (under a Special Prospecting Authority or Access Authority): the day **15 years** after the acquisition of the data was completed.

Report/Data	Format/Media	Submission Date	Remarks
Weekly survey report [r. 75] For gravity, magnetic and all other geophysical or geological survey data	PDF Email	As soon as practicable after the end of each week of the survey	Please format the email subject line by – Titleholder: Survey name: Weekly survey report number For example: Woodside: Bull Aeromagnetic Survey: WSR3 Refer to acquisition report regarding public release

Table 16. Acquisition report and data for any other type of survey [r. 76]

Release of basic disclosable information [r. 91(4)]:

- A survey that collected exclusive data and the instrument is still in force: **3 years** from the completion of acquisition.
- A survey that collected data and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.
- A survey that collected data as non-exclusive data (under a Special Prospecting Authority or Access Authority): the day **15 years** after the acquisition of the data was completed.

Report/Data	Format/Media	Submission Date	Remarks
Field data	ASCII CD-ROM, DVD, portable hard drive, 3592, LTO	18 months after the day that the acquisition of the data is completed	Aeromagnetic located field data: Must include descriptive headers, flight number, line number, date and time, fiducial, raw magnetic reading, processed magnetic reading, radar and GPS or barometric altimeter, and base station reading. All coordinate data must include clearly stated datum, spheroid and map projection, and transformation parameters if not in the same coordinate system as was acquired in the field Gravity field data: Include raw loop data, raw elevations plus measurement times and dates. All coordinate data must include clearly stated datum, spheroid and map projection, with clearly stated transformation parameters if not in the same coordinate system as was acquired in the field All elevation values must be AHD Altimeter, storm monitor, etc. (aeromagnetic only): one copy of diurnal records and altimeter records in an appropriate format Other types of surveys (for example, CSEM): submission and format details to be negotiated
Field support data and navigation data	ASCII CD-ROM, DVD or portable hard drive	18 months after the day that the acquisition of the data is completed	
Survey acquisition report	PDF CD-ROM, DVD or portable hard drive	18 months after the day that the acquisition of the data is completed.	Weekly survey reports are to be included Instrument holders are to submit only data acquired in Australian waters, which will be released in accordance with Part 8 of the RMAR. Reports pertaining to surveys with data acquisition in Australian and international waters will be accepted and released in accordance with Part 8 of the RMAR Must include location map and flight line map if applicable. • Aeromagnetic surveys: Including aircraft and survey equipment details and specifications, flight line directions and terrain clearance, line spacing, total line kilometres • Gravity surveys: Including meter type, scale factor for meter. Data must be tied to an Isogal station in the Australian Fundamental Gravity Network

Table 17. Processed Reports and Data [r. 77(1)(c)]

Release of basic disclosable information [r. 91(2)]:

- A survey that collected exclusive data and the instrument is still in force: **3 years** from the acquisition.
- A survey that collected exclusive data and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation, revocation or termination.
- A survey that collected 2D seismic data as non-exclusive data: the day **15 years** after the acquisition of the data is completed.

Report/Data	Format/Media	Submission Date	Remarks
Survey Processing Report	PDF CD-ROM, DVD or portable hard drive	24 months after the day that the acquisition of the data is completed	Processing report must include company details and processing parameters
Final processed data	ASCII or ASEGGDF2 CD-ROM, DVD or portable hard drive	24 months after the day that the acquisition of the data is completed	Aeromagnetic processed data. Including pre and post microlevelling data. All coordinate data must also include clearly stated datum, spheroid and projection also clearly stated transformation parameters if not in same coordinate system as acquired in the field Gravity processed data. Data must include: descriptive headers, station, XY lat/long coordinates, meter reading, observed gravity value, elevation value calculation errors, final processed gravity value. All coordinate data must also include clearly stated datum, spheroid and projection, also clearly stated transformation parameters if not in same coordinate system as acquired in the field
Final processed images	PDF CD-ROM, DVD or portable hard drive	24 months after the day that the acquisition of the data is completed	

Table 18. Interpretative report and data for other surveys [r. 78]

Release of interpretative disclosable information [r. 92(4)]

- Data is released after **5 years** from the acquisition.

Report/Data	Format/Media	Submission Date	Remarks
Survey Interpretation Report and Data	PDF CD-ROM, DVD or portable hard drive	30 months after the day that the acquisition of the data is completed	Refer to **Schedule 16** for information required in this report
Digital images of interpretation maps	Geo-referenced TIFF or PDF CD-ROM, DVD or portable hard drive	30 months after the day that the acquisition of the data is completed	These include any maps included in the Interpretation report as separate geo-referenced TIFF or PDF images

Table 19. Monthly production reports [r. 79]

Release of basic disclosable information [r. 91(5)]

- The instrument is still in force: **2 years** after the activity was substantially completed.
- The instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.

