# 3. Northern Perth Basin resources

## 3.1. Petroleum resources

The northern Perth Basin is the second highest petroleum-producing province under Western Australian jurisdiction, following the Northern Carnarvon Basin in the state's territorial waters. The description below is based on information from DEMIRS (2024), Geoscience Australia (2020 and 2023), and Mory and Iasky (1996).

Petroleum-system analysis indicates the presence of widespread mature source rocks, abundant reservoirs, and favourable timing of structures for hydrocarbon entrapment. However, seal integrity is considered the biggest uncertainty due to the intense faulting and high sand-to-shale ratio of the post-Lower Triassic succession. Major play types in the basin include Permian-Triassic and Jurassic anticlines, Permian-Triassic tilted fault blocks and stratigraphic traps. Viable deeper plays (for example, Lower Permian) also exist, as evidenced by the Waitsia gas field. While oil and gas production have declined as fields deplete, deep gas resources have the potential to offset this decline.

Four petroleum systems have been identified within the northern Perth Basin (Figure 5):

1. Gondwanan 1 with a Permian source
2. Gondwanan 2 with a mostly Triassic source
3. Austral 1 with Jurassic sources
4. Austral 2 with an Upper Jurassic-Lower Cretaceous source.

### 3.1.1. Petroleum system elements

These petroleum systems are composed of key geological elements—source rocks, reservoirs, seals, traps, and generation histories—that together determine the location and productivity of hydrocarbon accumulations. The following summaries highlight the main components and their distribution.

Sources:

- Permian: Gas-prone shales and coals, particularly the Irwin River Coal Measures (IRCM) and Carynginia Formation, are sources of gas.
- Triassic: Oil- and gas-prone marine shales, notably the Kockatea Shale, especially the Hovea Member, serve as primary oil sources.
- Jurassic: Marine and non-marine oil-and gas-prone shales and coals from formations like the Eneabba Formation, Cattamarra Coal Measures, and Cadda Formation.

Reservoirs:

- Permian: Fluvio-deltaic and marine sandstones, including the High Cliff Sandstone and Dongara Sandstone, provide significant reservoir potential.

- Triassic: Shallow marine sandstones, notably from the Woodada Formation and Lesueur Sandstone, serve as reservoirs.
- Jurassic: Fluvial and deltaic sandstones from the Cattamarra Coal Measures and Yarragadee Formation provide reservoir potential.

Seals:

- Regional seals: Marine shales of the Triassic Kockatea Shale and the Jurassic Cadda Formation provide regional sealing capabilities.
- Intraformational seals: These are present throughout the Triassic-Jurassic interval, ensuring containment within various stratigraphic levels.

Traps:

- Structural: Large stratigraphic pinch-outs, fault block plays, and rollover anticlines are common. Sub-unconformity plays also exist, particularly under the Valanginian unconformity.

Generation:

- Permian source rocks generated significant amounts of gas, with peak generation occurring in the Triassic interval.
- The Hovea Member of the Kockatea Shale entered the main oil window in the Triassic, with maturity increasing during the Jurassic and Early Cretaceous interval.
- Oil and gas expulsion from Jurassic source rocks occurred primarily in the Early Cretaceous interval, with additional generation and expulsion from multiple source rocks after Valanginian break-up.

### 3.1.2. Petroleum wells and infrastructures

The northern Perth Basin hosts 355 petroleum wells, 18 gas pipelines and 6 petroleum facilities, most of which are dedicated to production (Figure 23).

### 3.1.3. Petroleum fields and permits

The northern Perth Basin includes 48 petroleum fields (Figure 24) across a range of operational states and development stages. There are 13 fields (27.1%) currently shut-in, which are not producing hydrocarbons but are maintained for potential future use. Five fields (10.4%) are actively producing hydrocarbons. Twenty-three fields (47.9%) are undeveloped, meaning they have been discovered but not yet developed for production. Additionally, 7 fields (14.6%) are depleted, having exhausted their economically recoverable hydrocarbons.

The northern Perth Basin includes 53 petroleum permits (Figure 25).

