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Northern Perth Basin subsurface resources interaction

Final report

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CSIRO Energy

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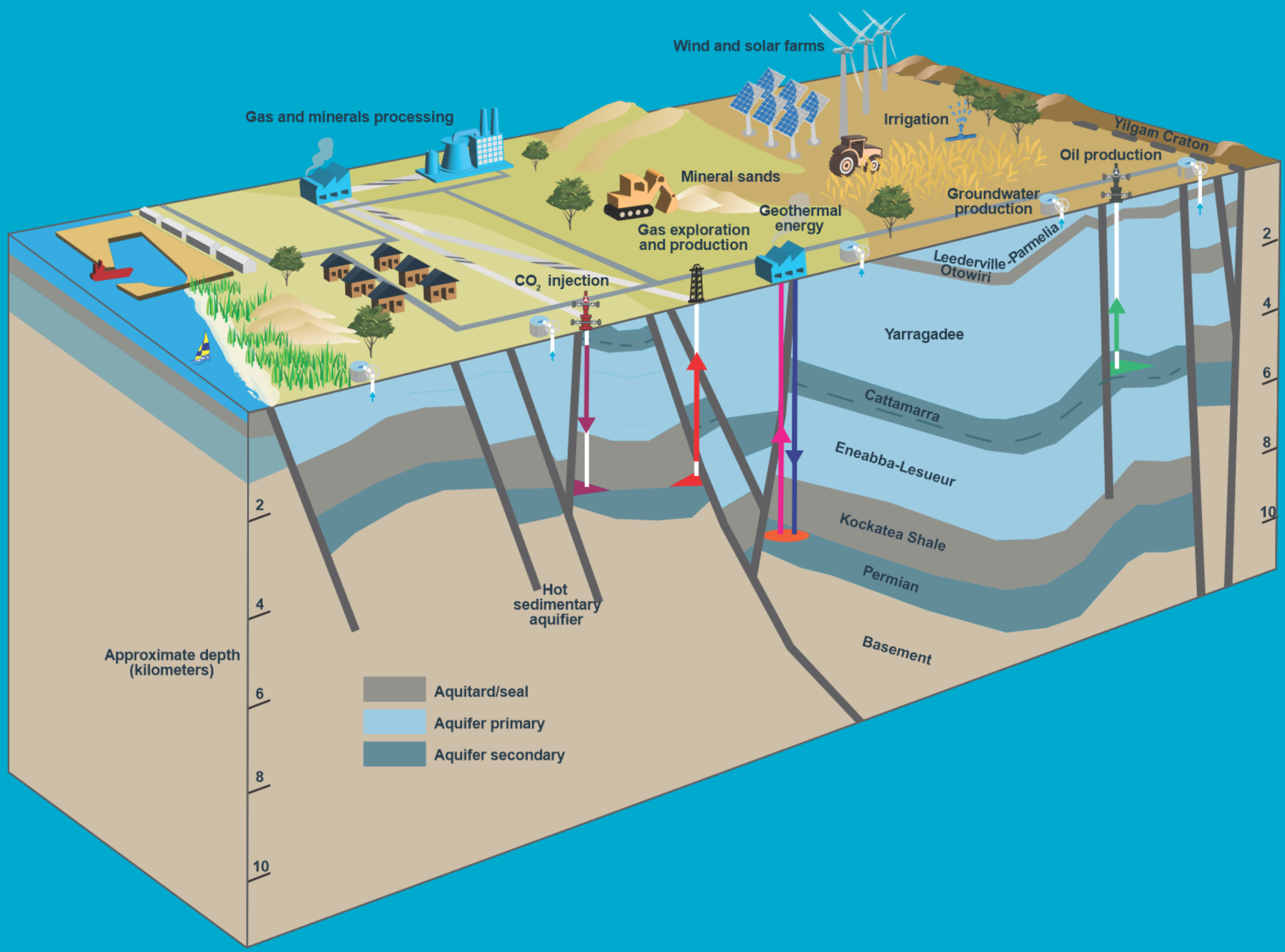

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Acknowledgement of Country

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Executive Summary

The northern Perth Basin is experiencing a rise in subsurface and above-ground resource development activities, including natural gas, geothermal energy, carbon geological storage (CGS), underground gas storage (UGS), and groundwater extraction. The expanding industrial footprint presents opportunities and challenges, with resource developments either complementing one another or creating potential conflicts due to competing land and subsurface use.

This study aims to provide a data-driven framework for evaluating subsurface resource interactions and identifying potential risks and opportunities for regulators, industries and communities. The project uses a Geographic Information System (GIS)-based multi-criteria and hierarchy evaluation process to assess the suitability of different resources and quantify their spatial interactions.

At a regional scale, subsurface resource interactions in the northern Perth Basin follow 3 primary stratigraphically controlled categories:

1. **Petroleum, CGS, UGS, and geothermal resources within the Permian intervals below the Kockatea Shale:** this interval has the highest potential for resource interaction, with prospective CGS and petroleum areas strongly overlapping due to their reliance on shared reservoirs and seals. While geothermal and UGS show potential, their viability remains uncertain due to a limited number of current geothermal and UGS projects.
2. **Groundwater, petroleum, and CGS within the Triassic-Lower Jurassic Cattamarra Coal Measures/Eneabba/Lesueur interval:** the potential for resource interaction in this interval is moderate to low. This is because the interval is poorly suited for CGS and petroleum as primary interacting resources. Usable groundwater is present, but it is located either in sub-crop areas along the coast, where no other resources are present, or at uneconomic depths. Also, groundwater remains stratigraphically isolated from deeper resources, minimising direct competition.
3. **Groundwater resources within the Upper Jurassic-Cenozoic interval:** these aquifers are the region's primary groundwater source, supporting municipal, agricultural, mining, and industrial uses. They are largely separated from deeper resource units, although localised migration pathways may exist and warrant further investigation.

The study found that direct interaction between deep subsurface resources and groundwater is limited, as thick regional seals typically prevent hydraulic connectivity. However, localised migration pathways could exist in areas of high fault displacement or legacy well networks, potentially allowing for fluid movement between deep and shallow subsurface systems.

Key findings and implications:

- **Resource competition and synergy:** zones with the highest resource interaction occur in a northern hotspot inland of Geraldton, particularly in the Beharra Springs, Dongara, and Donkey Creek terraces. This area requires integrated subsurface planning to balance petroleum extraction, carbon geological storage, and potential geothermal or gas storage projects.

- **Groundwater use considerations:** while direct conflicts between groundwater and deeper resources are minimal, industrial groundwater should be accounted for to ensure sustainable water allocation, particularly as new developments increase demand. Groundwater resources are particularly strained in the southern part of the study area, near Perth, where a seawater desalination plant is planned at Alkimos to accommodate increasing demand. Some excess resources remain in the Jurien and Arrowsmith management areas further north, where groundwater allocation plans are currently being updated.
- **Structural influence on interactions:** faults and legacy petroleum wells present potential fluid migration risks in some areas, emphasising the need for ongoing monitoring and risk assessments for resource extraction and groundwater protection.
- **Regulatory and planning needs:** future subsurface development strategies may require regulatory coordination and staged resource use, ensuring that industries can coexist while minimising environmental and water resource impacts.

This study provides foundations for future resource management decisions at the basin scale, offering a spatial framework for assessing subsurface resource interactions in the northern Perth Basin. Further technical assessments will be necessary at the local scale to refine long-term resource planning strategies, focusing on the role of faults in lateral and vertical hydraulic communication, groundwater allocations, demand for CGS and geothermal energy viability. Sustainable resource management that integrates economic, environmental and societal considerations will be essential in ensuring energy projects, groundwater use and industrial development in the region can co-exist. The government, in consultation with industry and community stakeholders, may need to prioritise resources and ensure that adequate compensation provisions are in place in case of potential detrimental impacts.

1. Introduction

The northern Perth Basin, located in Western Australia's Mid West region, is seeing a significant increase in energy-related industrial activities. This includes subsurface resource development (natural gas, geothermal energy, geological storage of carbon dioxide, natural hydrogen, underground hydrogen storage, sediment-hosted mineral deposits) and above-ground renewable energy developments (wind and solar farms) (Figure 1). Various land-use and subsurface demands are becoming increasingly challenging for regulators and residents in the community. Many potential industrial activities could complement one another (for example, the use of renewable energy to power transport of gas, mining and communities). However, other activities could conflict, such as the use of subsurface structures for storage of natural gas, hydrogen or carbon dioxide, or pressure effects beyond the storage complex. Industrial activities may also have varying surface footprints, energy needs and water use. This project aims to evaluate the activities and map out interdependencies and risks that could occur if they compete. Staging and timing of activities, sharing costs and identifying opportunities for improvement within the community (such as more renewable energy or cleaner water) may be beneficial. Conducting an evaluation of resource interactions in the region can help understand the challenges and risks mitigated, resulting in better outcomes for the resources industry and for people who live and work in the region.

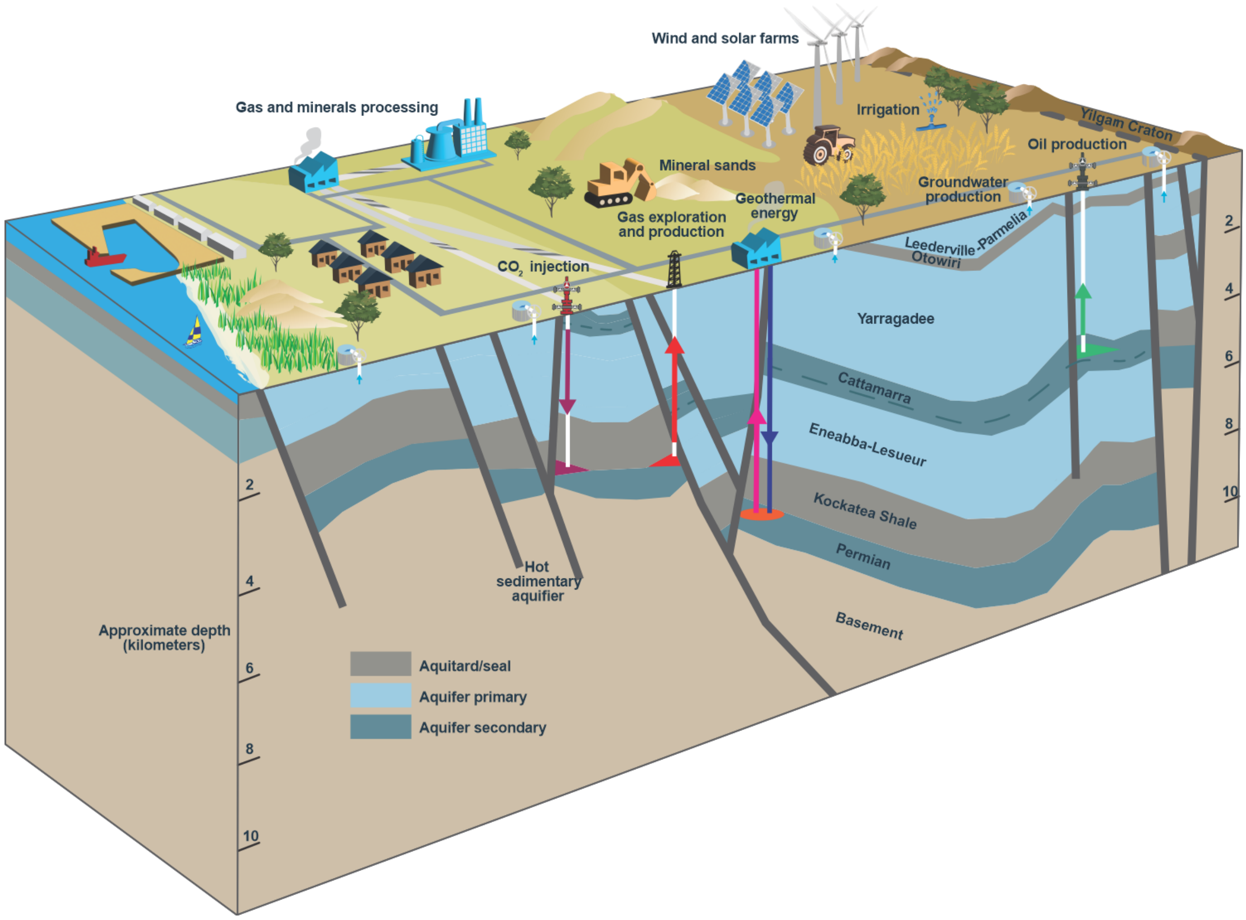

Figure 1. Diagrammatic representation of subsurface resources development in the northern Perth Basin.