Report/Data	Format/Media	Submission Date	Remarks
Monthly production report [r. 79]	Excel template Email	15 days after the day of production starting on the last day of the month to which the report relates	Refer to **Schedule 17** for information required in this report

Table 20. Petroleum mining samples [r. 80]

Release of mining samples after relevant day [r. 96]

- A sample collected and the instrument is still in force: **2 years** after the operation was substantially completed (i.e. rig release).
- A sample collected and the instrument has expired, or been surrendered, cancelled, revoked or terminated before the expiry date of the instrument: the day of the expiry, surrender, cancellation revocation or termination.

Samples	Quantity	Submission Date	Remarks
Ditch cuttings	1 set of 200 grams dry weight per sample interval	6 months after the rig release date	A minimum of 200g dry weight per sample interval set and thoroughly cleaned, dried and suitably packaged with indelible printing of well name, depth ranges
Full hole conventional cores	1/3 of the core	6 months after the rig release date	If cut – fresh core slabbed vertically Submission of raw imagery with core submission where possible
Full hole conventional cores	2/3 of the core	As soon as practicable after the titleholder completes tests on the core	If cut – fresh core slabbed vertically Submission of raw imagery with core submission where possible
Side wall core material	All material collected	18 months after the rig release date	
Liquid hydrocarbon samples	1 litre if available	If the sample is collected during the drilling of a well—6 months after the rig release date; or if the sample is collected during a test on a completed well—as soon as practicable after collection of the sample	If collected from wireline, drill stem or production tests: consultation with GA recommended Submit in an API approved safety container
Gaseous hydrocarbon samples	300 cm^3	As soon as practicable after completion of the test during which the sample is collected	If collected from wireline, drill stem or production tests: contact GA prior to submission Submit in an API approved safety container
Palynological slides and residues, paleontological material and petrological slides	All material collected	The day 18 months after the rig release date	If prepared

4.9 RMAR Part 9 – Release of technical information about petroleum and geothermal energy resources [r. 81 – r. 97 in the PSL RMAR 2015 and r. 82 – r. 98 in the PGER RMAR 2015]

Please note: Regulation numbers differ by one between the PSL and PGER RMAR 2015 from Part 8 onwards, following the inclusion of geothermal in r. 63 in the PGER regulations only.

All information and data submitted to DMIRS in accordance with the petroleum Acts shall remain confidential until the information is eligible for public release as prescribed in section 112 of the PGERA67 and section 118 of the PSLA82.

4.9.1 Data release administration – the 4 Divisions of Part 9

Part 9 has four Divisions:

Division 1 – Preliminary [r. 81 – r. 82]
Division 2 – Classification of documentary information [r. 83 – r. 88]
Division 3 – Release of documentary information [r. 89 – r. 94]
Division 4 – Release of mining samples [r. 95 – r. 98]

4.9.2 Division 1 – Preliminary [r. 81 – r. 82]

Division 1 defines terms used in this preliminary section. Terms defined include: basic information, disclosable information, documentary information, excluded information, exclusive data, interpretative information, mining sample, non-exclusive data, open information, operation, permanently confidential information, and seismic extracted data grid.

To assist in the management of metadata for wells and surveys, Division 1 outlines the definitions for always-open information.

Open information about a survey means any of the following information:

(a) the name of the survey
(b) the instrument under which the survey is being conducted
(c) the name of the instrument holder
(d) the basin and sub-basin (if applicable) in which the survey is being conducted
(e) the type of survey
(f) the size of the survey in:
    (i) for a 2-dimensional survey – kilometres; or
    (ii) for a 3-dimensional survey – square kilometres;
(g) the name of the vessel or aircraft conducting the survey
(h) the name of the contractor conducting the survey
(i) the dates on which the survey starts and ends or is proposed to start and end
(j) whether the survey is exclusive or non-exclusive
(k) navigation data for the survey, in the form of:
    (i) for a 2 dimensional survey – line ends and bends; or
    (ii) for a 3 dimensional seismic survey – a full fold polygon outline; or
    (iii) for other 3 dimensional surveys – a polygon outline.