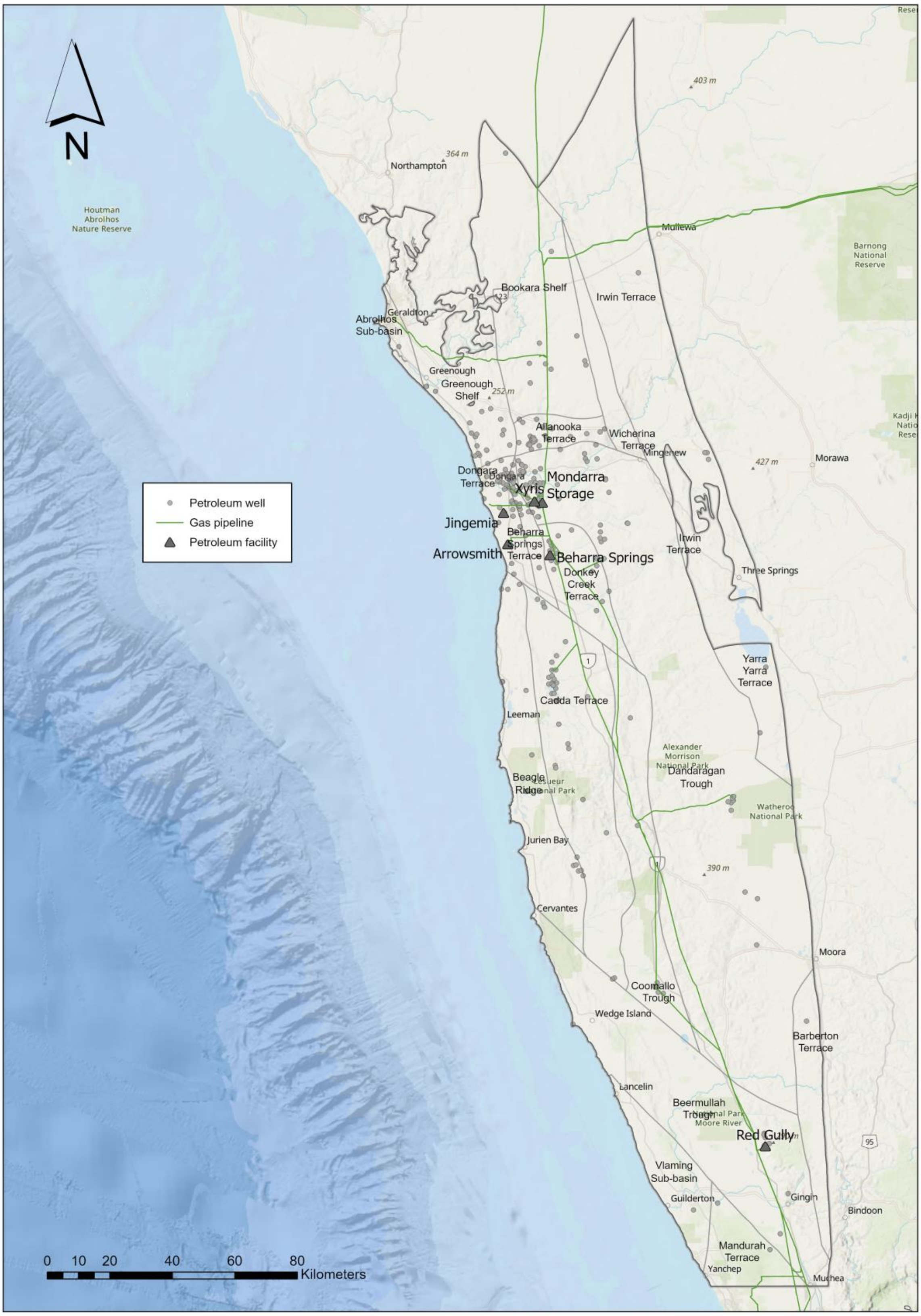



**Figure 23. Petroleum wells, gas pipelines and petroleum facilities in the northern Perth Basin.**

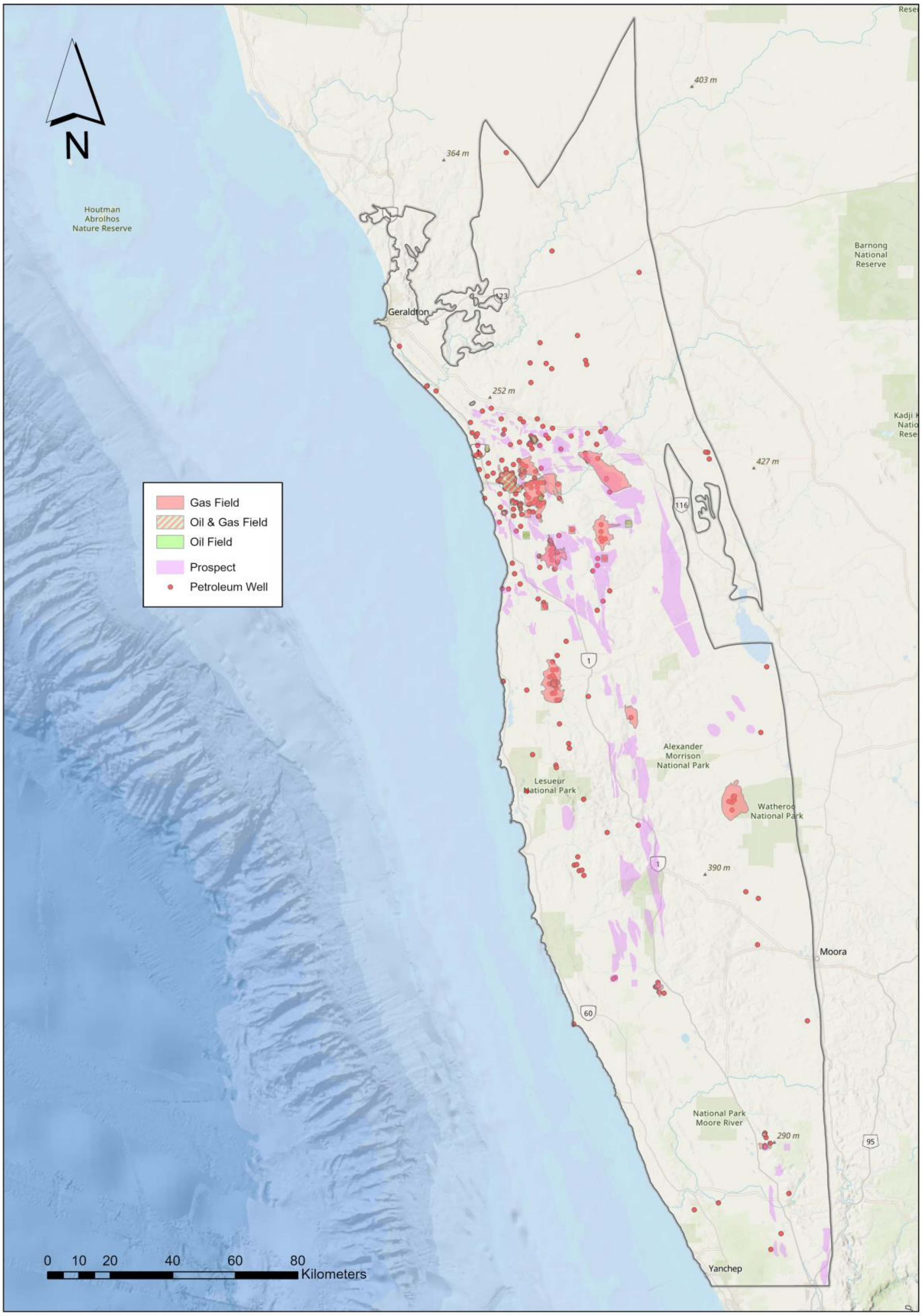



**Figure 24. Petroleum fields and prospect distribution in the northern Perth Basin.**

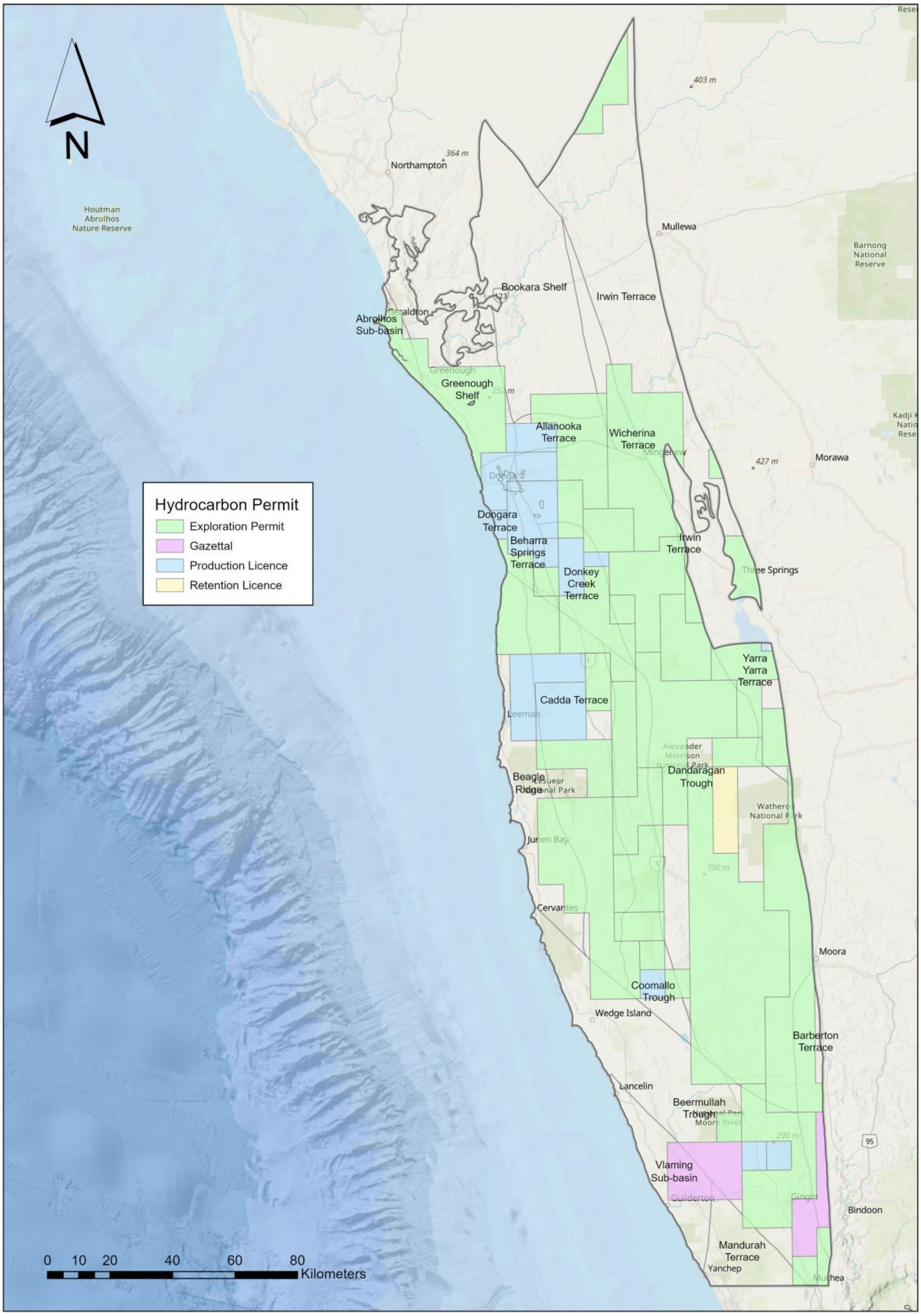



Figure 25. Petroleum permits distribution in the northern Perth Basin.

### 3.1.4. Natural hydrogen

Hydrogen has been detected in petroleum well samples across the northern Perth Basin, with reported concentrations reaching tens of percent (Haines, 2023). However, the source, migration and trapping mechanisms of natural hydrogen remain highly uncertain (for example, Stalker *et al.,* 2022 and Langhi, 2024). It is unclear whether the hydrogen detected in wells originates from natural subsurface generation processes or is an artifact of drilling or operational conditions (Langhi and Strand, 2023).

Unlike petroleum systems, where the source, migration pathways and trapping mechanisms are relatively well understood, the dynamics of natural hydrogen generation, movement, and containment in the subsurface remain largely uncharacterised. Current evidence suggests that the hydrogen is mixed with hydrocarbon accumulations, implying that it may not form independent, conventional accumulations. The potential caprock effectiveness for hydrogen retention is also unknown, adding further uncertainty to its long-term containment (Stalker *et al.,* 2022).

Given these uncertainties and knowledge gaps, no suitability map can or should be applied at this stage. Under the current state of understanding, the most reasonable assumption is that if a natural hydrogen resource exists in the northern Perth Basin, it would behave similarly to petroleum: trapped within conventional porous reservoirs and sealed by low-permeability caprocks. Until further data and research provide a clearer understanding of its generation, migration and accumulation mechanisms, natural hydrogen must be treated as a potential but unconfirmed subsurface resource that shares fundamental geological principles with conventional hydrocarbons.

## 3.2. Geothermal resources

### 3.2.1. Background: geothermal energy

Geothermal energy is a low-emissions resource that can be exploited for direct use or to generate electricity, depending on the temperature of the geothermal operation's target depth (Figure 26, left).

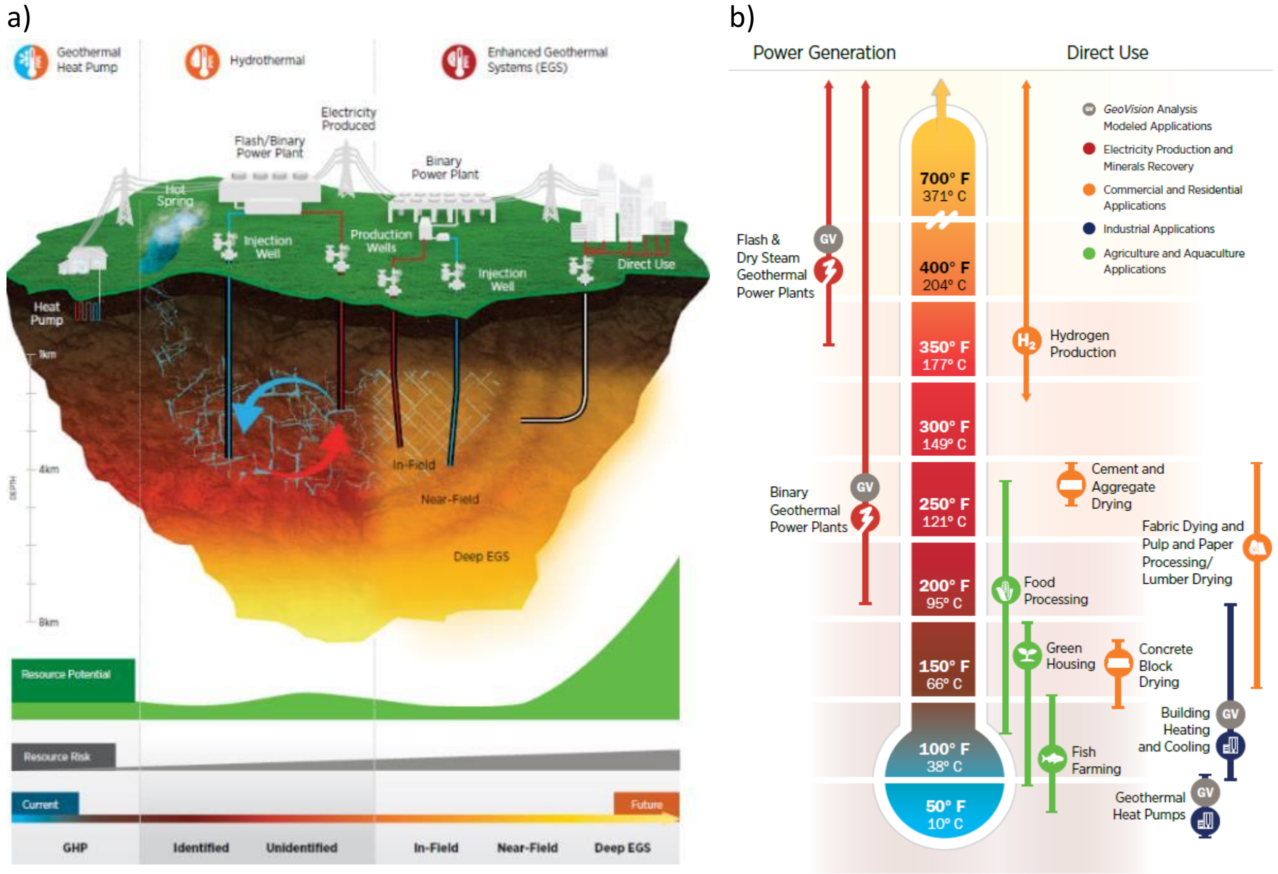



**Figure 26. a) Application types for geothermal resources and b) temperature ranges for typical use of geothermal resources (US DOE, 2019).**

While there is a large variety of geothermal energy systems, all have 3 basic components (Huddlestone-Holmes, 2014):

a) the geothermal resource (the heat)

b) the method with which this heat is accessed

c) the component that uses the heat.