1.1. Project description

The area of interest is the northern region of the Perth Basin, which hosts multiple subsurface resource developments (Figure 2). The study area stretches along the Western Australian coast from Gingin to Geraldton and is surrounded by the Darling Hills to the east. Major towns in the area include Dongara, Leeman, Eneabba and Cervantes. The primary objective of this project was to provide a framework for data-driven decision-making and for managing the economic, environmental and social aspects of developing subsurface resources in the northern Perth Basin.

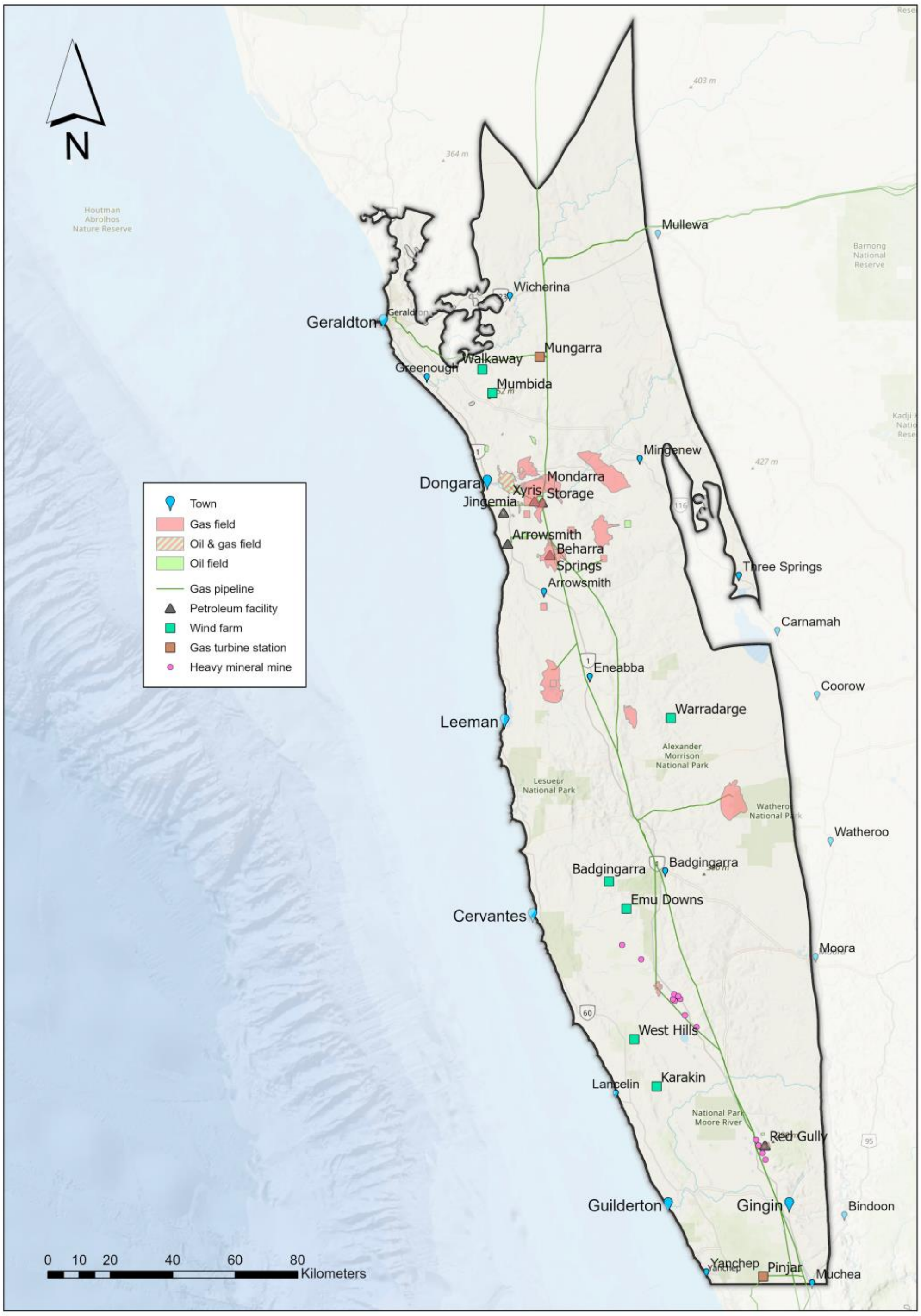

Figure 2. Map of the northern Perth Basin showing locations of petroleum fields and facilities, and electricity generation.

This project evaluated potential resource interactions at the basin scale by modelling the distribution of each subsurface resource, then identifying their overlap or interaction, either in specific geological intervals or cumulatively over the basin.

By identifying key natural resources, stakeholders, potential interactions and risks, this project aimed to:

- Assess the likelihood of different industry activities to coincide to understand possible interactions and mitigate basin resource conflicts.
- Equip community groups and regulators with the necessary tools and information to prioritise and stage future projects involving onshore gas and related activities, with a focus on the potential impacts on groundwater resources.
- Offer a systematic approach to assess and manage the risks associated with subsurface resource development, including potential contamination of groundwater resources.
- Provide an assessment to support the development of subsurface and above-ground resources in a mutually beneficial and sustainable way, emphasising the preservation of quality and availability of the region's groundwater resources.

The workflow for evaluating resource interactions in the northern Perth Basin builds on methodology developed by Michael *et al.* (2013) for basin resource management strategies associated with the development of large-scale carbon dioxide (CO_2) geological storage within pre-existing and future activities in a region.

Surface elements, including industrial facilities (Figure 2), aboriginal heritage sites, legislated lands, and agricultural areas (Figure 3), will likely influence the feasibility and planning of future subsurface resource developments in the northern Perth Basin. While these elements play a critical role in determining land access, regulatory constraints, and environmental considerations, the current study focuses solely on subsurface resource interactions. It does not incorporate surface land-use factors into the assessment. However, understanding the spatial distribution of these surface constraints is essential for future integrated resource management, helping to align economic development with cultural, environmental and land-use priorities.

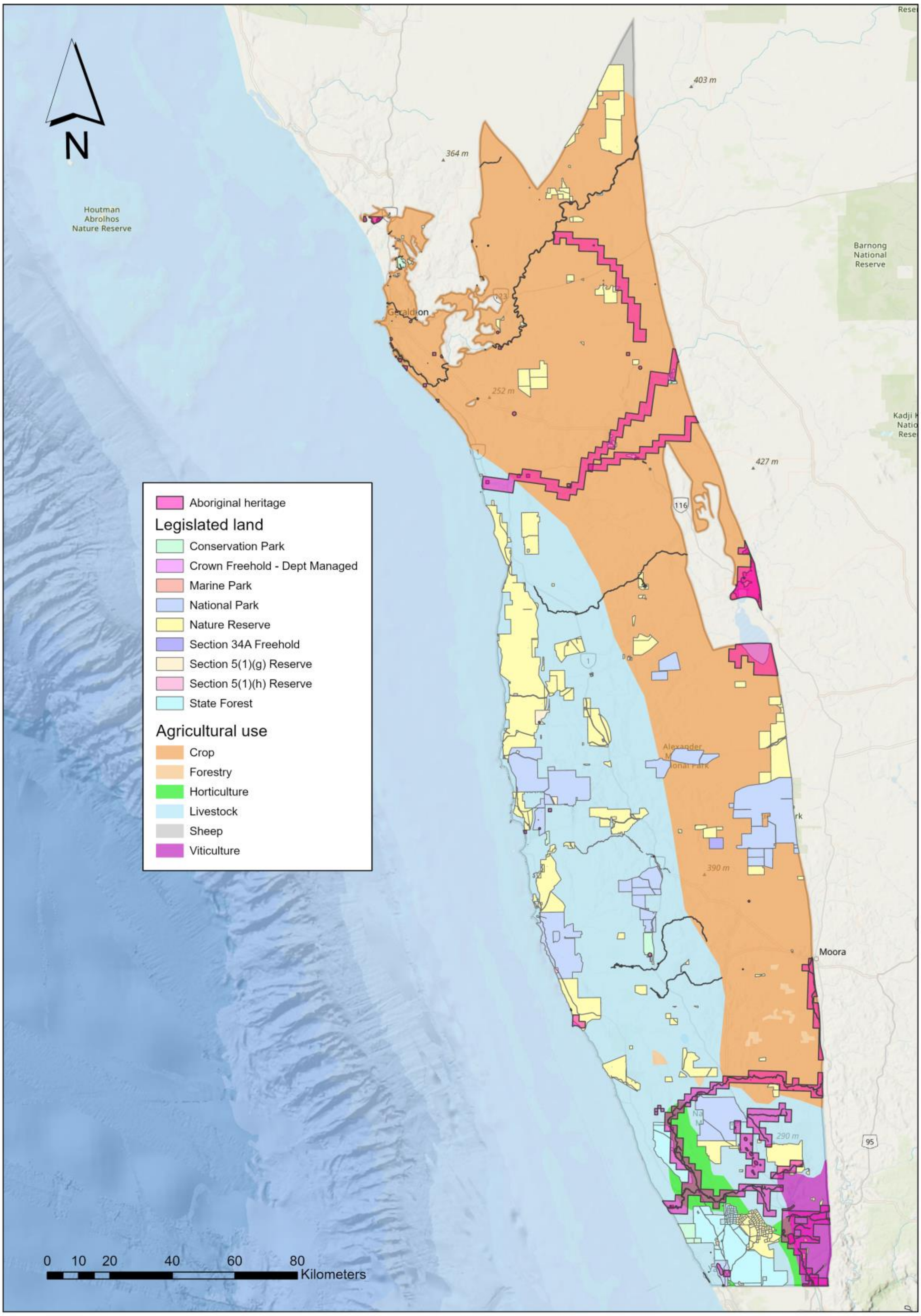

Figure 3. Distribution of Aboriginal heritage sites, legislated lands, and agricultural areas.

1.2. Northern Perth Basin framework

Geologically, the zone of interest for this resource interaction assessment encompasses the area from the Beermullah Trough in the south to the Irwin Terrace in the north (Figure 4). The Coolcalalaya Sub-basin is excluded from this assessment.

1.2.1. Geology

The northern part of the Perth Basin is characterised by an intracratonic rift basin that developed through multiple phases of rifting and sedimentation. The description below is based on work by Geoscience Australia (2020 and 2023), Thomas (2014), and Mory and Iasky (1996).

During the late Carboniferous to early Permian intervals (Figure 5), initial rifting led to the deposition of fluvial and glaciogenic sediments. Key formations deposited at this time include the Irwin River Coal Measures and the Carynginia Formation. These units reflect the interplay between glacial, fluvial, and deltaic processes in a cold-temperate climate setting. The end of early Permian rifting is marked by a regional uplift, followed by late Permian to Early Triassic early post-rift subsidence, and the deposition of alluvial fans, fan-deltas, deltaic and coastal sediments forming the Wagina and Dongara sandstones (Mory and Iasky, 1996).

During the Triassic interval (Figure 5), continued rifting and subsidence resulted in deposition of the Kockatea Shale and the Lesueur Sandstone. The Kockatea Shale is particularly significant as a major hydrocarbon source rock, while the Lesueur Sandstone serves as a regional aquifer without significant hydrocarbon accumulation. The depositional environment during this period varied from fluvial and deltaic to shallow marine settings, influenced by the region's tectonic evolution.