Open information about a well means any of the following information:

(a) the name of the well
(b) the basin and sub-basin (if applicable) in which the well is located
(c) the well's latitude and longitude
(d) the name of the instrument area in which the well is located
(e) the name of the instrument holder
(f) the purpose of the well (for example development, appraisal, exploration or stratigraphy)
(g) if the well is a sidetrack – the name of the parent well
(h) the well's spud date
(i) the water depth at the well
(j) what is being used as the depth reference for the well (for example the Kelly Bushing or the rig floor)
(k) the height of the depth reference above sea level
(l) the name of the rig drilling the well
(m) the rig's make and model
(n) the name of the rig contractor
(o) the rig release date
(p) the status of the well (for example producing, suspended or decommissioned (i.e. abandoned)).

Excluded information is defined in r. 82 and is considered to be permanently confidential. Excluded information includes information about the list of items found in r. 82(2) or information contained in documents listed in r. 82(3). Note that if information contained in one of these documents is found in another document submitted to the Minister that is not in the list, then it is not considered to be excluded.

4.9.3 Division 2 – Classification of documentary information [r. 83 – r. 88]

Division 2 defines the meanings of permanently confidential information and interpretive information. Permanently confidential information is information that cannot ever be released publicly.

There are four circumstances where information is considered to be permanently confidential [r. 83]. These are:

- Information that is excluded.
- Information that is considered by the Minister to be a trade secret or if disclosed, would or could adversely affect the business, commercial or financial affairs of a person.
- When the Minister is told by someone in writing, that the information is a trade secret, or the disclosure of information would or could adversely affect the person's business, commercial or financial affairs and the Minister does not dispute it.
- When the Minister disputes that information given to him is confidential, but the time for making an objection to the notice of dispute has not elapsed or an objection to the notice of dispute remains in force.

Documentary information (i.e. reports and data) is interpretative information if the information is a conclusion drawn from, or an opinion based on, other documentary information [r. 84]. There are three situations in which documentary information is considered to be interpretative information. These are:

- When it is considered by the Minister to be a conclusion drawn or an opinion based wholly or partly on other documentary information.
- If the person supplying it to the Minister classified it as a conclusion drawn, or an opinion based wholly or partly from other documentary information and the Minister did not give a notice of dispute to the classification.
- When the person supplying it to the Minister classified it as a conclusion drawn, or an opinion based wholly or partly on other documentary information and the Minister did not accept the person's classification, and issued a notice disputing the classification under r. 84(3)(b), but the time for making an objection to the notice of dispute has not elapsed or an objection to the notice of dispute remains in force.

Table 21 lists what is considered to be interpretative data for surveys and wells.

Table 21. Interpretative information and data

Data Categories	Interpretative data
Gravity/magnetic surveys	Potential field qualitative and quantitative interpretation maps and reports
Seismic surveys	• Seismic picks, correlations and stratigraphic units on section • Time/depth contour maps • Interpretation reports
Lithological data	Core analysis studies carried out by oil company research units utilising proprietry techniques
Paleontological data	• Biostratigraphic zones • Conclusions drawn from the Species Lists and Range Charts
Source rock data	Conclusions in reports
Special core analyses	Relative permeability data, capillary pressure test data and water flood test results derived by petroleum company research units utilising propriety techniques. (All contractor derived data and results are defined as basic data.)
Regional geological data	• Regional basin-wide geological and paleoenvironmental maps • Regional formation structure and isopach maps
Reservoir engineering data	Results from test data such as formation permeability, kh and productivity index
Reservoir data	• Structure, isopach and other maps of reservoir units • Estimates of in-place and recoverable reserves • Reserve interpretation reports
Well drilling data	• Well interpretation on reports and maps • Biostratigraphic or lithostratigraphic zones • Composite well log which includes the above zones
Wireline and MWD log data	Petroleum company log interpretations
Fluid analyses	Conclusions drawn from such analyses
Formation tops	Formation tops (lithostratigraphic units) picked from electrical logs and other well data

Under r. 85, if the Minister does not consider that information should be classified as permanently confidential, as described in r. 83(5)(b) or r. 84(4)(b), then a dispute notice is issued by the Minister. In both instances, this must be given within 30 days after the Minister receives this documentary information. The regulation lists the information that must be contained in the notice given by the Minister, including the date by which an objection must be given, should the person object to the Minister's decision.

A person may object to the notice by a certain date given by the Minister in the notice, which must be at least 45 days after the date the notice was issued. A person who receives a notice under r. 85 is allowed to object to the classification of the information, either wholly or in part [r. 86]. The objection must be on the grounds that the information should be treated as permanently confidential or as interpretative information, or on both grounds. Any such objection must be made in writing to the Minister, on or before the date specified in the notice. If the Minister receives an objection from a person about the classification of information, the Minister must decide whether to allow or disallow the objection, either wholly or in part [r. 87]. The Minister may also allow the objection for a part and reject it for another part of the information. The Minister must advise the person in writing of the decision, within 45 days after receiving the objection. The circumstances under which an objection ceases to be in force are explained in r. 88. These circumstances are, the person withdraws the objection or the Minister disallows the objection.