#### Geothermal resource

The primary aspect of a geothermal resource is heat, originating from deep within the Earth and trapped by insulating rocks. In addition, a fluid (such as water or steam) that can easily flow through the rock must be present to develop the geothermal resource. This fluid may be naturally occurring or introduced into the system.

### Heat access

The heat energy in a geothermal resource is accessed through wells drilled into the geothermal reservoir. The heat is delivered to the surface in the form of a fluid (water or steam) through production wells. After extracting the heat, cool water may be reinjected through a nearby second well, where it is heated before it is produced again through the first production well. Such a loop can be either open (where fluid flow occurs through the reservoir rock) or closed (where fluid is circulated within a connected pair of wells, without contacting the reservoir rock).

### Heat utilisation

At the surface, energy is extracted from the hot fluid through a power station. Alternatively, the heat can be used directly for district heating or other industrial processes.

Commercial electricity generation is generally economical at temperatures above 150°C and at depths that can be accessed by wells providing adequate flow. New technologies, such as binary plants, are being developed that use working fluids with a lower boiling temperature than water and can produce electricity at lower temperatures. The direct use of geothermal energy has a wide range of applications, including the heating of greenhouses, swimming pools and buildings, at temperatures ranging from ~ 20–140°C. (Figure 26, right).

Western Australia primarily explores 2 types of geothermal technologies for electricity generation (Figure **27**):

- **Hot sedimentary aquifers (HSA):** these systems utilise naturally occurring hot water found in porous rocks at depths of 1–4 km.
- **Enhanced geothermal systems (EGS):** these systems extract heat by circulating fluids through engineered fractures in hot dry rocks found at depths of 3–5 kilometres, but their commerciality is yet to be demonstrated. This technology is particularly suited to parts of Australia that are not covered by sedimentary basins and exhibit high heat flow.

In addition to these, direct use systems leverage the Earth's natural heat for non-electric applications, like heating and cooling buildings. This method is utilised in some residential developments and public swimming pools, providing an efficient and sustainable heating solution.

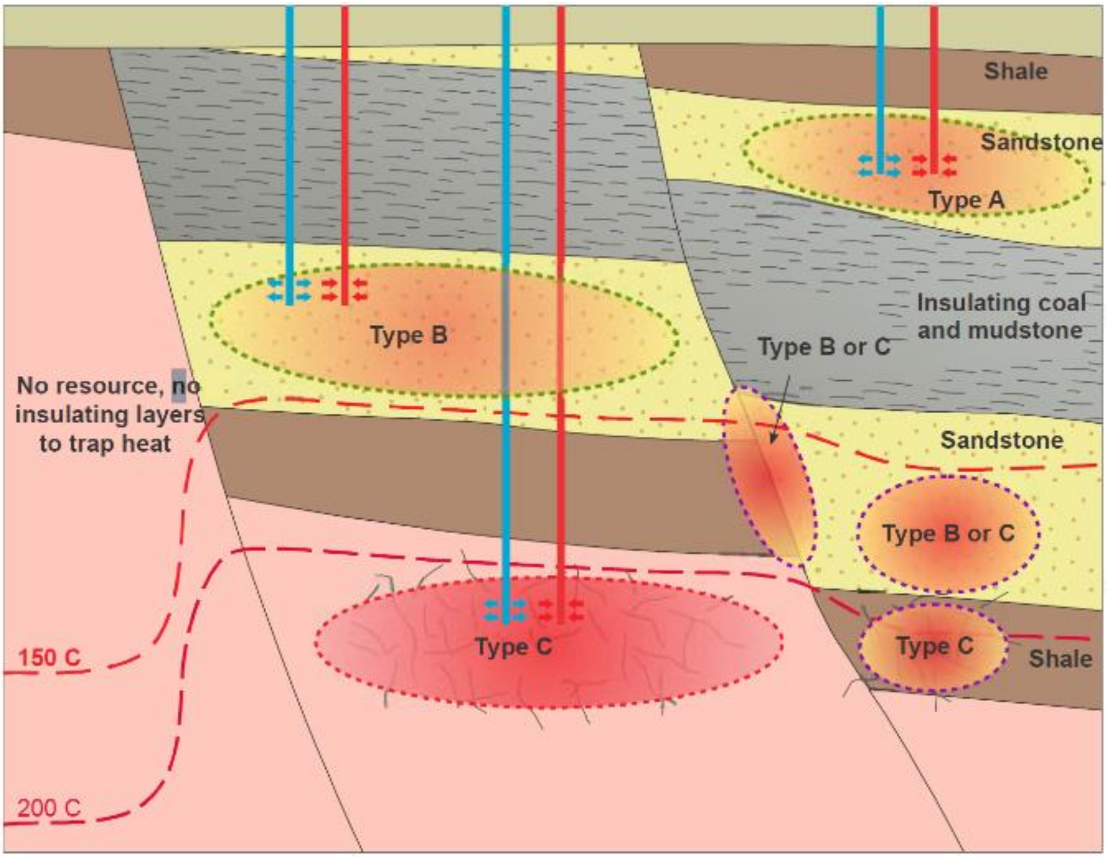



**Figure 27. Schematic representation and hypothetical geological settings of different geothermal resource styles as a function of depth (approximates temperature) and enhancements required to produce the required flow rates. 'Type A' represents shallow, direct use; 'Type B' represents hot saline aquifer (HSA); and 'Type C' represents EGS. Huddlestone-Holmes (2014).**

### 3.2.2. Northern Perth Basin heat flow and geothermal reservoirs

The northern Perth Basin exhibits a range of heat flow values and geothermal gradients, reflecting its complex geological structure. The heat flow values range from 30 to 140 mW/m² (Ghori, 2009), with higher values observed in the northwest where the sedimentary section is thinner. In contrast, lower values are present in the eastern part over the Dandaragan Trough.

The average geothermal gradient in the northern Perth Basin ranges between 10 to 55 °C/km (Mory and Iasky, 1996). However, greater depths show less consistent gradients due to the basin's complex geological structure. Both conductive and convective heat transport mechanisms are present, with conductive being predominant.

Key formations within the Perth Basin that hold potential as geothermal reservoirs include granitic basement rocks and sedimentary layers with high porosity and permeability. Specific formations of interest are those intersected by petroleum exploration wells, which have high temperature gradients and suitable reservoir properties. The focus is on shallower depths (2.5–3.5 km) with temperatures of 150–160 °C and adequate fluid flow rates from natural faults and fractures.

Figure 28 shows the temperature at the top of the Kockatea Shale (and equivalent strata) as well as the location of geothermal titles and applications in the northern Perth Basin.

The Kingia Sandstone (Figure 29) stands out as a key formation for geothermal energy (Ballesteros *et al.,* 2020) due to its favourable heat flow and temperature characteristics:

- **Heat flow:** Exceeds 90 $mW/m^2$ locally.
- **Geothermal gradient:** Approximately 37 °C/km.
- **Aquifer temperatures:** Exceeds 115 °C, making it suitable for power generation using binary Organic Rankine Cycle (ORC) technology.
- **Depth and temperature:** Temperatures can exceed 150 °C at depths generally greater than 3500 m.
- **Fluid flow rates:** While there is current gas production from Kingia Sandstone reservoirs, permeability values are not well constrained. Additionally, there is large uncertainty around the presence of permeability sufficient for maintaining fluid flow rates adequate for geothermal applications.

The Kingia Sandstone is distributed on the Dongara Terrace, Beharra Spring Terrace, Dandaragan Trough, Donkey Creek Terrace, Beagle Ridge, Cadda Terrace and Coomallo Trough, with the hotter part located on the Cadda Terrace, Donkey Creek Terrace and Dandaragan Trough.

Other formations reach temperatures exceeding 150°C, mostly at depths greater than 4000 m.