The Mesozoic era (Figure 5), particularly from the late Triassic to early Jurassic interval, was marked by rifting associated with the break-up of Gondwana. This tectonic activity led to the formation of major structural features and influenced the deposition of formations such as the Cattamarra Coal Measures and the Eneabba Formation. These formations represent a range of environments, from coal-forming swamps to shallow marine conditions. The final rifting phase in the onshore Perth Basin occurred in the Late Jurassic to Early Cretaceous interval, preceding continental break-up between Australia and Greater India (Norvick, 2004). It coincides with the deposition of the Yarragadee Formation and the onset of major extensional faulting.

The northern Perth Basin's structural framework (Figure 4 and Figure **6**) is defined by several prominent features, including the Dandaragan Trough, Beagle Ridge, and Eneabba Terrace. Major faults such as the Darling Fault and the Urella Fault have significantly influenced the Basin's development, creating accommodation space for sediment deposition and forming structural traps for hydrocarbons.

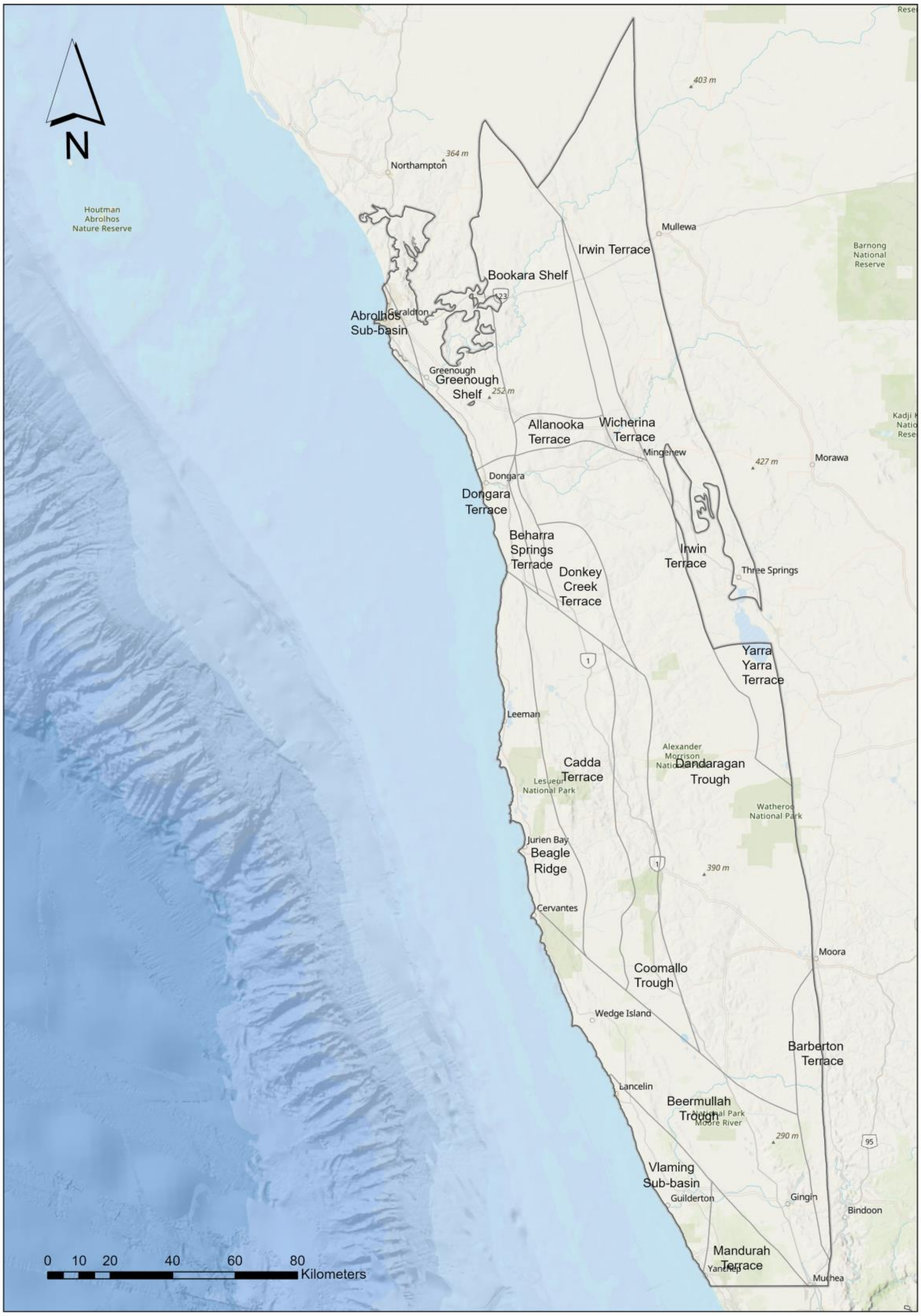

Figure 4. Project area of interest in the northern Perth Basin with tectonic units.

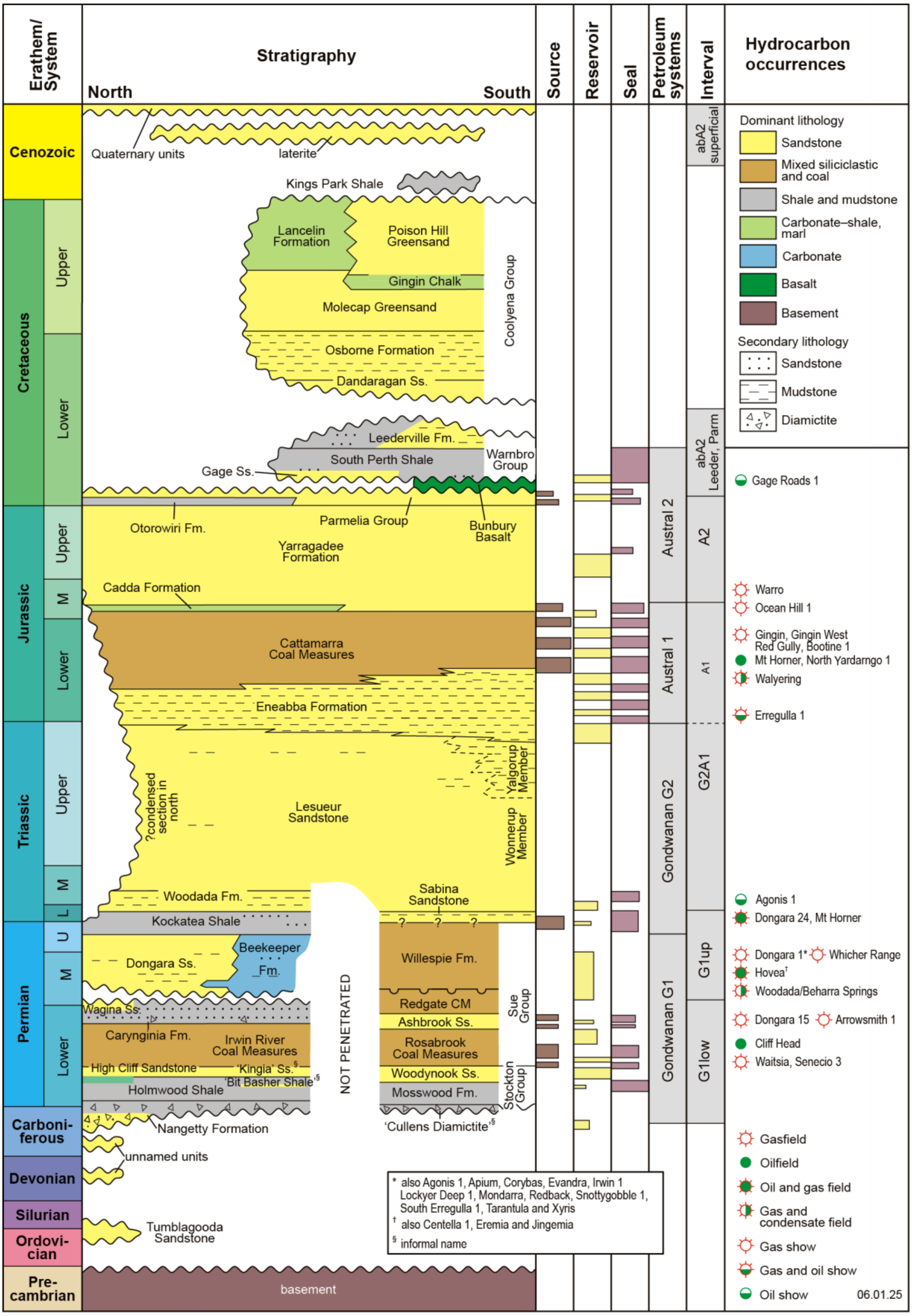

Figure 5. Stratigraphy and petroleum systems of the Perth Basin (modified from A. Mory personal communication, 2025). The interval column shows the main stratigraphic intervals used for the evaluation of resource interactions.

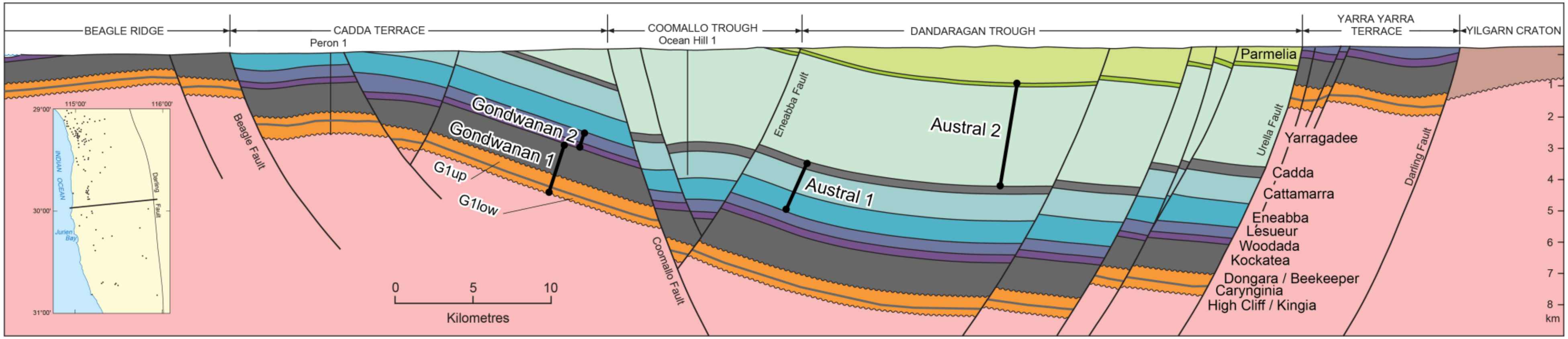

Figure 6. Cross-section of the northern Perth Basin showing the distribution of the sedimentary sequences above the Precambrian basement. The intervals used for the suitability and interaction maps are labelled. Modified from Mory and Iasky (1996).

Structural framework

The project area in the onshore northern Perth Basin is divided into 18 tectonic units (Figure 4). Table 1 present a short description of the main structural elements in the project area, from north to south. A full description can be found in Thomas (2014).

Table 1. Description of tectonic units.