4.9.4 Division 3 – Release of documentary information [r. 89 – r. 94]

Division 3 outlines the purpose and circumstances how the Minister can make documentary information publicly known or available to other persons [r. 89]. Under r. 90, the Minister may make open information about a well or survey publicly known at any time, despite any other requirements in this Division. Open information is information, about either a survey or a well, that is made publicly available at or before the commencement of the survey or of drilling. It serves to inform the other stakeholders including the public about the activities of the industry without releasing commercial or technical information.

Although the regulation allows that basic information to be released (i.e. it has become releasable) it does not mean that it will automatically be made publicly available or released by the Minister on that date.

Under r. 91, the Minister may make documentary information publicly known or available, if it is basic information and disclosable information and the relevant day for the information has passed. The regulation lists the relevant days for releasing the information in relation to:

(1) data collected through seismic surveys
(2) data from seismic surveys that has been reprocessed as a condition of the grant of an instrument
(3) for documentary information relating to other surveys
(4) other geological or geophysical surveys and other information relating to well operations.

Under r. 92, the Minister may make documentary information publicly known, if it is interpretative information and disclosable information, and relates to the subsoil or to petroleum or geothermal energy resources, and the relevant period for the information has passed (two years for well information and five years for other information).

Although the regulation allows that interpretative information to be released (i.e. it has become releasable) it does not mean that it will automatically be made publicly available or released by the Minister on that date.

In r. 93, the Minister may make documentary information publicly known prior to its relevant day, if it was already made public by the instrument holder who gave it to DMIRS. It can also be made publicly known if the instrument holder has consented in writing to it being made publicly known or available. However, if the information relates to a block under an SPA, an AA, or instrument of consent (i.e. a scientific investigation), the Minister may make documentary information publicly known if the information relates to a period when no permit, lease or licence was in force over the block.

The Minister may decide that fees are applicable when documentary information is made available to a person under r. 91 to r. 93 [r. 94].

4.9.5 Division 4 – Release of mining samples

Division 4 refers to the circumstance relating to the access, public and otherwise, to details of or inspection of petroleum mining samples. This includes ditch cuttings, conventional cores, sidewall core material, liquid and gaseous hydrocarbon samples, and palynological, paleontological and petrological slides and residues.

The Minister may make publically known any details of a sample or permit a person to inspect a sample [r. 95]. In general, samples are open-file two years after submission if the petroleum title is still live. If the permit has expired, been cancelled, revoked or terminated, the samples are immediately open-file. After that date, the public can request permission to view or sample the submitted petroleum samples [r. 96].

In r. 97, the Minister may disclose details of a sample, or permit a person to inspect a sample prior to the relevant day, if it was already made public by the instrument holder who gave it to DMIRS. It can also be made publicly known if the instrument holder has consented in writing to it being made publicly known or available. However, if a mining sample was obtained from a block under an SPA, an AA, or instrument of consent (i.e. a scientific investigation), the Minister may make details of a mining sample publicly known if the sample was obtained during a period when no permit, lease or licence was in force over the block.

The Minister may decide that fees are applicable when a mining sample is made available to a person under r. 96 to r. 97 [r. 98].

Some reference has been made in Tables 6 – 20 in Part 8 to release provisions covered under Part 9.

4.9.6 Viewing, borrowing and sampling of petroleum mining samples

Viewing, borrowing or sampling of confidential petroleum mining samples is restricted to the title holder(s) who obtained the samples or other persons nominated by them.

Requests for approval to view, borrow or sample petroleum mining samples should be directed to: **petdata@dmirs.wa.gov.au**

The following information should be provided with the request:

- name, address and country of the company or person seeking access
- title number
- well name(s)
- description and details of the samples (including depths where appropriate)
- details of level of access required (i.e. viewing, borrowing or sampling)
- confirmation that the title holder, requesting or approving access approval, was responsible for the drilling of the well
- evidence, in the form of a letter from the instrument holder, that access is approved by them (if the mining sample is confidential).

For viewing, borrowing or sampling of publicly released petroleum mining samples the contacts are (dependent on the type of the nominated samples): **petdata@dmirs.wa.gov.au** or **corelibrary.requests@dmirs.wa.gov.au**

4.10 RMAR Part 10 – Transition provisions [r. 99 – r. 102]

Part 10 of the RMAR 2015 came into effect on 1 July 2015. Terms defined in this Part [r. 99] have to do with identifying existing recovery operations or well activities that were undertaken prior to the commencement day, which is the day this Part came into operation, and continued on or after that day. The transition period is then 12 months beginning on the commencement day. The transition period ended on 1 July 2016.