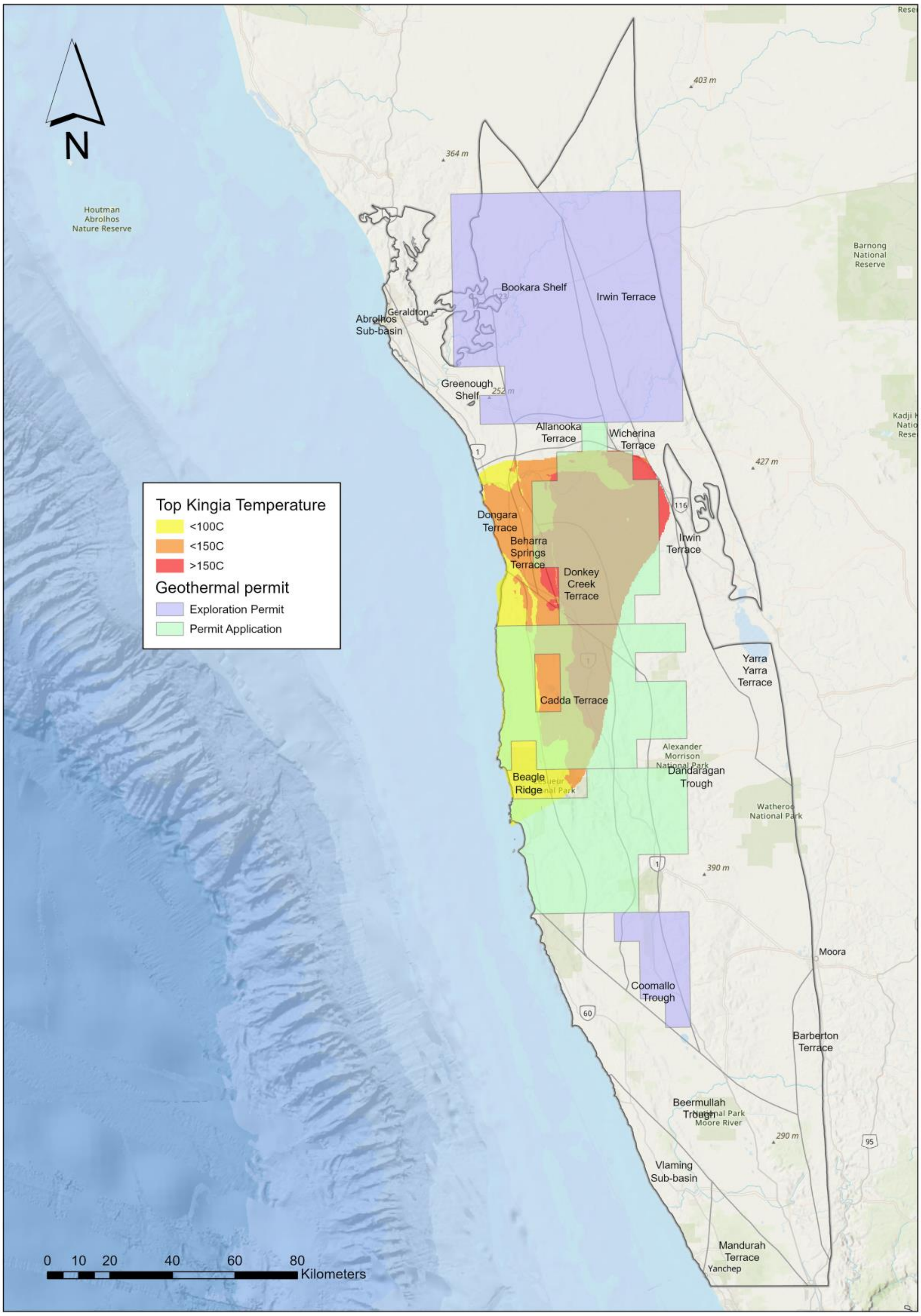



**Figure 28. Temperature at the top of the Kockatea Shale (and equivalent strata) and location of geothermal titles and applications.**

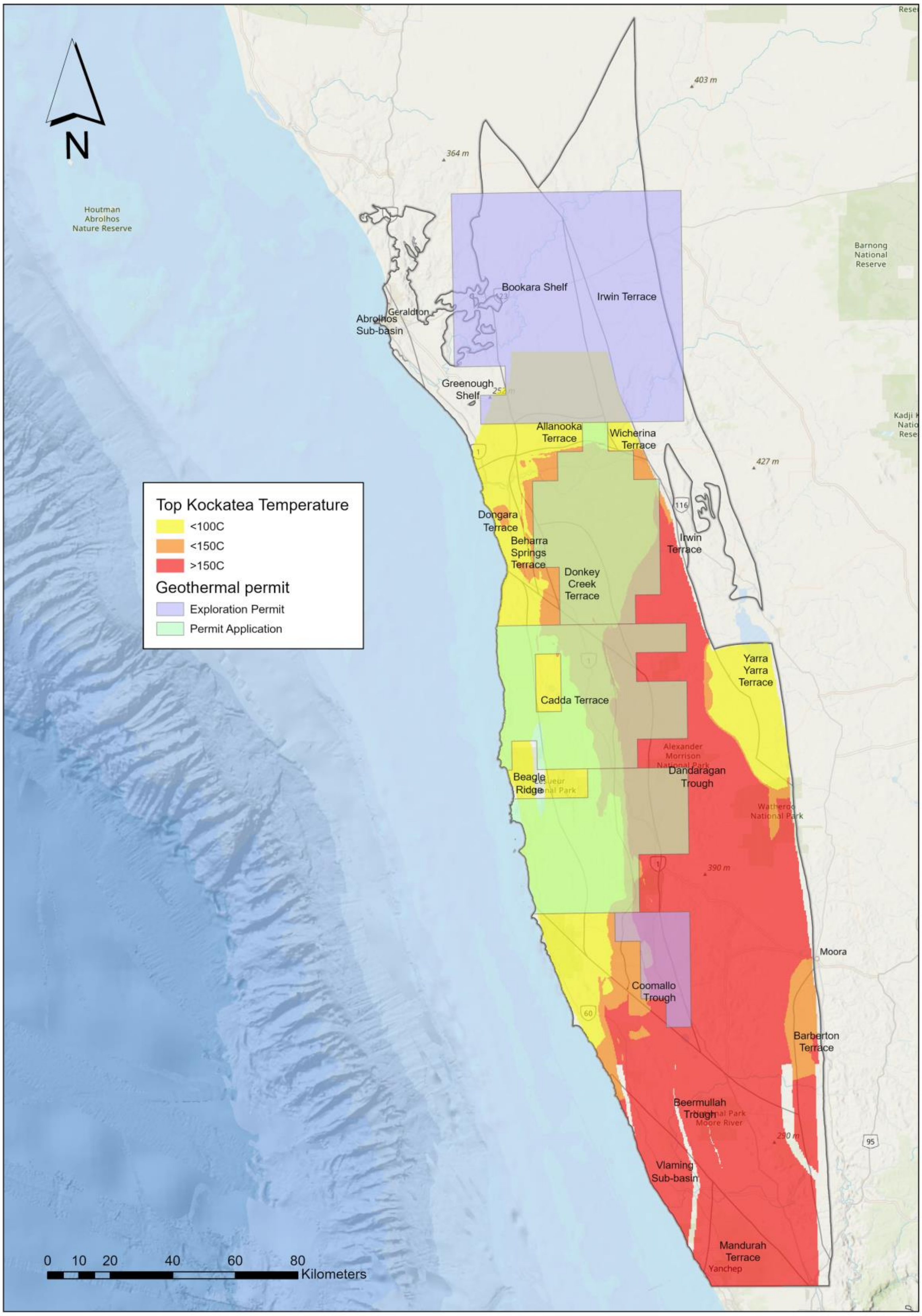



**Figure 29. Temperature at the top of the Kingia Sandstone and location of geothermal titles and applications.**

### 3.2.3. Western Australian geothermal development

Western Australia has experienced considerable growth in direct-use geothermal projects, notably for heating public swimming pools and leisure centres. Several leisure centres utilise geothermal energy, primarily sourced from the Yarragadee Formation in the Perth metropolitan area (Pujol *et al.*, 2015).

Currently there is no active geothermal energy production in the northern Perth Basin. However, several exploration licences have been issued in recent years (Western Australia Government, 2023). For instance, in late 2021, Strike Energy Ltd applied for the first new geothermal exploration license in 10 years and received a significant grant for its northern Perth Basin project. Following the acquisition of Mid West Geothermal Power Pty Ltd in 2021, Strike Energy Ltd announced a geothermal resource of 203 petajoules (PJ) within the Permian Kingia Sandstone at depths of approximately 4000 m and temperatures around 170 °C for its Mid West Geothermal Power Project (www.mwgp.com.au/) under the GSPA 2 AO permit.

VRX Silica Ltd, a pure-play silica sand company listed on the ASX, has received Geothermal Exploration Permit (GEP) 44, covering 8 blocks in Dandaragan (www.australiangeothermal.org.au/post/vrx-silica-granted-geothermal-exploration-permit-in-north-perth-basin-wa). This permit aims to explore geothermal technology for producing renewable energy for the Mid West region, specifically to support VRX's Arrowsmith Silica Sand Projects and the production of green hydrogen for glass manufacturing. VRX Silica has partnered with Hydro X (now Steam Resources) through a farm-in and joint venture agreement to develop GEP 44.

GEP 45 is held by Energy Resources Ltd, a wholly owned subsidiary of Mineral Resources. The permit is for a 6-year period, commencing in July 2023. However, detailed information about the geothermal project under GEP 45 has not been publicly disclosed.

## 3.3. Carbon geological storage resources

### 3.3.1. Background: carbon capture and storage

Carbon capture and storage (CCS) has been identified as one option within a portfolio of technologies to mitigate greenhouse gas emissions into the atmosphere, thereby limiting climate change. Carbon geological storage is the process of storing $CO_2$ extracted from a pre- or post-combustion process in deep geologic reservoirs.

At temperatures and pressures above 31.1 °C and 7.39 MPa, respectively, $CO_2$ is a supercritical fluid with the density of a liquid and viscosity of a gas. These temperature and pressure conditions generally correspond to a depth of approximately 800 m, depending on the local geothermal and pressure gradients. Therefore, $CO_2$ geological storage preferably occurs at depths of 800 m or more below the ground surface, where the $CO_2$ has a relatively high density (~ 200–700 kg/m$^3$), which reduces required subsurface storage volumes and buoyancy-driven migration potential.

Carbon geological storage requires a series of operations (Figure 30) that includes the injection of $CO_2$ through a well. The liquid or supercritical $CO_2$ is delivered via pipeline to the wellhead, where additional compression and heating may be required to ensure continuous $CO_2$ injection (Figure 30).