Tectonic Unit	Structure	Main Fault Boundaries	Stratigraphy / Age
Abrolhos Sub-basin	Mostly offshore sub-basin	Poorly mapped onshore	Permian to younger
Greenough Shelf	Shallow basement shelf; progressive onlap northward	Allanooka Fault (S), Mountain Bridge Fault (E)	Permian to younger
Bookara Shelf	Structured shelf; bounded by E–W and NW-trending faults	Bookara Fault (S), Wicherina Fault (E), Mountain Bridge Fault (W)	Permian and possibly older
Irwin Terrace	Narrow, NNW half-graben	Urella Fault (W), Darling Fault (E)	Ordovician–Devonian to Middle Permian
Wicherina Terrace	Narrow half-graben bounded by westerly dipping faults	Wicherina Fault (W), Urella Fault (E), Allanooka Fault (S)	Permian and possibly older
Allanooka Terrace	Bounded block with eastward thickening Permian strata	Allanooka Fault (S), Bookara Fault (N), Wicherina Fault (E), Mountain Bridge Fault (W)	Permian
Dongara Terrace	Faulted block	Mountain Bridge Fault (E), Geraldton Fault (W)	Jurassic and older
Beharra Springs Terrace	Broad dome; 'intermediate' terrace	Between Dongara and Donkey Creek Terraces, Mountain Bridge Fault (E)	Permian
Donkey Creek Terrace	Asymmetric graben	Eneabba Fault (E & N), Abrolhos Transfer Fault (S)	Early Permian
Dandaragan Trough	Deepest onshore N–S trending half-graben	Urella Fault (E), Darling Fault (E), Muchea Fault (E), Eneabba Faults (W)	Permian to Cenozoic
Yarra Yarra Terrace	N-S trending half-graben	Urella Fault (W), Darling Fault (E)	Mesozoic
Beagle Ridge	NNW–SSE trending horst	Beagle Faults (E), Geraldton Fault (W), Abrolhos Transfer Fault (N), Cervantes Transfer Fault (S)	Likely Carboniferous–Permian
Cadda Terrace	Fault-bounded N-S terrace with uplift/erosion after Early Triassic	Beagle Faults (W), Eneabba Faults (E)	Triassic and older
Coomallo Trough	Fault bounded N-S Graben	Coomallo Fault (W), Eneabba Fault (E)	Likely Permian to Cenozoic
Barberton Terrace	Elongate N-S half-graben	Darling Fault (E), Muchea Fault (W)	Triassic -Jurassic
Beermullah Trough	Structurally low NW-trending depocentre	Darling Fault (E), Muchea Fault (E), Cervantes Transfer Fault (N), Turtle Dove Ridge (W)	Mesozoic (implied)
Vlaming Sub-basin	Mostly offshore sub-basin	Turtle Dove Ridge (E)	Likely Permian to Cenozoic
Mandurah Terrace	Structurally intermediate block	Darling Fault (E), Turtle Dove Ridge (E)	Likely Permian to Cenozoic

Potential leakage mechanisms and pathways

One major risk in the exploration of the offshore northern Perth Basin is the loss of petroleum accumulations due to trap breach over time. This is associated with the region's main Permian-

Triassic oil/gas play, where evidence of past leakage (such as palaeo-oil columns) has been identified (Nicholson *et al.,* 2012; Kempton *et al.,* 2011). These features indicate that some traps may have been breached in the past, leading to the dissipation of hydrocarbons long before present-day exploration. Importantly, this refers to ancient geological processes and does not imply an ongoing or current leakage risk.

Palaeo-oil columns were found in Permian reservoir sandstones below the Triassic Kockatea Shale regional seal in 14 of the 18 wells analysed from the Abrolhos Sub-basin. Further evidence from the Houtman Sub-basin, where a palaeo-oil column in Houtman-1 was discovered, indicates an effective oil-charge system in Jurassic strata. The breach of these palaeo-accumulations in the offshore northern Perth Basin is primarily attributed to fault reactivation and structuring associated with several geological events:

- **Jurassic-Early Cretaceous extension and continental breakup in the Valanginian**: Fault movements during this period caused significant structural reconfigurations, which could have compromised the integrity of petroleum traps.
- **Tilting and thermal subsidence of the margin post-breakup**: Following the Valanginian breakup, tilting of the margin may have further disrupted the traps, causing leakage.
- **Inversion of faults during the Miocene**: The collision of the Australian and Eurasian plates during the Miocene resulted in fault inversion, which could have breached existing traps, allowing hydrocarbons to escape.

While these examples are from offshore, the petroleum systems in the onshore northern Perth Basin share many similarities in stratigraphy, source and reservoir intervals. However, the degree and timing of fault reactivation and structural deformation are more site-specific and may vary between offshore and onshore settings.

It is important to understand the sealing behaviour of faults for the containment of stored gas in the northern Perth Basin, as it is controlled by the stress state on fault planes, which influences strain and reactivation under varying formation pressures. Additionally, the geological history of the fault (including burial and cementation processes), and the characteristics of the fault rock (created by deformation and incorporation of materials during displacement), fundamentally control cross-fault and upfault flow.

Faults can act as membrane seals by impeding cross-fault flow between juxtaposed permeable units due to the petrophysical properties of the fault rock. Conversely, they can also provide fault-parallel conduits for flow between vertically separate flow units (Manzocchi *et al.,* 2010). The type of fault-zone rock depends on the composition of the faulted sequence, the burial and temperature conditions during and after faulting (Yielding *et al.*, 2010).

These geological processes and fault characteristics significantly impact the preservation and containment of fluids in the subsurface, making fault sealing behaviour a critical factor in the exploration and development of resources in the northern Perth Basin.

1.2.2. Basin hydrogeology

Hydrogeology describes the origin, flow and quality of subsurface groundwater and how it interacts with the geological layers. In the northern Perth Basin, there are 3 major flow systems:

1. **Local flow systems** driven by meteoric (rainfall) recharge in areas of local topographic highs and discharge in smaller rivers and lakes. These are typically active at depths of < 200 m and involve fresh groundwater in the sub- or outcrop areas of Parmelia-Leederville, Yarragadee, and Eneabba-Lesueur aquifers (Figure 7). More details are provided in Section 3.5 Groundwater resources.
2. An **intermediate flow system** down to ~ 2000 m depth, with meteoric recharge in the eastward and westward regional flow of relatively fresh formation water towards the coast.
3. A **deep, stagnant to sluggish flow system** of > 2000 m depth, with slow westward flow of brackish to saline formation water.

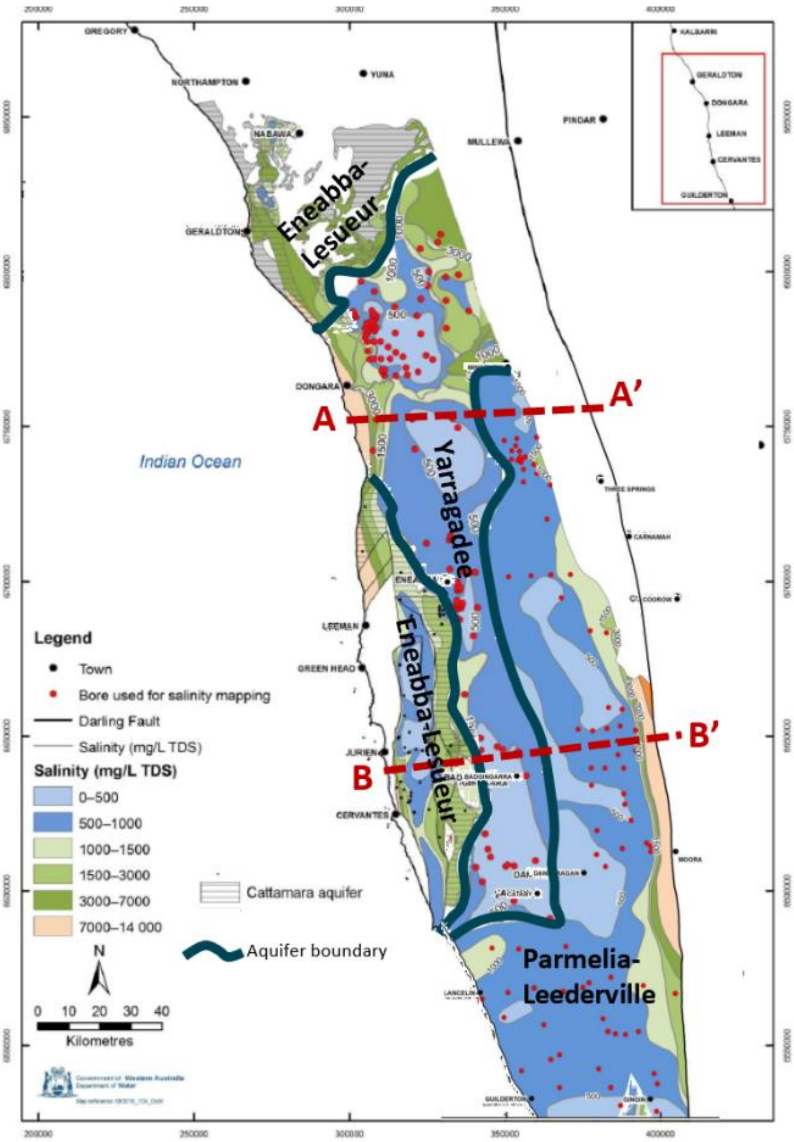

Figure 7. Salinity distribution in near-surface aquifers in the northern Perth Basin (modified from Department of Water, 2017). The red lines depict the approximate location of the cross-sections AA' and BB' shown in Figure 8 and Figure 9, respectively.

The geological structure and distribution of aquifers and aquitards in the northern Perth Basin lead to local differences in the shape and depth of the 3 flow systems as depicted in the cross-sections in Figure 8 and Figure 9. In the northern part of the study area, fresh, usable groundwater with salinity < 1000 mg/l is restricted to the upper 200 m in the Dandaragan Trough, and the intermediate flow system is largely active above the Cattamarra Coal Measures (Figure 8). In the area of the Northampton Uplift, higher salinities (> 7000 mg/l) are observed at shallow depths along the coast, likely due to incursion and mixing with seawater.

The highest salinities (> 30,000 mg/l) in the northern Perth Basin are observed offshore, in the coastal region directly affected by seawater (~35,000 mg/l), and in the deeper parts of the basin, largely in the Permian aquifers below the Kockatea Shale. In these deep parts of the basin, water that was trapped in the rocks during sedimentation, known as connate water, has not been significantly affected by mixing with fresh meteoric water. Maximum salinities measured in deep petroleum wells (> 2000 m depth) are in the order of 40,000 mg/l.

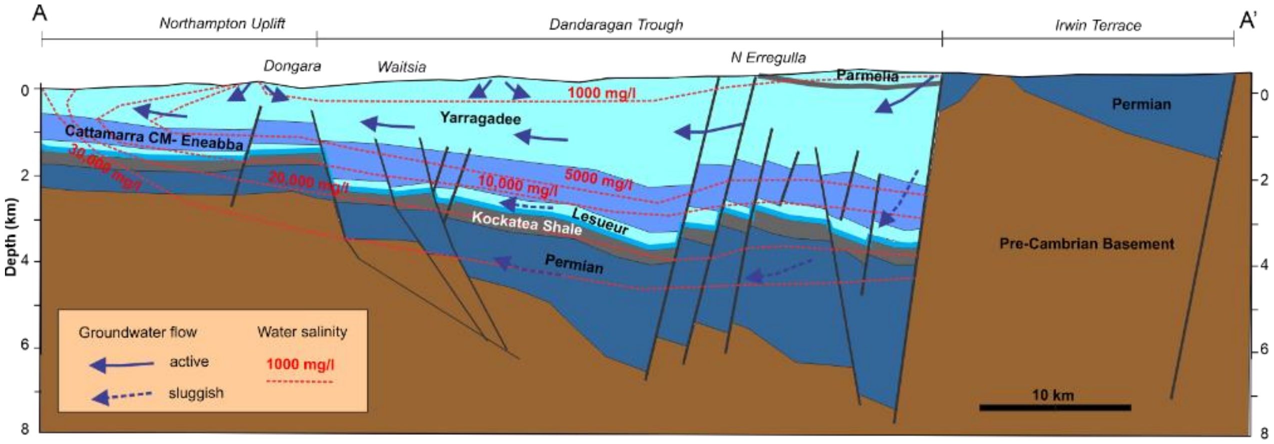

Figure 8. Conceptual hydrogeological W-E cross-section showing salinity distribution and flow directions of formation water in the northern part of the northern Perth Basin. The cross-section location is shown as line AA' in Figure 7. The salinity distribution and flow in the upper ~ 1000 m are based on maps and data from the Department of Water (2017). Deeper interpretations are highly uncertain and are based on less abundant pressure and salinity observations in petroleum wells.