Existing surveys [r. 100] do not require approval of the survey (as required under r. 5).

For a well existing prior to the commencement date, it is a requirement that any new, significant activity program applied for after the commencement of the RMAR 2015 will require the activity program to be in the form of a WMP [r. 101]. In any case, if there is no new activity on an existing well, it is a requirement that a WMP application for the current activity is submitted by 1 July 2016. This might just be a care and maintenance WMP if that is all that is happening on the well. If an existing well does not have an application submitted by 1 July 2016 for the approval of a WMP, then the title holder is in breach of the regulations.

In relation to existing recovery operations, it is a requirement that the licensee makes an application for the approval of an FMP, to be submitted before 1 July 2016 [r. 102]. Where an application under r. 58 is made for recovery of petroleum without an FMP in place, it is a requirement for the application to be made before 1 July 2016. A licensee will be in breach of the regulations if no such application is made by this date.

Appendix 1: Example of P1/90 field navigation data for 2D seismic surveys

```
H0100SURVEY AREA                       2D MSS, AC/P30, BROWSE BASIN, NW SHELF
H0102VESSEL DETAILS                    ACADIAN SEARCHER            1
H0103SOURCE DETAILS                    BOLT 3200 CU IN ARRAY       1    1
H0104STREAMER DETAILS                  SYNTRAK 480-24 RDA          1          1
H0200DATE OF SURVEY                    19990119-19990227
H0201DATE OF ISSUE OF TAPE             31-Mar-1999
H0202TAPE VERSION IDENTIFIER           UKOOA P1/90
H0300CLIENT                            BHP PETROLEUM (AUSTRALIA) PTY LTD
H0400GEOPHYSICAL CONTRACTOR            VERITAS DGC AUSTRALIA PTY. LTD
H0500POSITIONING CONTRACTOR            FUGRO SURVEY PTY LTD
H0600POSITIONING PROCESSING            SPRINT
H0700POSITIONING SYSTEM                VESSEL_1 SPECTRA MRDGPS DGPS
H0800COORDINATE SYSTEM                 CMP AT SHOTPOINT
H0900OFFSET SYSTEM TO CMP              1    2      0.00    -147.13
H0901OFFSET SYSTEM TO GPS SECOND       1    2     -0.20      -0.20
H0902OFFSET SYSTEM TO GPS PRIME        1    2     -0.70       0.40
H0903OFFSET SYSTEM TO STERN            1    2      0.00     -45.50
H0904OFFSET SYSTEM TO SOURCE           1    2      0.00     -87.46
H0905OFFSET SYSTEM TO CNG              1    2      0.00    -206.80
H1000CLOCK TIME                        GMT 0.000
H1100RECEIVER GROUPS PER SHOT          480
H1400GEODETIC DATUM AS SURVEY          AGD 84       Australian N 6378160.000 298.2500000
H1500GEODETIC DATUM FOR POST.          AGD 84       Australian N 6378160.000 298.2500000
H1700VERTICAL DATUM                    MSL                       : ECHOSOUNDER
H1800PROJECTION                        2UNIVERSAL TRANSVERSE MERCATOR
H1900ZONE                              51  SOUTHERN ORIENTATED
H2000GRID UNITS                        1INTERNATIONAL METERS      1.000000000000
H2001HEIGHT UNITS                      1INTERNATIONAL METER       1.000000000000
H2301GRID ORIGIN                       0 0 0.000N123 0 0.000E
H2302GRID COORDINATES                  500000.00E10000000.00N
H2401SCALE FACTOR                      0.9996000000
H2600  IN THE SEG-D HEADERS AND ON AUTOMATIC TAPE LABELLING THE SURVEY NAME WAS
H2600  TRUNCATED TO 4 CHARACTERS, I.E. FROM HBR1998B- TO HBRB- TO FIT INTO
H2600  8 CHARACTERS
H2600DEPTH DATA REDUCTION              CORRECTED FOR TRANSDUCER DEPTH
H2600DEPTH DATA REDUCTION              TIDAL CORRECTIONS APPLIED USING BHP PROVIDED
H2600DEPTH DATA REDUCTION              TIDE-TABLE FOR AC/P30
H2600DEPTH DATA REDUCTION              ECHOSOUNDER VEL/P AT 1509 M/S
H2600COMPASSES                         EXTERNAL, SELF BIASING, DIGICOURSE 318/321 IN 5011 BIRDS
H2600TAILBUOY                          NON ACTIVE
H2600SHOT RECORD DESCRIPTION           V=VESSEL REF POINT
H2600SHOT RECORD DESCRIPTION           E=ECHOSOUNDER POSITION
H2600SHOT RECORD DESCRIPTION           S=CENTRE OF SOURCE
H2600SHOT RECORD DESCRIPTION           C=NEAR CMP
H2600 Line HBR1998B-02                 From Shot 3437 To Shot 881
VHBR1998B-02      1        3437131957.15SCHEDULE 1224314.13E 469741.38526067.1 453.9 56 95128
EHBR1998B-02      1        3437131957.29SCHEDULE 1224314.53E 469753.18526063.0 453.9 56 95128
SHBR1998B-02      11       3437131958.44SCHEDULE 1224316.72E 469819.38526027.6 453.9 56 95128
CHBR1998B-02      111      3437131959.39SCHEDULE 1224318.45E 469871.48525998.6 453.9 56 95128
VHBR1998B-02      1        3436131956.66SCHEDULE 1224313.46E 469721.08526082.3 453.7 56 95138
EHBR1998B-02      1        3436131956.79SCHEDULE 1224313.85E 469732.98526078.4 453.7 56 95138
SHBR1998B-02      11       3436131957.92SCHEDULE 1224316.06E 469799.38526043.5 453.7 56 95138
CHBR1998B-02      111      3436131958.87SCHEDULE 1224317.79E 469851.58526014.5 453.7 56 95138
VHBR1998B-02      1        3435131956.23SCHEDULE 1224312.79E 469700.98526095.5 454.0 56 95148
```