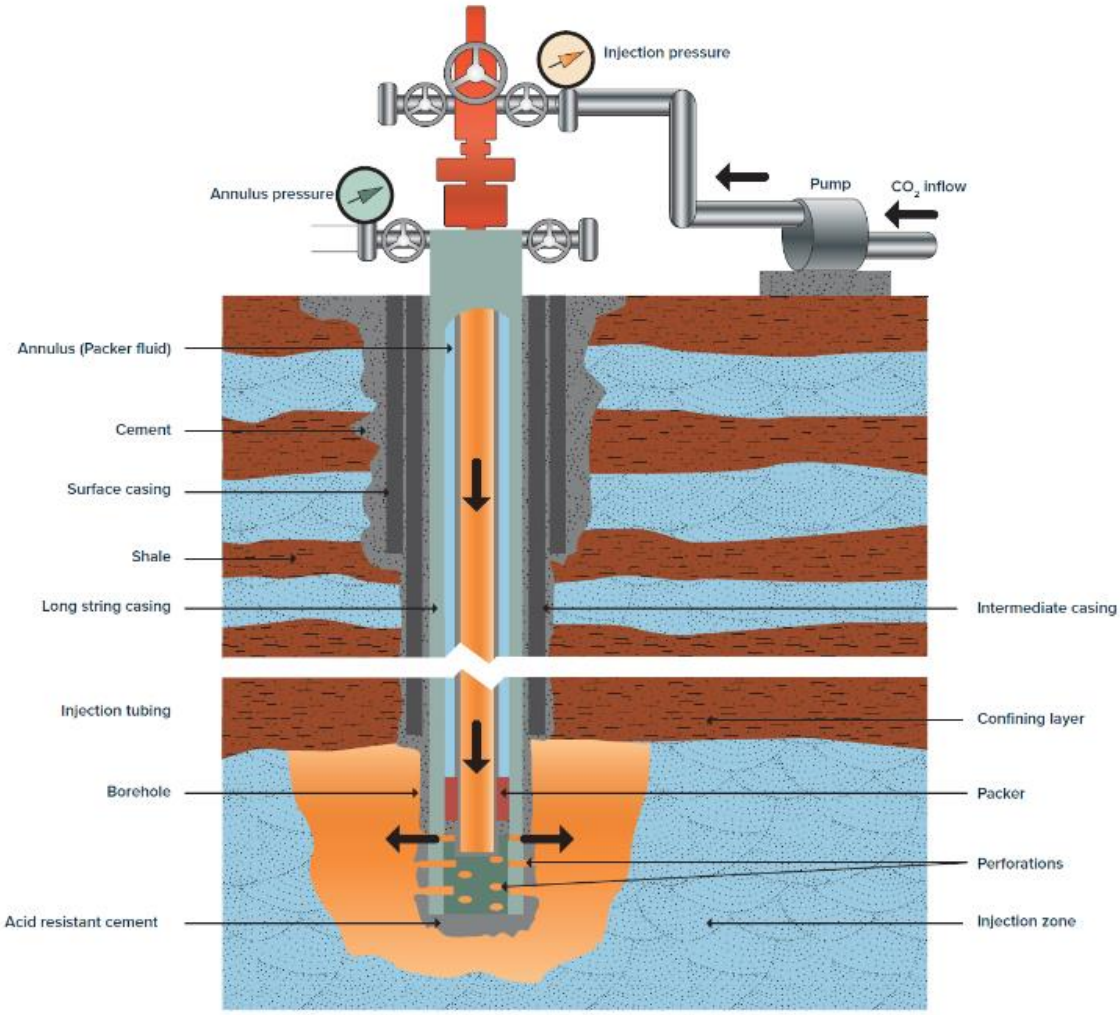



**Figure 30. Schematic showing compression and injection of $CO_2$.**

A $CO_2$ geological storage complex consists of a porous reservoir formation (for example, sandstone or carbonate) and a low-permeability sealing formation (for example, shale or evaporite). It must have the following requirements to prevent leakage to shallower formations or the atmosphere:

1. The reservoir formation needs to have sufficient storage capacity for the anticipated volume of $CO_2$.
2. The reservoir formation needs to have adequate injectivity (as defined by permeability and thickness of the reservoir rock) for accepting $CO_2$ at the desired injection rate. The most important constraint is that the bottomhole injection pressure should remain below the formation fracture pressure.
3. The sealing formation and geological structure of the reservoir complex need to ensure that the injected $CO_2$ is contained within a defined volume and that there are no material impacts on other resources or the environment.

Containment of the $CO_2$ can occur in various ways and over various time scales, with storage security generally increasing over time (Intergovernmental Panel on Climate Change (IPCC), 2005). Structural trapping is the process of trapping free-phase $CO_2$ by buoyancy in a closed structure below an impervious seal, similar to naturally occurring oil and gas fields. As the supercritical $CO_2$ moves through the reservoir rock, small droplets of the $CO_2$ will remain trapped in the centre of each pore and become immobilised by imbibition of formation water; a process termed residual trapping.

When $CO_2$ is injected into a deep aquifer, it will gradually dissolve into the formation water, resulting in $CO_2$-enriched water. This solution is slightly denser than $CO_2$-free water, forcing the $CO_2$-saturated water to migrate downwards due to its negative buoyancy. This process, referred to as solubility trapping, occurs when the $CO_2$ is contained within a structural trap or when it is migrating along the aquifer as it rises from the injection point. $CO_2$ dissolved in water can also react with the rock framework in the form of mineral dissolution or precipitation. Some of these geochemical processes (for example, dissolution and precipitation of calcite) can occur early in the injection process and impact on injectivity. However, trapping large volumes of carbon permanently via mineral trapping of $CO_2$, will take hundreds to thousands of years, depending on the mineralogy of the reservoir rock.

### 3.3.2. $CO_2$ geological storage in the northern Perth Basin

The northern Perth Basin was assessed for its potential for carbon geological storage in saline aquifers by the Carbon Storage Taskforce (2009), the CCS Atlas by 3D-GEO (2013) and Varma *et al.* (2013). An update of the 2013 CCS Atlas is currently being conducted by the Geological Survey of Western Australia (GSWA) and preliminary results were presented by Ellis *et al*. (2024) (Figure 31).

In the onshore northern Perth Basin, potential reservoirs are sandstones of the Beekeeper, Dongara/Wagina, Kingia/High Cliff and Lesueur formations and total P90, P50 and P10 prospective storage capacities were estimated to be 1.4 Gt, 2.9 Gt and 5.3 Gt, respectively (Carbon Storage Taskforce, 2009).

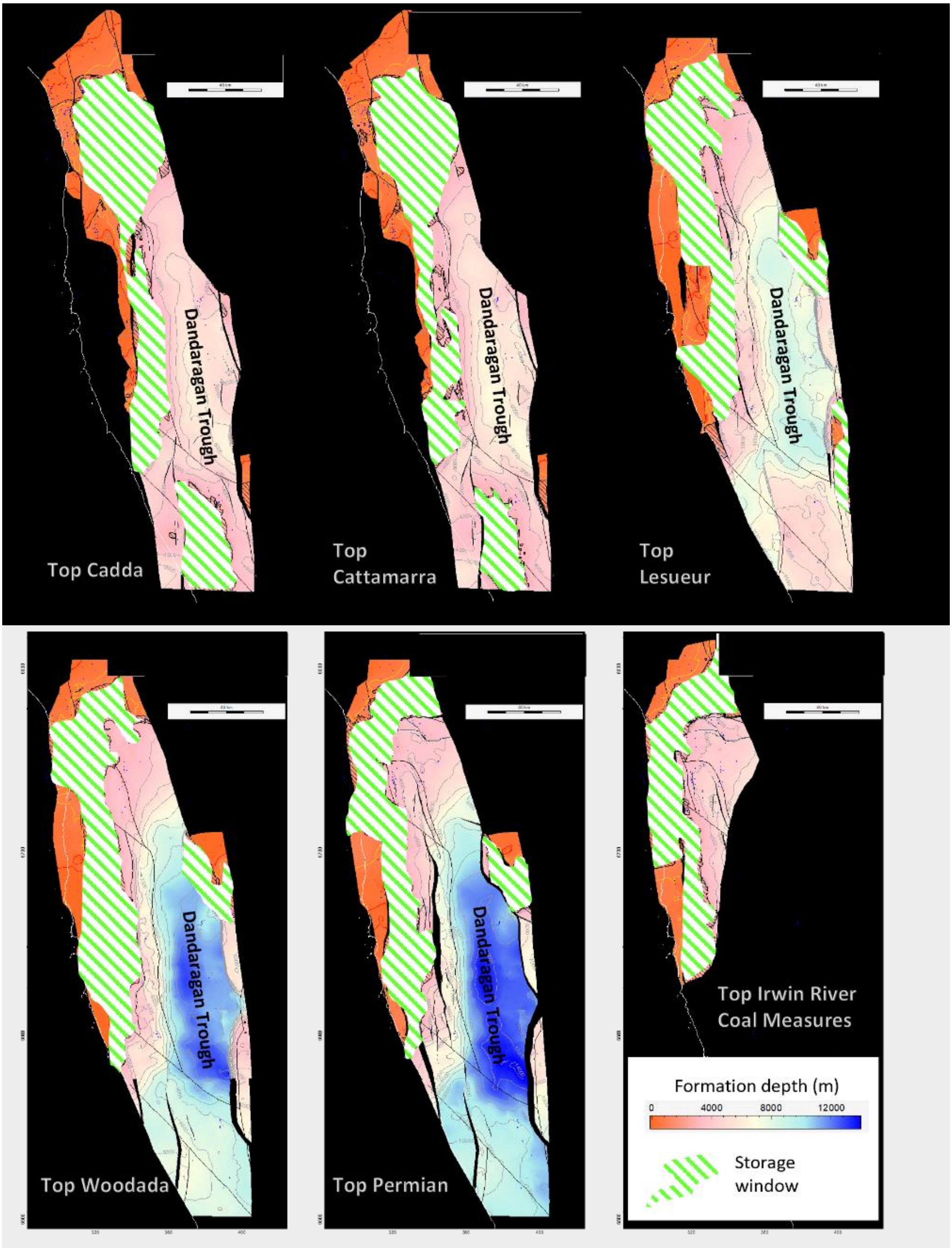



**Figure 31. Preliminary delineation of optimum storage windows (1000–3000 m depth; green hashed areas) in various northern Perth Basin formations (From Ellis *et al.,* 2024).**

Five possible storage leads were identified by 3D-GEO (2013) in the northern Perth Basin (Figure 32), which partly overlap with sites assessed in more detail by Varma *et al.* (2013).