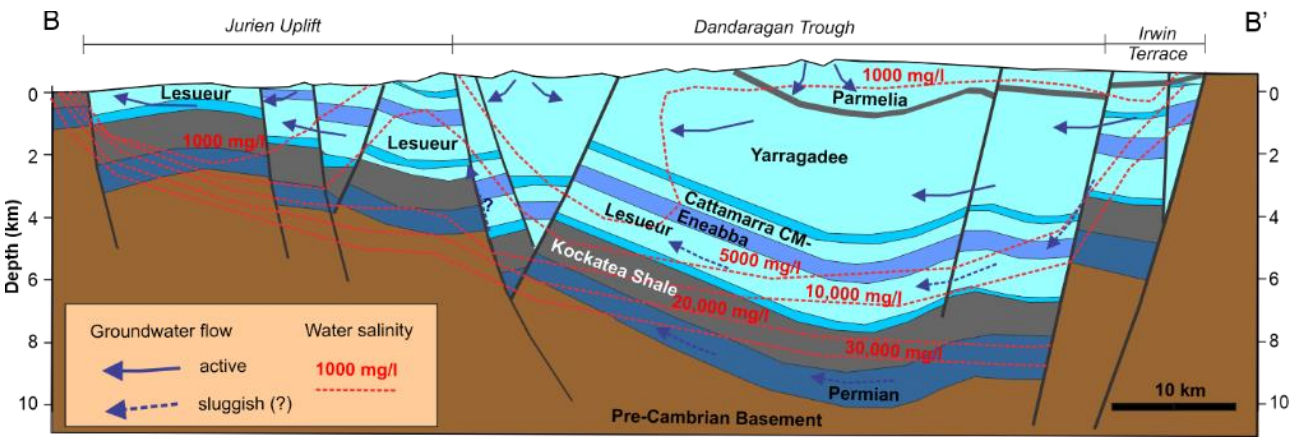

Figure 9. Conceptual hydrogeological W-E cross-section showing salinity distribution and flow directions of formation water in the central part of the northern Perth Basin. The cross-section location is shown as line BB' in Figure 7. The salinity distribution and flow in the upper ~ 1000 m are based on maps and data from the Department of Water (2017). Deeper interpretations are highly uncertain and are based on less abundant pressure and salinity observations in petroleum wells.

1.3. Interaction of subsurface resources development

The subsurface contains various resources valuable to our economy, in the form of mineral deposits or coal, or as fluids within the pore space (for example, groundwater, oil and gas). Energy can be produced in the form naturally heated groundwater water, and the pore space itself can be a commodity for natural gas, carbon dioxide or hydrogen storage. These resources are typically found at different depth ranges (Figure 10), however, they can overlap both geographically and vertically in the same geological formation in some instances.

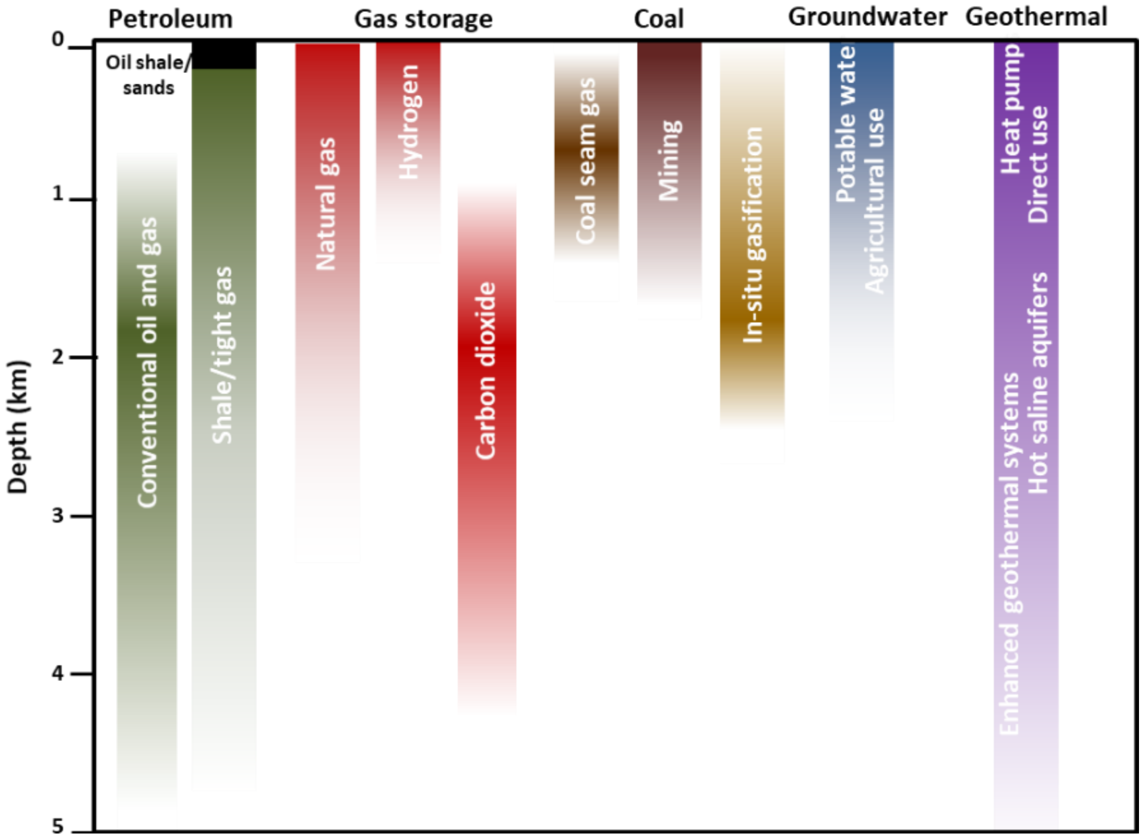

Figure 10. Typical depth ranges for various subsurface resource activities (modified from Michael *et al.,* 2016).

Interaction between subsurface resources can be in the form of (Michael *et al.*, 2016 and Field *et al.*, 2017):

1. **Direct contact, with:**
    a. Positive impacts
        i. CO_2 injection in oil or gas fields for enhanced recovery.
        ii. Storage of natural gas, hydrogen or CO_2 in depleted gas fields.
        iii. Geothermal use of co-produced water from hydrocarbon production.
    b. Negative impacts
        i. Contamination of oil or gas reservoirs.
        ii. Contamination or sterilisation of future resources.
        iii. Contamination of potable or usable groundwater.

2. **Pressure communication, with:**
    a. Positive impacts
        i. Fluid injection providing reservoir pressure support.
        ii. Fluid injection counteracting regional pressure decline or subsidence.
    b. Negative impacts
        i. Regional production-induced pressure drawdown, affecting production of neighbouring resources.
        ii. Displacement of brines into neighbouring reservoirs or into groundwater aquifers induced by fluid (i.e. CO_2) injection.
        iii. Reactivation of faults/induced seismicity.

The general potential for interaction between specific resources was investigated by Field *et al.* (2017) and is summarised in Figure 11.

In many instances, petroleum-related activities are compatible and can be deployed concurrently (for example, CO_2 enhanced oil/gas recovery (EOR/EGR) or sequentially (for example, gas storage in depleted fields). The highest potential for conflict or competition between resources is for fluid storage or disposal, since formations suitable for natural gas and hydrogen storage would also be suitable for CO_2 storage and liquid waste disposal.

	Oil and gas	EOR/EGR	Natural gas/ H_2 storage	Deep tight gas	CO_2 storage	Usable groundwater	Geothermal
Oil and gas		C	S	C	S	D	C
EOR/EGR			S	C	C	D	
Natural gas/H_2 storage				I	S	D	
Deep tight gas					I	D	
CO_2 storage						D	C
Usable groundwater							
Geothermal							

Legend:	(dark grey)	(light grey)	(red)	(green)
	No potential	Generally low potential; unlikely	Likely to be in competition	Likely to be compatible

Figure 11. Typical concurrent and sequential uses of subsurface resources. [D: mainly at different depths; I: injectivity issues; S: sequential use potential, prioritise; C: Potential for concurrent use resources (adapted from Field *et al.*, 2017)].

In general, it is unlikely for subsurface resource development to compete with potable groundwater production because the latter is usually found at much shallower depths (like in the northern Perth Basin) and is hydraulically separated from deeper formations by sealing formations (Figure 12a). Resource development activities are more likely to compete in basins with large, contiguous sloping aquifers (for example, the Great Artesian Basin in Queensland). In the Great

Artesian Basin, usable groundwater is present at depths of more than 2 km, and deeper parts of the same aquifer are suitable for CO_2 geological storage and hydrocarbon production (similar to the configuration in Figure 12b). In this case, the state government prohibits CO_2 geological storage in the basin (*MEROLA Act 2024*) due to potential contamination of future groundwater resources. While usable groundwater aquifers are typically hydraulically separated from deeper zones through the development of other subsurface resources, resource operators need to demonstrate to the public and environmental regulators that their operations do not contaminate groundwater resources through the leakage of hazardous substances.

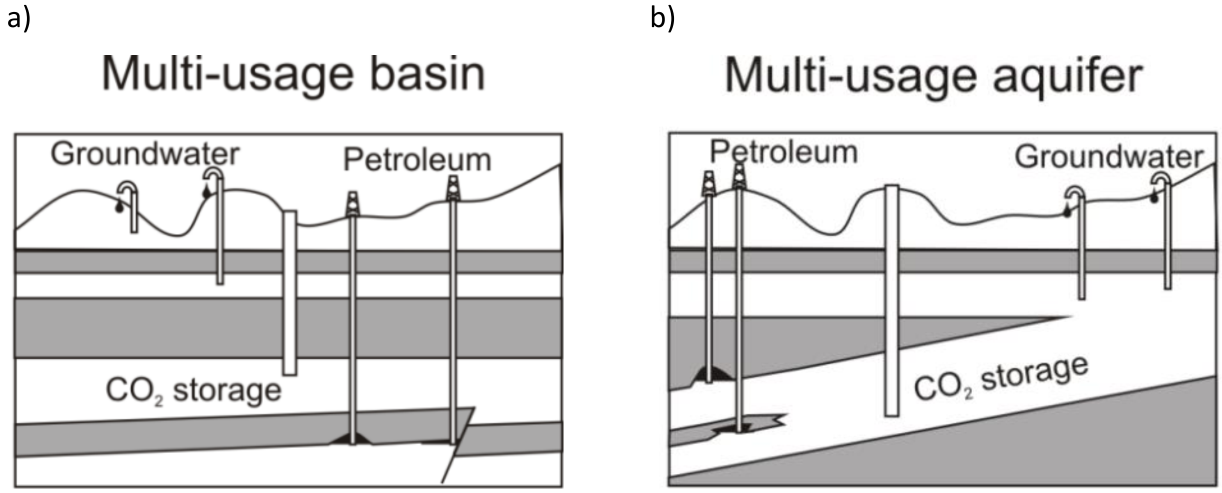

Figure 12. Illustration of a) multi-usage basin and b) multi-usage aquifer resource development scenarios (modified from Michael *et al.,* 2016).

Even if the development of different resources is compatible, complications can still occur when legislations consider commodities like natural gas and geothermal energy separately. This results in an overlap of exploration and production licenses from different owners. Guidelines and regulations need to be in place to manage the concurrent or subsequent development of these resources with minimal detrimental impacts to either party or to the environment.

The physical location and distribution of fluid in the subsurface are usually well constrained by the structural geometry of the reservoir it is contained in (for example, an oil or gas trap) or by numerically simulating the migration of an injected CO_2 plume. These fluids would need to be contained within and regulated under their respective lease areas (for example, petroleum production lease, greenhouse gas injection lease). However, pressure changes induced by fluid production or injection have a larger radius of impact (Figure 13) and could extend beyond the lease area despite decreasing away from the point of production/injection. If these pressure changes have the potential to negatively impact resource development, parties (under guidance from the regulator) would need to agree on how to measure and attribute the impacts, and how they translate into lost revenue for compensation. In the event of disagreements, the regulator may need to step in as arbitrator.