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https://www.iogp.org

Appendix 2: Example of field navigation data for 3D seismic surveys

```
H01 SURVEY AREA                         HV11 TIMOR SEA AUSTRALIA
H02 SURVEY YEAR                         1990
H021 DATE OF TAPE                       08/31/90
H022 TAPE DENSITY                       6250
H03 CLIENT                              BHP AUSTRALIA
H04 GEOPHYSICAL CONTRACTOR              GECO GEOPHYSICAL CO. SFE
H05 POSITIONING CONTRACTOR              ONI
H06 NAV. PROCESSING CONTR.              GECO GEOPHYSICAL CO. NSA
H07 NAVIGATION SYSTEM                   SPOT
H08 COORDINATE LOCATION                 SOURCE AND RECEIVER POSITIONS
H090 OFFSET-SYSTEM TO COORDS            ANTENNA TO 1ST GRP = 229.0 METERS
H091 OFFSET-SYSTEM TO COORDS            SOURCE TO 1ST GRP = 133.0 M.
H10 CLOCK TIME                          G.M.T.
H11 NR. OF RECEIVERS                    480
H11 NR. OF STREAMERS                    TWO
H111 NUMBERING OF RECEIVERS             CABLE 1    REC#      1-240      STARBOARD
H111 NUMBERING OF RECEIVERS             CABLE 2    REC#      241-480    PORT
H12 SURVEY SPHEROID                     AUSTRALIAN NATIONAL              6378160.000 298.2500000
H13 POST PLOT SPHEROID                  AUSTRALIAN NATIONAL              6378160.000 298.2500000
H14 SURVEY DATUM                        AGD 66
H15 POST PLOT DATUM                     AGD 66
H160 DATUM SHIFT:                       PARAMETER FROM SURVEY TO POSTPLOT DATUM
H161 SHIFT CONSTANTS:(METERS)           DX=     00.00  DY=    00.00   DZ=    00.00
H161                                    XROT=    0.00  YROT=   0.00   ZROT=   0.00
H161                                    DIMENSIONLESS SCALE FACTOR = 0.000 PPM
H17 VERTICAL:                           SEA LEVEL
H18 PROJECTION:                         TRANSVERSE MERCATOR
H19 PROJECTION ZONE:                    UTM ZONE NO.51  SOUTHERN HEMISPHERE
H20 GRID UNIT:                          METER
H220 CENTRAL MERIDIAN:                  1230000.000E
H231 ORIGIN:                            0000000.000 1230000.000E
H232 FALSE EASTING, NORTHING            10000000.00N  500000.00E
H241 SCALE FACTOR:                      0.9996
H242 LONG. AT SCALE FACTOR:             1230000.000E
H26 COMMENTS: FINAL NAV OUTPUT WITH ONE SOURCE POSITION FOLLOWED BY 240
H26 COMMENTS: STARBOARD AND 240 PORT RECEIVER POSITIONS
SHV11-121      689123231.80SCHEDULE 1242745.77E 6589207 86130480 89.4194232733
R    1   6590463 86129820     2    6590546 86129730     3   6590629 86129630
R    4   6590712 86129540     5    6590795 86129450     6   6590878 86129350
R    7   6590961 86129260     8    6591044 86129170     9   6591128 86129070
R   10   6591211 86128980    11    6591294 86128890    12   6591377 86128790
R   13   6591460 86128700    14    6591543 86128610    15   6591627 86128510
R   16   6591710 86128420    17    6591793 86128330    18   6591876 86128230
R   19   6591959 86128140    20    6592043 86128050    21   6592126 86127950
R   22   6592209 86127860    23    6592293 86127770    24   6592376 86127670
R   25   6592459 86127580    26    6592543 86127490    27   6592626 86127390
```