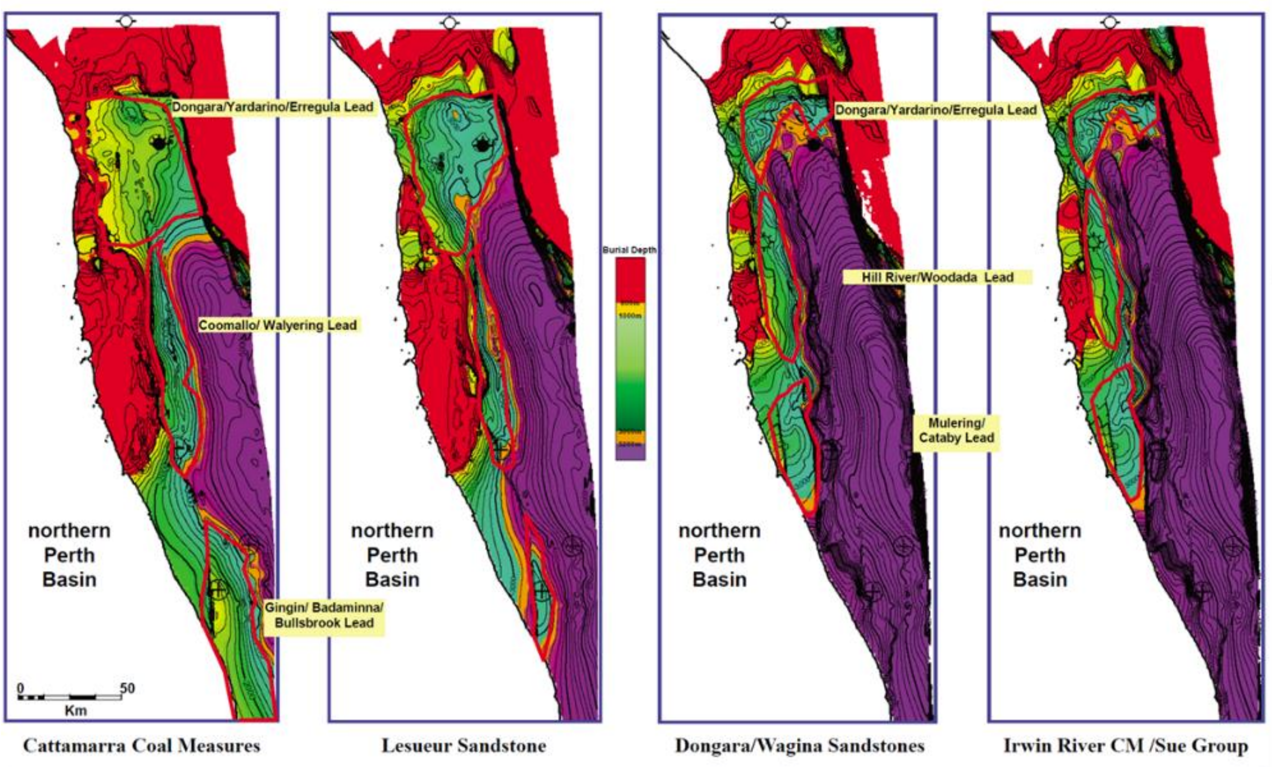



**Figure 32. Burial depth of potential storage formations and location of prospective areas (red outline) for $CO_2$ geological storage identified by 3D-GEO (2013).**

The Dongara/Yardarino area in the northern part of the basin has the highest overall prospective $CO_2$ storage resources (approximately 2 Gt in multiple reservoirs). A more detailed prospect analysis of several smaller areas (Figure 33A) results in a $CO_2$ storage resource of approximately 50–160 Mt (Varma *et al*., 2013). The area also contains hydrocarbon fields with prospective storage resources of up to 52 Mt in the Dongara field (Figure 33B and Figure 33C). Geological data and operational experience from these fields reduce the overall uncertainty for containment and reservoir properties, but may delay geological storage implementation until reservoir depletion. A hybrid model of combining storage in a depleted gas field with storage in underlying aquifers is shown in Figure 34. While it would be difficult to exceed the full aquifer volume for storage, extending the storage reservoir, beyond the part of the structure previously filled with natural gas, may provide an option to increase storage capacity of a depleted gas field.

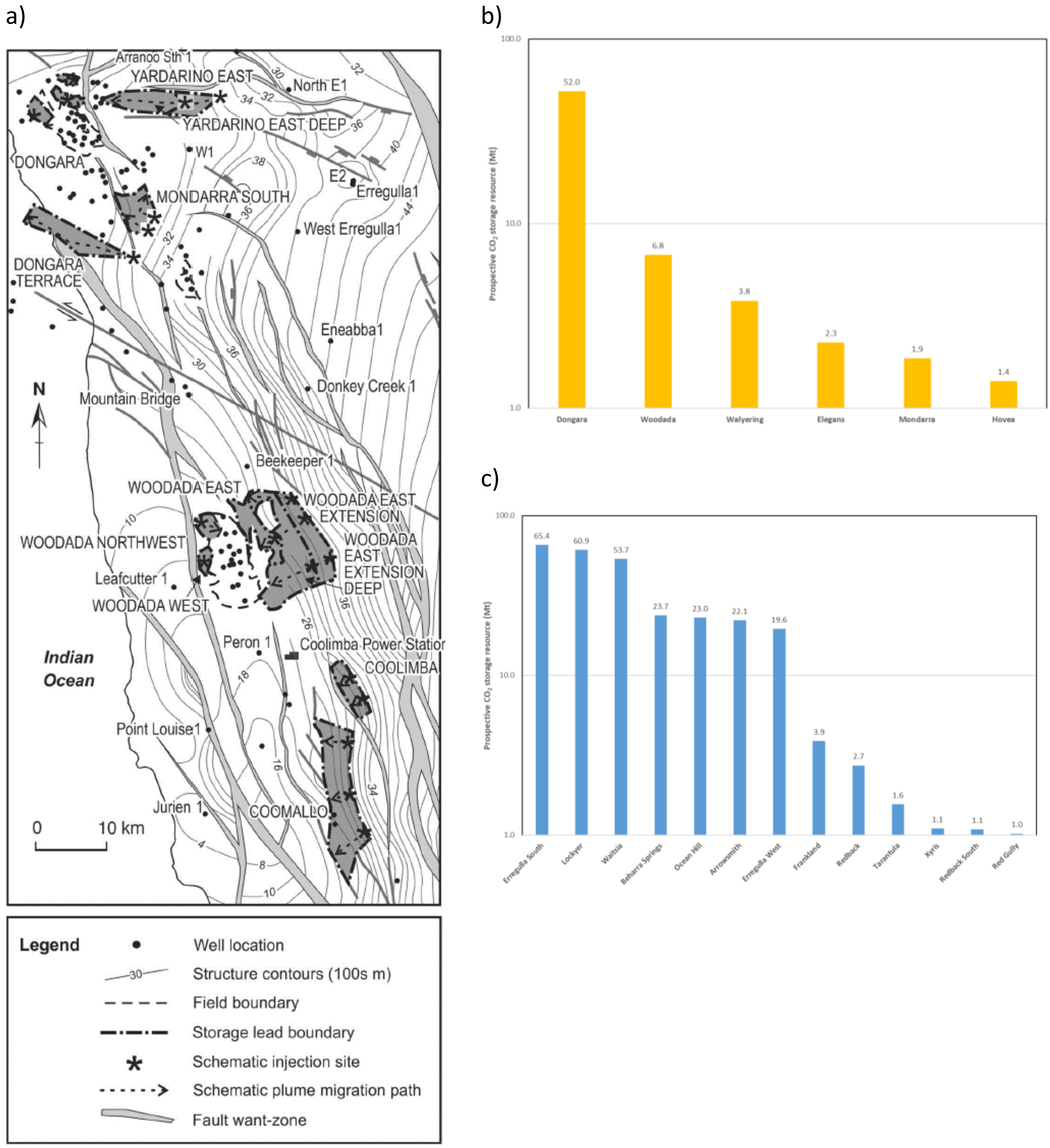



**Figure 33. a) Potential $CO_2$ storage prospects in the northern Perth Basin (modified from Varma *et al.,* 2013). Prospective $CO_2$ storage resources (> 1 Mt) in the northern Perth Basin in b) depleted gas fields, and c) producing or un-produced fields.**