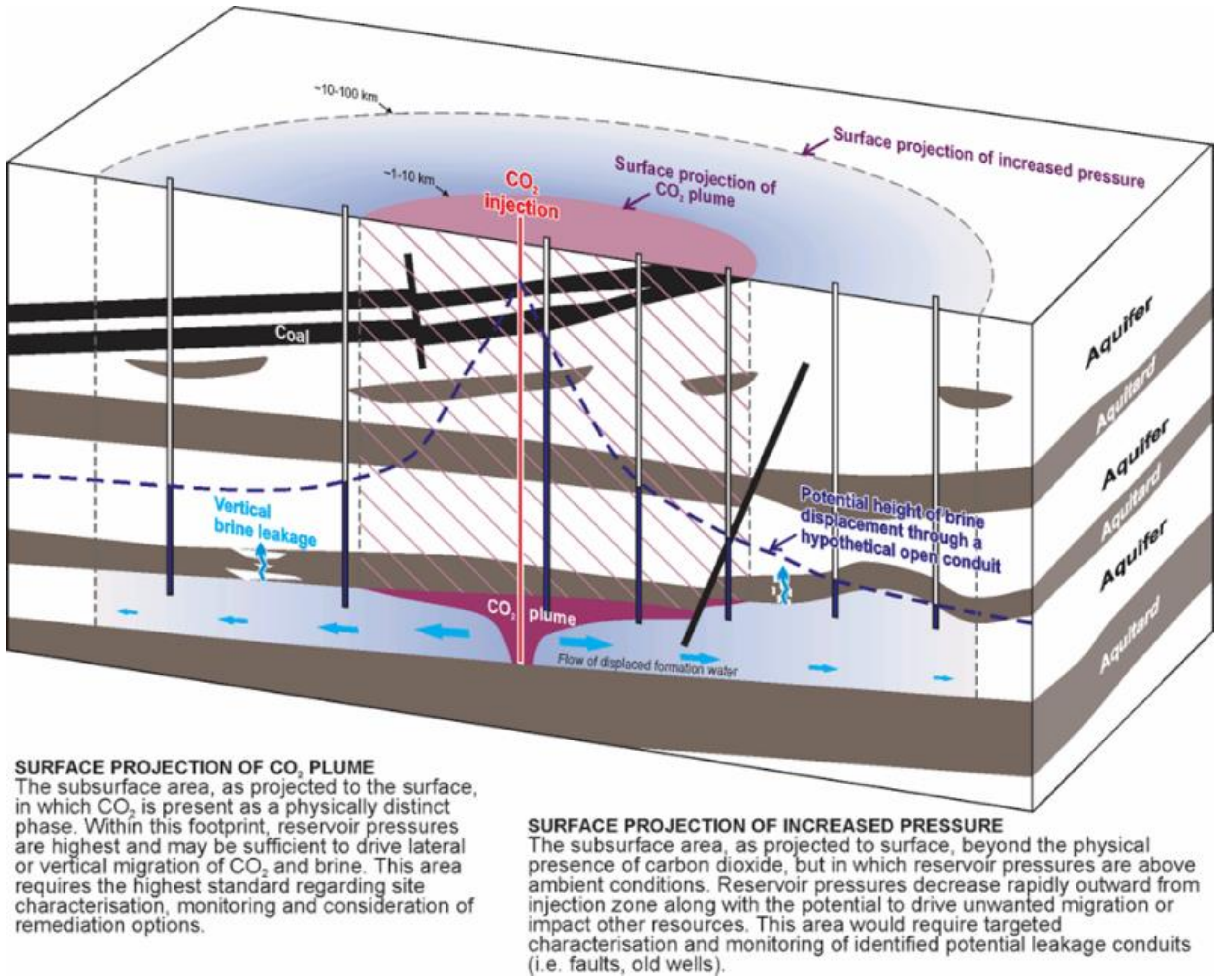

Figure 13. Schematic representation of potential impacts related to CO_2 injection (Michael *et al.,* 2016). The degree of pressure increase is reflected in the relative height of the dashed blue line, representing the potential height of displaced formation water in a hypothetical open conduit.

In a homogenous aquifer, the area of pressure change around an injection well is shaped as a cone with an exponentially increasing radius (Figure 14A). Injection pressure dissipates approximately logarithmically with distance from the well site. When there are 2 injection wells, the individual pressure cones merge, as shown in Figure 14B. In the case of fluid production, the shape of the cone would remain the same, but its direction would be inverted (in other words, pressure changes would be negative).

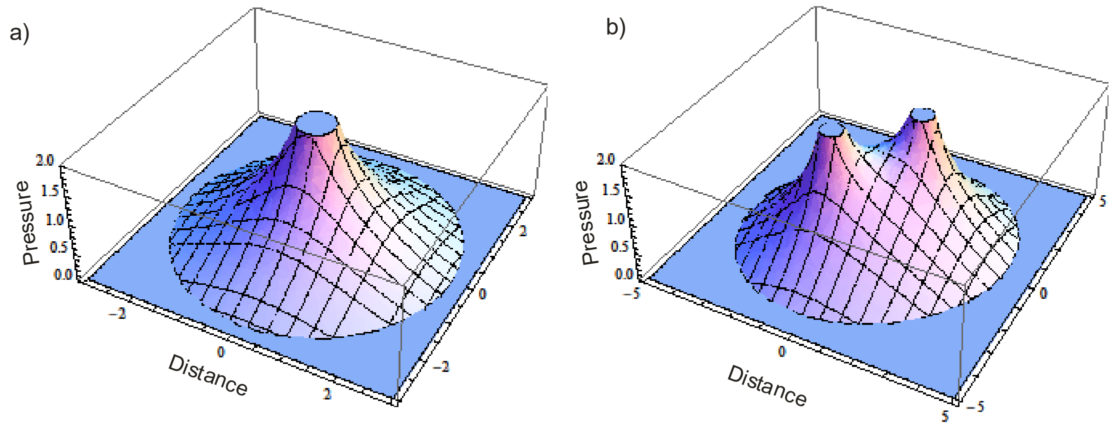

Figure 14. Steady-state pressure distribution in the vicinity of a) a well with a constant injection rate and fixed pressure at an outer radius, and b) 2 wells with equal injection rates. Axes values are dimensionless. IEAGHG (2010).

The detailed pressure distribution is governed by the injection rate, fluid viscosity, aquifer permeability, aquifer thickness, well radius and the effective reservoir radius. The pressure in bounded reservoirs (for example, fault compartments or depleted fields) with no connection to regional aquifers increases more rapidly in response to fluid injection (Figure 15). This is important because maximum allowable pressures are reached earlier in bounded reservoirs compared to unbounded reservoirs for the same injection rate and reservoir properties, hence allowing for a lower total injection volume.

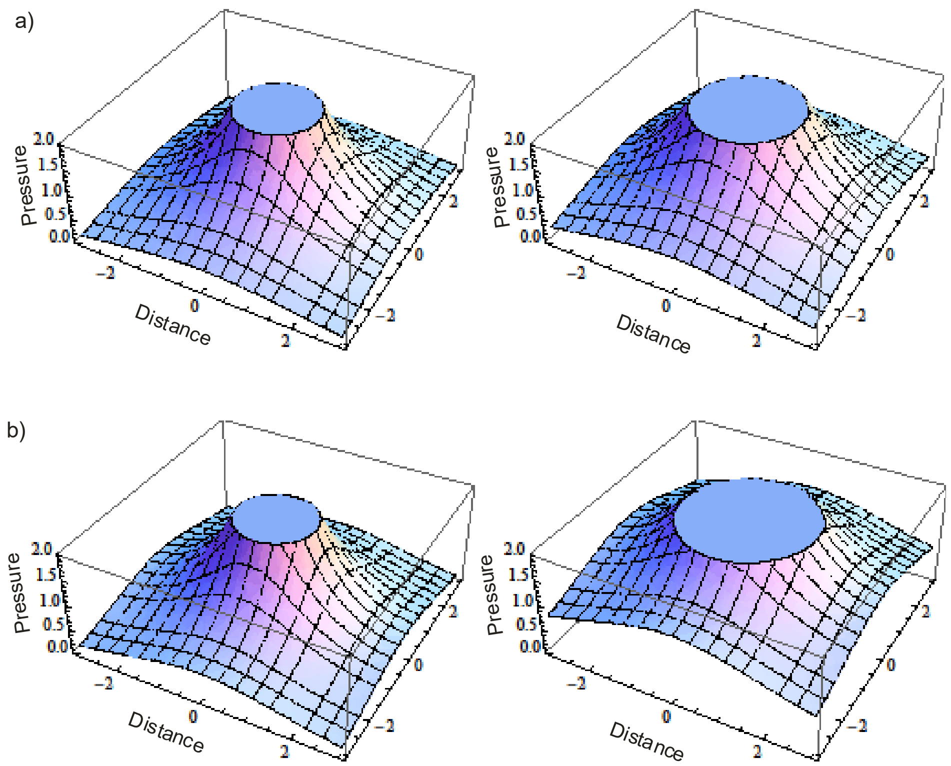

Figure 15. Pressure build-up at an early point in time (left) and later point in time (right) in a) an unbounded infinite reservoir and b) a bounded reservoir. Both a) and b) are represented at the same time steps. Pressure values are truncated at p = 2, rather than the well. IEAGHG (2010).

In sedimentary basins with multiple production and injection wells, pressure impacts are cumulative. The independent operation of CO_2 injection and petroleum production can result in significant over- or under-pressuring in a basin (Figure 16), potentially causing land uplift/subsidence, or contaminating groundwater. However, with the right development concepts, unwanted pressure changes (and associated impacts) could be significantly reduced when CO_2 injection and petroleum production are operated in conjunction (Michael *et al.,* 2013). Generally, the CO_2 storage resource for a pressure-depleted aquifer is likely to be higher than that for a normally-pressured aquifer. The difference should be related to the volumes of previous petroleum and associated water production.

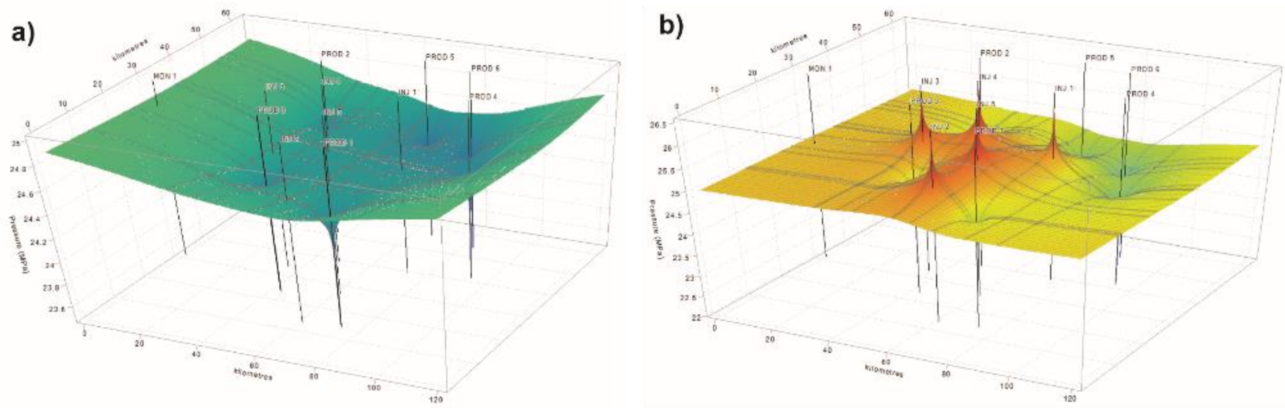

Figure 16. Results of cumulative pressure response to fluid production and injection, from basin-scale analytical simulation. The figure shows simplified models of the Gippsland Basin in Victoria, illustrating the pressure distribution in the target aquifer after fluid production for: a) 1.2 million m^3 of petroleum production, and b) concurrent petroleum production (1.2 million m^3) and CO_2 injection (2,000 Mt). Homogeneous reservoir with pre-production pressure of approximately 25 MPa. Hortle *et al.* (2014).