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Appendix 3: Example of P1/90 post-binning navigation data for 3D seismic surveys

```
H0100 SURVEY & AREA NAME                HB96B, BUFFALO                  130396
H0101 GENERAL SURVEY DETAILS            DUAL CABLE, DUAL SOURCE 3D SURVEY
H0102 VESSEL DETAILS                    WESTERN HORIZON P131       1
H0103 SOURCE DETAILS                    N/A
H0104 STREAMER DETAILS                  N/A
H0200 DATE OF SURVEY                    MARCH TO MAY 1996
H0201 POSTPLOT DATE                     23 DECEMBER 1996
H0202 TAPE VERSION                      UKOOA-P1/1990 (WESTERN VERSION 01.01)
H0300 CLIENT NAME                       B.H.P.
H0400 GEOPHYSICAL CONTRACTOR            Western Geophysical
H0500 POSITIONING CONTRACTOR            Western Geophysical
H0600 PROCESSING CONTRACTOR             WESTERN ATLAS INTERNATIONAL
H0700 POSITIONING SYSTEM                WISDOM (TM) INTEGRATED NAV SYSTEM
H0800 COORDINATE LOCATION               STACK TRACE CENTRE OF BIN
H0900 POSITION OFFSETS                  N/A
H1000 CLOCK TIME                        GMT + 0 HOURS
H1100 RECEIVER GROUPS PER SHOT          480
H1400 GEODETIC DATUM AS SURVEYEDAGD-84 AUSTRALIAN N    6378160.000                    298.2500000
H1401 TRANSFORMATION PARAMETERS          -116.0   -50.5   141.7   -.230   -.390   -.344    .0983000
H1500 GEODETIC DATUM AS PLOTTED AGD-84 AUSTRALIAN N 6378160.000                       298.2500000
H1501 TRANSFORMATION PARAMETERS          -116.0   -50.5   141.7   -.230   -.390   -.344    .0983000
H1600 DATUM SHIFTS                           .0       .0      .0    .000    .000    .000    .0000000
H1700 VERTICAL DATUM                    MEAN SEA LEVEL            ECHO SOUNDER
H1800 PROJECTION TYPE                   002UNIVERSAL TRANSVERSE MERCATOR
H1900 UTM ZONE                          52S
H2000 GRID UNITS                        1METERS                   1.000000000000
H2001 HEIGHT UNITS                      1METRES                   1.000000000000
H2002 ANGULAR UNITS                     1DEGREES
H2200 CENTRAL MERIDIAN                  129 0  .000E
H2301 GRID ORIGIN                       0 0 .000N129 0 .000E
H2302 GRID COORDINATES AT ORIGIN 500000.00E10000000.00N
H2401 SCALE FACTOR                      .9996000000
H2402 SCALE FACTOR DEFINED AT           0 0 .000N129 0 .000E
H2600
H2600 DATUM ROTATION PARAMETERS ARE EXPRESSED IN COORDINATE FRAME SENSE
H2600
QHB96-10000                             1900104642.22SCHEDULE 1255821.88E 168901.08806882.5 528.2
QHB96-10000                             1901104641.89SCHEDULE 1255821.89E 168901.08806892.5 528.2
QHB96-10000                             1902104641.57SCHEDULE 1255821.89E 168901.08806902.5 529.8
QHB96-10000                             1903104641.24SCHEDULE 1255821.89E 168901.08806912.5 529.8
QHB96-10000                             1904104640.92SCHEDULE 1255821.89E 168901.08806922.5 529.8
QHB96-10000                             1905104640.59SCHEDULE 1255821.90E 168901.08806932.5 529.8
QHB96-10000                             1906104640.27SCHEDULE 1255821.90E 168901.08806942.5 529.8
QHB96-10000                             1907104639.94SCHEDULE 1255821.90E 168901.08806952.5 529.8
QHB96-10000                             1908104639.62SCHEDULE 1255821.91E 168901.08806962.5 529.8
QHB96-10000                             1909104639.29SCHEDULE 1255821.91E 168901.08806972.5 529.8
```