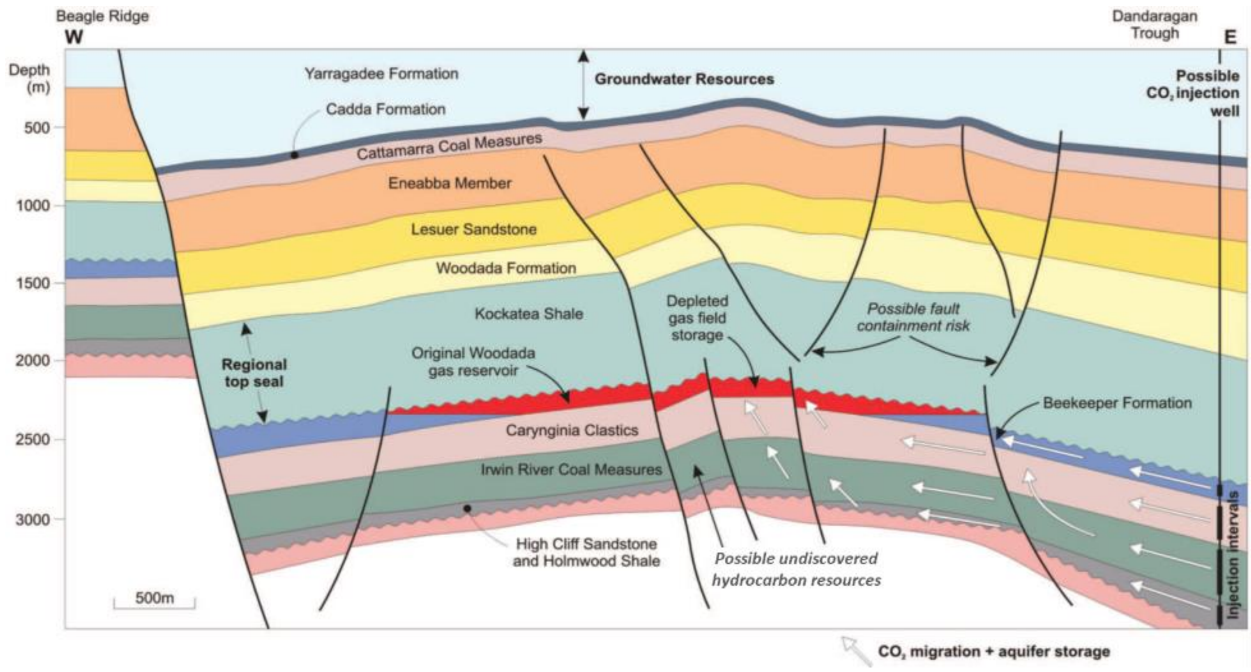



**Figure 34. Hybrid $CO_2$ storage model in depleted Woodada gas field and underlying aquifers (Varma *et al.,* 2013).**

### 3.3.3. Industrial projects with carbon capture and storage

Ammonia can be used as a low-emissions fuel for power generation, transportation and other applications, or to produce fertilisers and other chemicals. If $CO_2$ captured from the production of ammonia through steam methane reforming (SMR) of natural gas was injected and stored in a geological reservoir, this would be considered 'low-emissions ammonia,' also called 'blue ammonia'.

Building on the existing natural gas operations, blue ammonia projects are being considered by Mitsui E&P Australia (MEPAU) and Wesfarmers Chemicals, Energy & Fertilisers Limited (WesCEF), (www.mitsui.com/jp/en/topics/2021/1242033_12171.html). MEPAU has a 50% working interest, and is operating the Waitsia gas field near Dongara. MEPAU also holds up to 100% working interest in nearby depleted gas fields. As the first phase of its Cygnus CCS Hub, MEPAU conducted a small-scale $CO_2$ injection pilot test (~46 tonnes) in its depleted Dongara gas field in February 2024 (www.mepau.com.au/successful-co2-injection-test/).

WesCEF has an existing fertiliser plant in the Kwinana industrial area, south of Perth, and plans are being considered to capture and transport $CO_2$ emissions from the plant to a storage site in the northern Perth Basin, either by truck or by pipeline.

Similarly, the Pilot Energy Mid West Clean Energy Project (MWCEP) proposes hydrogen production using partial oxidation reforming with > 1 Mt/yr of integrated CCS capacity, and renewables-based hydrogen to produce up to 220,000 t/yr of blue ammonia (www.pilotenergy.com.au/mid-west-clean-energy-project). The proposed storage location is the offshore Cliff Head oil field.

## 3.4. Underground gas storage resources

### 3.4.1. Background: underground gas storage

There are 2 important criteria needed for an underground natural gas or hydrogen storage reservoir:

1. sufficient capacity to hold gas for future use
2. sufficient reservoir injectivity/productivity that allows the planned rate at which the gas can be injected and withdrawn (EIA, 2019).

There are 3 engineering and design objectives for a UGS site (Katz and Tek, 1999):

1. maximum gas storage capacity
2. minimal gas losses
3. sustainability of gas delivery rate.

The key UGS components are illustrated in Figure 35.

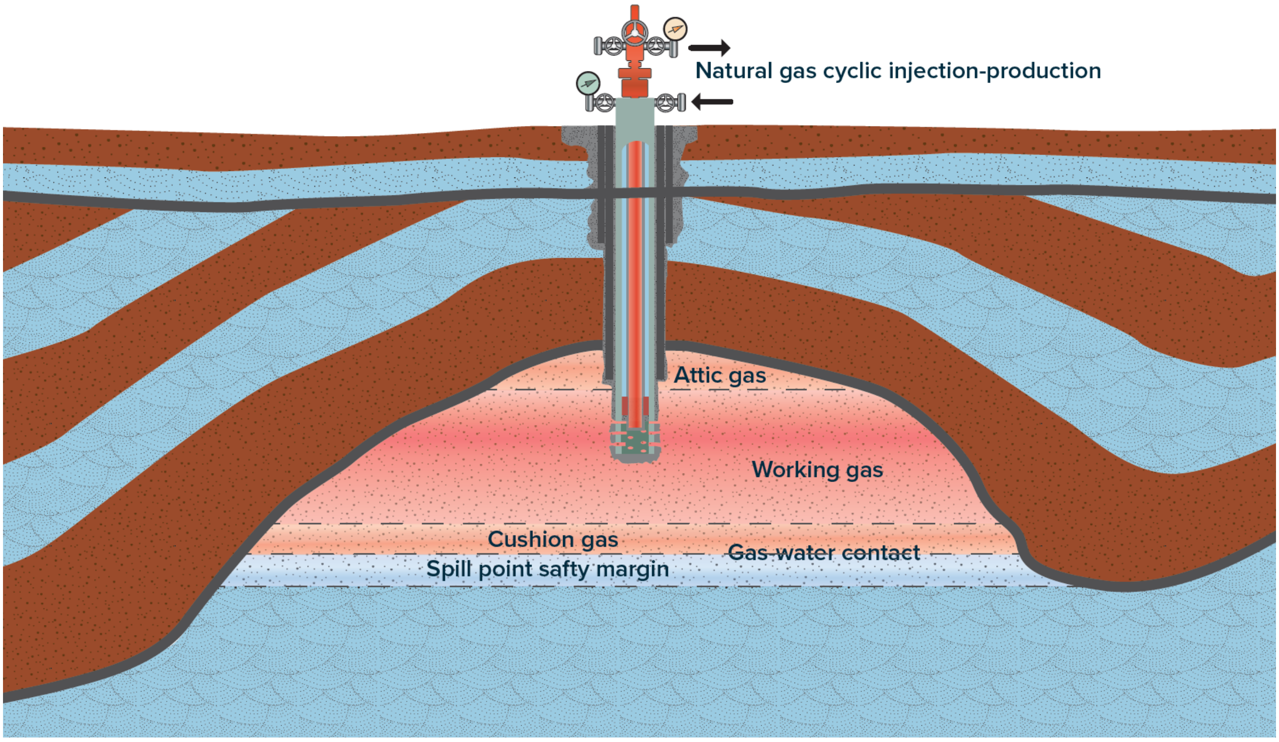



**Figure** 35**. Schematic cross-section showing key principles for UGS.**

### 3.4.2. Natural gas storage in the northern Perth Basin

The only natural gas storage operation in the northern Perth Basin is the Mondarra gas storage facility near Dongara, operated by the APA Group. The operation uses a depleted gas field and consists of 3 injection/production wells in the Dongara Sandstone at a depth of approximately 2700 m (Figure **36**). The storage reservoir has a total storage capacity of 15 PJ, the capability to inject gas at 70 TJ/day, and withdraw gas at 150 TJ/day (APA, 2013). This is equivalent to an approximate storage volume of 24 billion cubic feet (BCF), or 0.7 km$^3$.