Basin resource management should follow a tiered approach based on how likely the impacts occur (Birkholzer *et al.,* 2014). It should focus on the degree of pressure change that could result in negative impacts on other resources. For example, the United States Environmental Protection Agency (US EPA, 2008) has proposed limiting the monitored area for a CCS project based on the minimum pressure increase at which a sustained flow of brine rises through a hypothetical conduit into an overlying drinking water aquifer occurs. Other considerations are the pressure required to reactivate faults, induce fractures in the seal, or reduce productivity of other natural resources.

1.3.1. Examples of resource conflict management from other jurisdictions

This section discusses how other jurisdictions have addressed basin resource overlap issues. While the resources in these examples are not necessarily present in the northern Perth Basin, they still provide useful insights into how other regulators respond to conflicts about the parallel development of different resources and pressure impacts.

Gas-over-bitumen (Alberta, Canada)

In Alberta, oil sands and natural gas are considered distinct commodities that can be leased separately and require separate production licenses (www.alberta.ca/gas-over-bitumen). This can be problematic when associated gas overlies a bitumen accumulation that will be exploited through an in-situ oil production process (for example, steam-assisted gravity drainage (SAGD)). SAGD involves drilling 2 wells into the bitumen zone: one well to inject steam to heat the bitumen, and the second well to recover the oil. In late 1996, the regulator, the Alberta Energy and Utilities Board (EUB), received submissions from several oil sands leaseholders with concerns that gas companies producing associated gas before bitumen production would result in potential adverse effects on the eventual recovery of bitumen. Pressure depletion in the gas reservoir could negatively impact sustained steam pressures during the SAGD process, thereby partially sterilising the bitumen resource. A subsequent hearing by the EUB established, largely based on reservoir simulation studies, that gas production could have negative impacts on SAGD in bitumen zones. While this could not be confirmed by actual data, the risk of sterilisation of valuable bitumen resources was deemed too high for all cases, and the regulator ordered the shut-in of production from 146 natural gas wells in the Surmont oil sands area in 2000, with some compensation for the gas producers (McLarty and Lepine, 2004). As a result, the *Oil Sands Conservation Act 1988* was revised in 2000 to prioritise bitumen development over natural gas production. Following the *Alberta Oil Sands Tenure Guidelines,* released in 2020, the state regulator can grant bitumen leases to existing holders of a petroleum license through a 'direct purchase' agreement outside the public offering process. This avoids 'split rights' and facilitates common ownership of subsurface resources in a specific geographic area and geological formation. The process for assessing and managing potential conflicts between natural gas and bitumen resources is depicted in Figure 17.

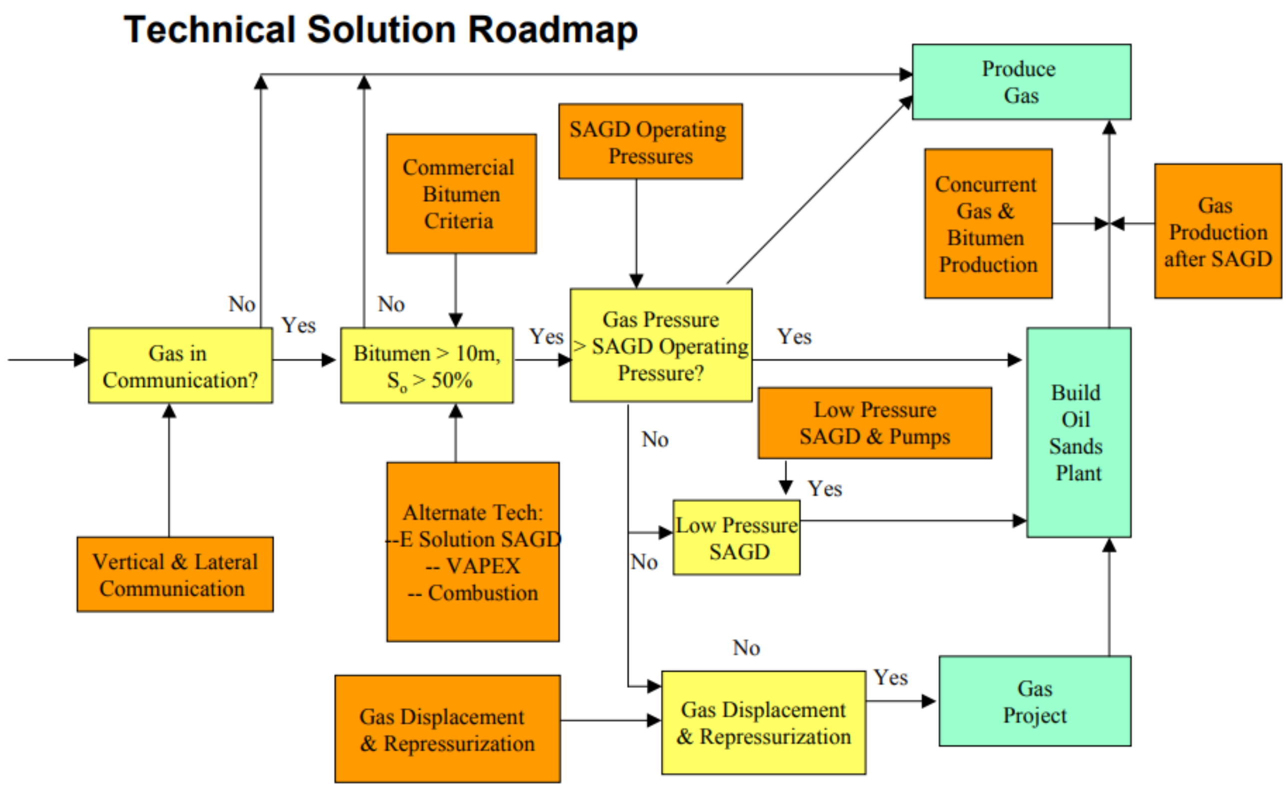

Figure 17. Flow diagram outlining a technical solution to optimise gas and bitumen recovery in Alberta, Canada. www.alberta.ca/system/files/custom_downloaded_images/gas-bit-flow-techroadmap.pdf).

Coal and coal seam gas (Queensland)

The overlap of coal mining areas and coal seam gas (CSG) production in Queensland is regulated by Chapter 4 of the *Mineral and Energy Resources (Common Provisions) Act 2014.* The Act was revised to facilitate the co-existence of Queensland's coal and CSG industries, and to ensure their cooperation to optimise the development and use of both resources (Adkins and Clague, 2014). It reflects, to a large extent, 4 principles proposed by the industry in a white paper:

1. **Direct path to grant:** Providing all other requirements are satisfied, an application for a production license can be granted without requiring ministerial preference decision, even if it overlaps with an existing exploration or production tenure for another resource.
2. **Right of way for coal:** The rights of a CSG tenure holder can be temporarily suspended within pre-determined areas of a coal mining lease, where sole occupancy is required for safe and efficient coal mining operations.
3. **Information exchange:** To optimise the co-development of coal and CSG resources.
4. **Freedom to negotiate bespoke agreements.**

The Act provides a framework for independent arbitration in the case of disputes (for example, acceleration notices given by a coal mining operator, compensation payments, changes to joint development plans, etc.). Two industry experts with coal and CSG expertise must be involved in the arbitration process, and the arbitrator's decision must be consistent with mining safety and health requirements. It must also result in the optimal development of coal and CSG resources.

For groundwater impacts on petroleum activities, the Queensland *Water Act 2000* defines trigger thresholds for production-induced pressure impacts. These thresholds are set as 5 m and 2 m hydraulic-head drawdown for consolidated (i.e. sandstone) and unconsolidated aquifers (i.e. sand), respectively. The responsible petroleum tenure holder must conduct an impact assessment that identifies boreholes of other users within the affected area and enter into an agreement with the owners of those bores.

CO_2 geological storage and groundwater (Great Artesian Basin, Queensland)

In 2020, the Carbon Transport and Storage Company (CTSCo), a subsidiary wholly owned by Glencore, started exploration and appraisal of a greenhouse gas storage permit (EPQ7) in the Surat Basin, under Queensland's *Greenhouse Gas Storage Act 2009*. CTSCo submitted a first draft of their Environmental Impact Statement (EIS) in 2022 to support a test CCS project, which proposed to inject up to 330,000 tonnes of CO_2 from Glencore's Millmerran Power Station into the Precipice Sandstone in the Surat Basin over 3 years, at a depth of approximately 2300 m. While not potable, formation water at that location in the Precipice Sandstone is relatively fresh, with a salinity of approximately 4000 mg/l. Approximately 60 km to the west, oil is produced from updip in the Precipice Sandstone at a depth of ~ 1200 m and 3000 mg/l salinity. Following objections from landholders in the region, who were concerned about future use of Precipice water as stock water, various independent technical experts and organisations reviewed the EIS and a final amended EIS was submitted to the regulator in March 2024. Ultimately, the Minister rejected CTSCo's proposal based on Section 41 of Queensland's *Environmental Protection Regulation 2019*, on the basis that CO_2 is considered a 'waste', and CTSCo's injection target, the Precipice Sandstone, is not a 'confined aquifer' (defined as contained entirely within impermeable strata).

As a result, injected CO_2 was likely to deteriorate the environmental values of the receiving groundwater.

Queensland Environmental Protection Regulation 2019, Section 41: Activity involving direct release of waste to groundwater.

(1) This section applies to the administering authority for making an environmental management decision relating to an activity that involves, or may involve, the release of waste directly to groundwater (the receiving groundwater). Example of direct release of waste to groundwater – an activity involving the release of contaminated water to groundwater through a well, deep-well injection or a bore

(2) The administering authority must refuse to grant the application if the authority considers:

> **(a) for an application other than an application relating to an environmental authority for a petroleum activity – the waste is not being, or may not be, released entirely within a confined aquifer; or**
>
> **(b) the release of the waste is adversely affecting, or may adversely affect, a surface ecological system; or**
>
> **(c) the waste is likely to result in a deterioration in the environmental values of the receiving groundwater.**

(3) In this section, confined aquifer means an aquifer that is contained entirely within impermeable strata.

While initial concerns regarding CO_2 storage in the Great Artesian Basin were largely economic (for example, the contamination or sterilisation of a future water source for cattle farmers and agricultural use), it was the enactment of Queensland's environmental legislation that rejected CTSCo's CO_2 storage project. Consequently, legislative changes through the *Mineral and Energy Resource and Other Legislation Amendment Act 2024* (MEROLA Act 2024) were introduced to permanently ban all greenhouse gas storage and injection activities in Queensland's Great Artesian Basin with the aim "…to protect its unique environmental, social, economic, and cultural values from the potential safety and environmental risks posed by carbon dioxide injection."

Lessons learned

The examples from Alberta and Queensland show different ways of managing the co-development of, and potential conflicts between, various subsurface resources. Each example is based on different drivers that lead to varying forms of prioritisation (Table 2).

Table 2. Summary of resource conflict examples.

Case	Resources	Conflict type	Resolution	Basis	Outcome
Alberta gas over bitumen	Oil from bitumen – natural gas	Pressure communication	Prioritisation of more valuable oil resource	Economics	Natural gas can only be produced after development of bitumen resource
Queensland coal-CSG	Coal – coal seam gas	development of vertically separated resources in overlapping leases;	Co-existence of both resource developments; 'right of way' for coal	Economics/ safety	Both resources can be developed in parallel, but CSG production may be temporarily suspended/delayed (with compensation provisions) if it prevents safe coal mining
Queensland CO_2 storage	CO_2 storage – water resources	Direct contact, contamination of water resource	Prioritisation of future water resource	Environmental/ social	Ban of CO_2 geological storage in the Great Artesian Basin

In Alberta's gas-over-bitumen and Queensland's coal-CSG examples, the management of resource development is largely informed by economics. Oil produced from bitumen is considered to have higher value than natural gas, now and in the foreseeable future. As gas production (whether before or during) may be detrimental to bitumen development, the latter is clearly prioritised under the current regulations in Alberta. However, the priorities could change if natural gas becomes more valuable in the future.