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Appendix 4: Example of polygon positioning data and processing report requirements for 3D seismic survey

Grid Definitions

Datum	AGD-84				
Spheroid	ANS	Semi-major axis	6378160.000		
		Semi-minor axis	6356774.719		
		Inverse flattening	298.25000		
		Eccentricity		0.006694	
Projection	UTM	Central meridian	120.00		
		Scale factor		0.99600	
		False Easting		50000.00	
		False Northing		10000000.00	
Datum shift from WGS-84 to LOCAL					
		dX	+116.0000	rX	-0.230000
		dY	+050.4700	rY	-0.390000
		dZ	500000.00	rZ	-0.344000
		Scale	-0098300000		
Navigation origin		Easting	636744.95		
(in-line 1001 crossline 1001)		Northing	8473164.88		
		Latitude	13 48 28.060 S		
		Longitude	124 15 540447 E		
Processing grid					
		CDP spacing	12.5m		
		CDP increment	1.0		
		Line spacing	12.5m		
		Line increment	1.0		
		Prospect angle	40.005000 degrees		
		Corner points of the grid			
		X-coords	**Y-coords**	**In-line**	**Crossline**
		635870.41	8472619.28	981	921
		686385.321	8524919.867	981	6738
		663634.5862	8445803.044	4069	921
		714149.4973	8498103.631	4069	6738
		Total number of cells	17971802		

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Appendix 5: Glossary of selected terms

Term	Definition
Day	Refers to a calendar day
Discovery of petroleum or geothermal energy	Means the initial recovery of any naturally occurring petroleum or geothermal energy in a petroleum or geothermal title. Recovery implies thats resources or energy must be brought to the surface from a known depth and geologic formation, in sufficient quantities for laboratory analysis of the composition
Instrument holder	As defined in the RMAR 2015: means any of the following: a title holder; the registered holder of an SPA; the registered holder of an AA; the person specified in an instrument of consent under section 116 of PGERA67 or 123 of PSLA82
Lessee	The registered holder of a lease (PGERA67)
Licensee	The registered holder of a licence (PGERA67)
Non-exclusive data	Means data that is made available for commercial sale or licence
Permittee	The registered holder of a permit (PGERA67)
Petroleum mining sample	A core or cutting from, or a sample of, the seabed or subsoil; or a sample of petroleum recovered; or a sample of fluid recovered (other than fluid petroleum) that includes a portion of such a core, cutting or sample (from section 150A of PGERA67)
Petroleum pool	A naturally occurring discrete accumulation of petroleum (PGERA67)
Registered holder	In relation to a permit, drilling reservation, lease, licence, special prospecting authority or access authority – under the PGERA67 or PSLA82: means the person whose name is for the time being shown in the Register as being the holder of the permit, drilling reservation, lease, licence, special prospecting authority or access authority (PGERA67). Equivalent terms are lessee, licensee and permittee
Reservoir	A rock formation in the subsurface that accommodates an accumulation of hydrocarbons/water
Significant	Sufficiently great or important to be worthy of attention; noteworthy; of or relating to observations that are unlikely to occur by chance and that therefore indicate a systematic cause
Title holder	As defined in the RMAR 2015: means any of the following: a permittee; the registered holder of a drilling reservation; a lessee; a licensee. **Note – does not include the registered holder of a special prospecting authority or the person specified in an instrument of consent under either PGERA67 or PSLA82**

Appendix 6: Acronyms

AA	Access Authority
AGEA	Australian Geothermal Energy Association
AHD	Australian height datum
ALARP	As low as reasonably practicable
ASX	Australia Stock Exchange
DMIRS	Department of Mines, Industry Regulation and Safety
EP	Environment plan
EPT	Extended production test
FMP	Field management plan
GERDP	Geothermal energy resources development plan
HSE	Health, safety, environment
NAA	National Archives Australia
NORMs	Naturally occurring radioactive materials
PGERA67	*Petroleum and Geothermal Energy Resources Act 1967*
PGER RMAR 2015	Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015
PGR	Petroleum and Geothermal Register
PRMS	Petroleum Resources Management System
PSLA82	*Petroleum (Submerged Lands) Act 1982*
PSL RMAR 2015	Petroleum (Submerged Lands) (Resource Management and Administration) Regulations 2015
RoR	Rate of recovery
SEIG	Statutory Exploration and Information Group
SPA	Special Prospecting Authority
SPE	Society of Petroleum Engineers
WCR	Well completion report
WMP	Well management plan

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