In Queensland, coal and CSG are considered equally important for the state's economy and regulations attempt to enable co-development of the 2 resources in the most efficient and safe way.

The Great Artesian Basin is a special case, because the conflict between geological storage of CO_2 and water resources is not purely based on economics, but also on environmental and social aspects. Although the groundwater in question is not potable and located at depths too deep to be economically produced at present, CO_2 geological storage was deemed too risky due to potential contamination of a future water resource for cattle farming. The development of coal, CSG and other petroleum resources also falls under environmental regulations and cannot have detrimental effects on potable groundwater or other environmentally sensitive areas.

One advantage of having a clear ban or prioritisation of one resource over the other is that it provides certainty, avoiding lengthy and costly arbitration hearings. However, economics and priorities can change, which may require an update of regulations in the future.

Generally, direct impacts (like contamination of one resource by the operations of another) are relatively easy to identify. Compensation can be paid based on lost revenue if the impacts are impossible to mitigate. Pressure impacts, on the other hand, are harder to predict and more difficult to attribute to a source. They are not necessarily detrimental, and may even be favourable. Again, having clear trigger values provides certainty and helps parties agree on monitoring and compensation solutions before any conflict arises (for example, the 5 m and 2 m hydraulic-head values in Queensland for acceptable drawdown induced by CSG production in a neighbouring well). This works particularly well when the pressure impact is detrimental, such as in cases where both parties rely on pressure reduction (or pressure increase) for developing their respective resources.

1.4. Regulatory environment in Western Australia

1.4.1. Western Australian groundwater legislation and regulations

In Western Australia, the Department of Water and Environmental Regulation (DWER) is responsible for water planning, management and quality protection. The *Rights in Water and Irrigation Act 1914* provides the statutory basis for planning and allocation of water in Western Australia. The objectives of the legislation include the management, sustainable use and development of water resources to meet the needs of current and future users, as well as the protection of ecosystems and the environment in which water resources are situated. DWER approves different types of licences and permits to authorise various activities related to groundwater abstraction, including:

a) a licence to take groundwater or surface water

b) a licence to construct or alter a groundwater well.

The *Country Areas Water Supply Act 1947* provides for the allocation of reticulated water to country areas and safeguards water supplies. The *Metropolitan Water Supply, Sewerage and Drainage Act 1909* provides the legal definition of boundaries for metropolitan water, sewerage and drainage areas. The Acts define legal boundaries of surface and groundwater drinking water sources and include bylaws that protect the water quality of these sources. They also include provisions for the establishment of protection zones (for example, wellhead protection zones and reservoir protection zones). Any intention to take groundwater or inject into aquifers is covered under the above 3 Acts. Occasionally, DWER develops specific management plans that further define the circumstances under which water can be taken from an aquifer, and guidelines for the protection of water resources from any activity that has the potential to affect their quality.

The responsibility for the public water supply in Western Australia lies with the various water service providers, which in the case of the northern Perth Basin, is the Water Corporation.

1.4.2. Environmental assessment and regulatory system

The regulatory and policy requirements of the resources sector (including minerals, petroleum, geothermal and geological storage of natural gas, hydrogen and carbon dioxide) are overseen by the Resource and Environmental Regulations Group in the Department of Energy, Mines, Industry Regulation and Safety (DEMIRS) of the Western Australian Government.

The legal framework for the exploration and recovery of petroleum in Western Australian onshore and State waters areas is provided within the *Petroleum and Geothermal Energy Resources Act*

1967 (PGER) and the *Petroleum (Submerged Lands) Act 1982*. 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:

- 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 Petroleum and Geothermal Energy Resources (Environment) Regulations 2012
- the Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015 (the 'onshore' regulations) and the Petroleum (Submerged Lands) Resource Management and Administration) Regulations 2015.

DEMIRS assesses environmental proposals for petroleum and geothermal energy resources in accordance with the *Petroleum and Geothermal Energy Resources Act 1967*, and the *Mining Act 1978* for mining-related activities. Mining, petroleum and geothermal activity proposals that may have a significant environmental impact will be referred to the Environmental Protection Authority (EPA) for environmental impact assessment under the *Environmental Protection Act 1986*.

The Western Australian Environmental Protection Authority (WA EPA) is an independent entity, and its operations are governed by the Environmental Protection Act 1986. WA EPA's functions include:

- conducting environmental impact assessments
- preparing statutory policies for environmental protection
- preparing and publishing guidelines for managing environmental impacts
- providing strategic advice to the Minister for Environment.

Overlapping petroleum, geothermal (and carbon storage) titles

Under the PGER Act 1967, petroleum and geothermal titles can exist under the same title block. In June 2023, DEMIRS published a draft of the 'Guide note on the management of subsisting petroleum and geothermal titles,' containing the following assessment considerations and principles:

1. Prior to making an application, either as part of an acreage release or for a Special Prospecting Authority (SPA), applicants should undertake the following:
    1. Make themselves aware of any existing petroleum or geothermal title.
    2. Be aware that proposals for work may be restricted due to potential impacts on existing operations. Applicants should identify any potential impacts and demonstrate how these are to be mitigated or managed.
    3. Demonstrate that the proposed work program and expenditure are achievable without interference with subsisting titles or rights, or potential excluded areas.
    4. Note that in the case of applications received as part of an acreage release, work programs cannot be changed by the applicant post-bid; however, the Minister may approve an alternative work program.

2. The following principles will be applied when assessing tenure applications that would create subsisting petroleum or geothermal titles:
    a. Avoidance of potential impacts to existing recovery operations and declared locations will be prioritised over exploration operations and leads or prospects.
    b. Discovered resources are given priority over prospective resources.
3. To assess potential impacts when assessing applications that subsist with existing petroleum or geothermal titles, DEMIRS will follow this process (Figure **18**):
    a. Identify potential impacts to existing petroleum or geothermal recovery and exploration operations.
    b. Review information about the mitigation or management of impacts submitted as part of the application.
    c. If appropriate, request that the applicant provide further information regarding any potential impacts. Whilst not exhaustive, this may include requests for:
        i. a description of discovered petroleum pools or geothermal energy resources within subsisting titles, or where there may be an impact on another title
        ii. the outcomes of any consultations undertaken with existing title holders
        iii. whether the applicant intends to explore in the same geologic intervals as any declared locations, petroleum pools or geothermal energy resources within subsisting titles or another title.
    d. DEMIRS may also seek information from existing petroleum or geothermal title holders on what they consider to be potential impacts on their operation, and how these might be mitigated or managed best.
    e. DEMIRS' assessment will consider:
        i. the degree to which the proposed exploration (as per the proposal for work and expenditure) or recovery operations interfere with exploration or recovery operations in subsisting petroleum or geothermal titles
        ii. where applicable, how the proposed work program demonstrates that the extraction of petroleum or geothermal energy will not affect the extraction of the other in future.

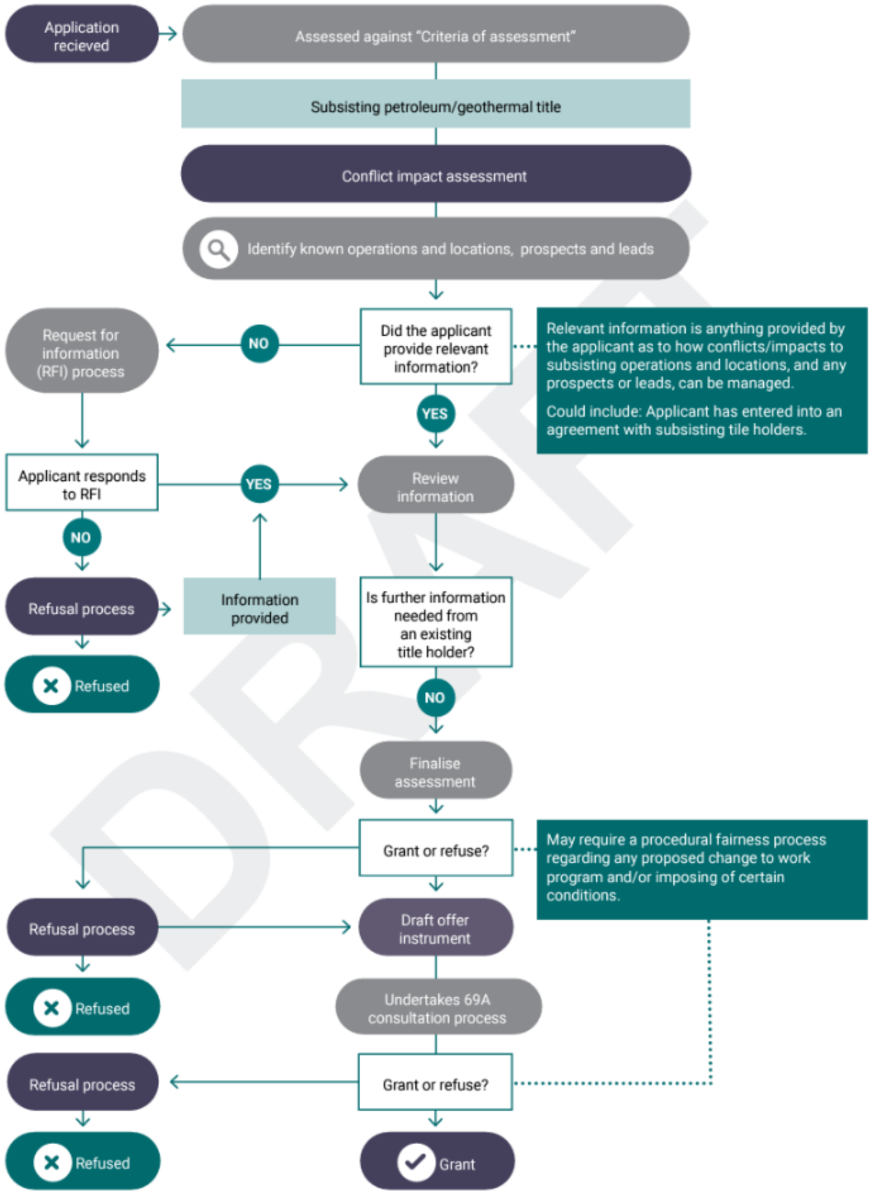

Figure 18. Draft schematic workflow of the assessment process for subsisting petroleum or geothermal titles (DEMIRS, 2023).

CO_2 geological storage

In May 2024, the Carbon Capture and Storage Bill (an amendment to the *Petroleum and Geothermal Energy Resources Act 1967*, *Petroleum Pipelines Act 1969 and Petroleum (Submerged Lands) Act 1982*) passed Western Australian Parliament. This amendment provides a legislative framework for the transport and geological storage of greenhouse gases, and it also enables exploration for naturally occurring hydrogen. Regulations associated with this Bill are currently under development and are needed before any activity related to carbon geological storage or natural hydrogen can commence.

Regulations and guidelines are currently being updated under the *Petroleum Legislation Amendment Bill (B) 2023* to include subsisting titles for geological storage of CO_2 and natural hydrogen activities in a similar way as for petroleum and geothermal titles. In *Response to Submissions Petroleum Legislation Amendment Bill (B) 2023*, DEMIRS proposes that petroleum and geothermal lessees and licensees will be able to apply for a greenhouse gas retention lease or a greenhouse gas injection license, without going through the acreage release process. This will avoid the delay of greenhouse gas storage projects. However, this greenhouse gas lease cannot extend beyond the blocks of the existing petroleum or geothermal license areas. Petroleum and geothermal permittees, and holders of petroleum and geothermal drilling reservations, will not be eligible to make an application for a greenhouse gas retention lease to minimise the risk of 'land banking'. Land banking refers to the practice of acquiring undeveloped land, often in areas with potential for future development, with the goal of selling it later at a higher price.