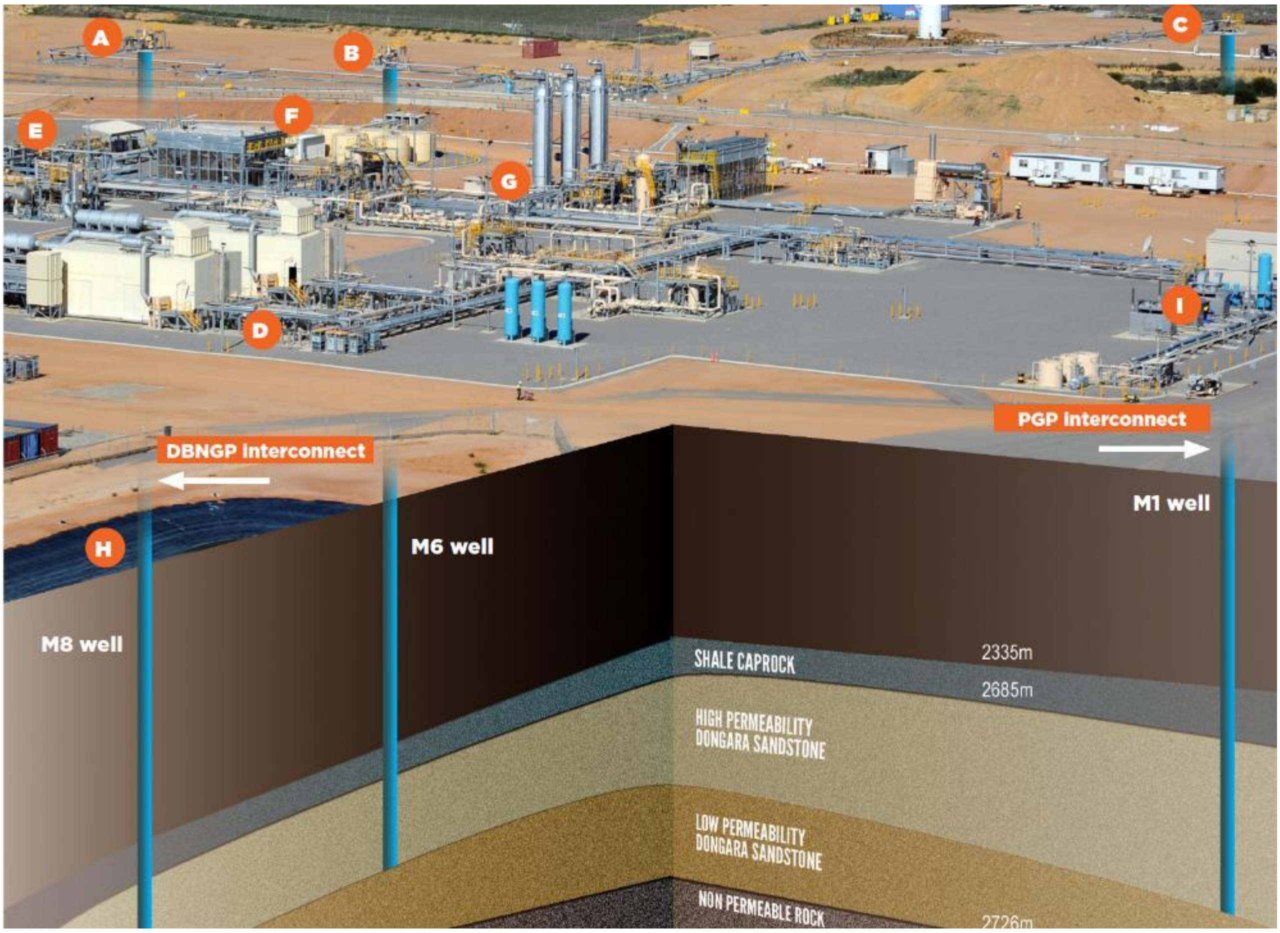



**Figure 36. Schematic diagram of the Mondarra gas storage facility showing the location of: A), B), and C) injection/production wells, D) aerial reciprocating compressors, E) gas processing facility, F) cooler and separator, G) conditioning package unit, H) evaporation pond, and I) gas engine alternators. The facility is connected to the Dampier to Bunbury Natural Gas Pipeline (DBNGP) and the Parmelia Gas Pipeline (PGP). APA (2013).**

### 3.4.3. Underground hydrogen storage in the northern Perth Basin

Currently, there is no hydrogen produced in the northern Perth Basin. However, future plans by Mitsui E&P Australia and Pilot Energy include the production of ammonia from natural gas, which involves hydrogen intermediates or by-products that may require underground storage. Also, future hydrogen production from renewable energy projects may necessitate underground storage. Therefore, the *Western Australian Renewable Hydrogen Roadmap (November 2020)* considers utilising depleted oil and gas fields for hydrogen storage. RISC (2021) performed a screening study for the Western Australian Government, evaluating the potential of depleted oil and gas reservoirs for underground hydrogen storage. Twenty-one of the assessed fields were located in the northern Perth Basin, 6 of which have been deemed as having strong storage potential, and 6 having moderate storage potential (Table 3). Potential competition with other users includes natural gas storage (i.e. Mondarra), expansion of petroleum operations (i.e. Beharra Springs) and $CO_2$ geological storage (i.e. Dongara).

**Table 3. Underground hydrogen potential in oil and gas fields in the northern Perth Basin (RISC, 2021).**

| Field | Storage volume (BCF) | $H_2$ storage potential | Reasoning/risks |
|---|---|---|---|
| **Xyris (gas)** | 9.3 | Strong | Good storage capacity, high-quality reservoir. |
| **Yardarino (gas)** | 5.1 | Strong | Good storage capacity, high-quality reservoir – less production than Xyris so lower storage potential. |
| **Beharra Springs (gas)** | 89 | Strong | Good storage capacity, high-quality reservoir. Beharra Springs Deep under development. |
| **Redback (gas)** | 22 | Strong | Good storage capacity, high-quality reservoir. Beharra Springs Deep under development. |
| **Tarantula (gas)** | 19 | Strong | Good storage capacity, permeability low at 10–20 mD. |
| **Mondarra (gas storage)** | 24 | Strong | Good storage capacity. Currently used as natural gas storage facility (not currently available). High productivity. |
| **Dongara (gas)** | 458 | Moderate | Very high storage capacity, potentially too large for H2 requirements. Good reservoir properties. Many (47) wells. |
| **Red Gully (gas)** | 4.0 | Moderate | Good storage capacity, high-quality reservoir, wells watered out. |
| **Apium (gas)** | 1.2 | Moderate | Sufficient gas production – permeability is very low (< 5 mD), reducing potential injection and withdrawal rates. |
| **Gingin (gas)** | 1.7 | Moderate | Sufficient gas production – varying properties across field, poor deliverability in production wells. |
| **Hovea (oil)** | 3.4 | Moderate | Good storage capacity, high permeability – risk of potential $H_2$ dissolution and contamination in/from oil. |
| **Mt Horner (oil)** | 1.0 | Moderate | Limited storage capacity, high water saturation – risk of potential $H_2$ dissolution and contamination in/from oil. |

## 3.5. Groundwater resources

The northern Perth Basin groundwater aquifers supply about 95% of water used for town water supply, agriculture, mining and petroleum industries (Department of Water, 2017). These aquifers also support many groundwater-dependent wetlands, watercourses, vegetation associations and cave and aquifer ecosystems in the Mid West region.

### 3.5.1. Background: groundwater

Groundwater is an integral part of the hydrologic cycle. The quantity and quality of groundwater resources require careful management to ensure sustainable use for domestic, industrial and environmental needs. Depending on the jurisdiction, the salinity of groundwater constrains its possible usage. For example, potable water (< 1000 mg/l), irrigation or domestic washing purposes (< 2,000 mg/l), and stock watering (< 10,000 mg/l). Groundwater with a salinity of > 10,000 mg/l is generally used only for specific industrial purposes. Thus, sedimentary basins may have multiple groundwater requirements from municipalities, households, agriculture, mining, geothermal applications, $CO_2$ geological storage and petroleum production, which collectively place a cumulative stress on groundwater resources. Therefore, knowledge of a basin's usable groundwater distribution, jurisdictions and existing policies is required for planning and management of potential resource interactions.

Basin-scale characterisation of the groundwater resource, along with knowledge of the regional setting (including climate, geomorphology, drainage, and land-use), is needed as a starting point for developing a basin resource management strategy. The main information required for suitable groundwater characterisation are:

- The geological distribution of aquifers and aquitards (rocks that greatly restrict or limit groundwater flow and that can be sealing rocks for storage) and their hydraulic properties, such as porosity and permeability.
- Baseline groundwater levels and flows within aquifers under natural conditions and, where possible, records of historical changes arising from climate variability, pumping and land-use.
- Baseline or current groundwater quality parameters.
- Groundwater-dependent ecosystem requirements.
- Locations and rates of basin recharge and discharge.
- Locations of subsurface features affecting flow paths or regions of cross-formational flow.
- Volume of groundwater in storage.

### 3.5.2. Groundwater resources in the northern Perth Basin

The primary aquifers used as groundwater resources in the northern Perth Basin are the Superficial, Leederville, Leederville-Parmelia and Yarragadee aquifers. Secondary sources are provided by aquifers in the Cattamarra Coal Measures and Eneabba-Lesueur formations (Table 4).

**Table 4. Hydrostratigraphy and aquifer use in the northern Perth Basin (simplified from Department of Water, 2017).**

| Period | Hydrostratigraphy | Aquifer characteristics | Usage |
|---|---|---|---|
| Quaternary and Neogene | Superficial aquifer | Minor to major aquifer beneath Swan Coastal Plain; fresh to saline | Major groundwater resource |
| Cretaceous | Mirabooka aquifer | Minor to moderate aquifer beneath southern Dandaragan Plateau; fresh to brackish | |
| | Kardinya aquitard | | |
| | Leederville aquifer | Major aquifer below the coastal plain south of Cataby (combined with Parmelia Group beneath Dandaragan Plateau to form the Leederville-Parmelia aquifer); fresh | |
| | South Perth aquitard | | |
| | Leederville-Parmelia aquifer | Hydraulically connected with Yarragadee aquifer | Major groundwater resource;<br><br>Minor oil and gas accumulations;<br><br>Secondary potential for $CO_2$ storage |
| Jurassic | Otowiri aquitard | Extensive aquitard below Dandaragan Plateau (includes shaley part of the Carnac Formation) | |
| | Yarragadee aquifer | Major regional aquifer; Mostly fresh | |
| | Cattamarra aquifer | Interbedded aquifer-aquitard on Cadda Terrace; mostly brackish | |
| | Eneabba-Lesueur aquifer | Major aquifer on Beagle Ridge-Cadda Terrace; fresh to brackish | |
| Triassic | | | |
| | Kockatea aquitard | | |
| Permian | Wagina aquifer | Local aquifer in north; saline | Gas production; gas storage |
| | Caryngina aquitard | | |
| | Irwin-High Cliff aquifer | Poor to moderate aquifer; saline | Gas production |
| | Holmwood aquitard | | |
| | Nangetty aquifer | Poor to moderate aquifer; saline | Gas production |
| Silurian-Ordovician | Tumblagooda aquifer | Regional aquifer in northern margin of Perth Basin. Mostly fractured rock aquifer; brackish to saline – locally fresh | |
| Proterozoic | | Poor, fractured-rock aquifer; fresh to brackish | |

Due to the structural history of the basin, aquifers can be close to the ground surface, either as outcrop or subcropping below Cenozoic superficial sediments (Figure 37). In most regions of the northern Perth Basin, the base of the Yarragadee aquifer is the lower limit for meteoric flow systems (Commander, 1981). Where the Yarragadee aquifer is absent, the base of the meteoric flow systems is usually the base of the shallowest aquifer present. Meteroic (originating from rainfall) influx of fresh water has flushed the remnants of high salinity seawater from most of these shallow aquifers above the Kockatea Shale (Department of Water, 2017). Regional flow in the northern Perth Basin is generally from east to west, with recharge in areas of topographic high along the basin margin and discharge along the shoreline and partly offshore (Figure 38). Salinity of formation water in the upper 1000 m is generally below 3000 mg/l, except for brackish formation water, which exhibits salinity of up to 10,000 mg/l due to the incursion of marine water close to the shoreline (for example, the Dongara line Well DL1 in Figure 38).

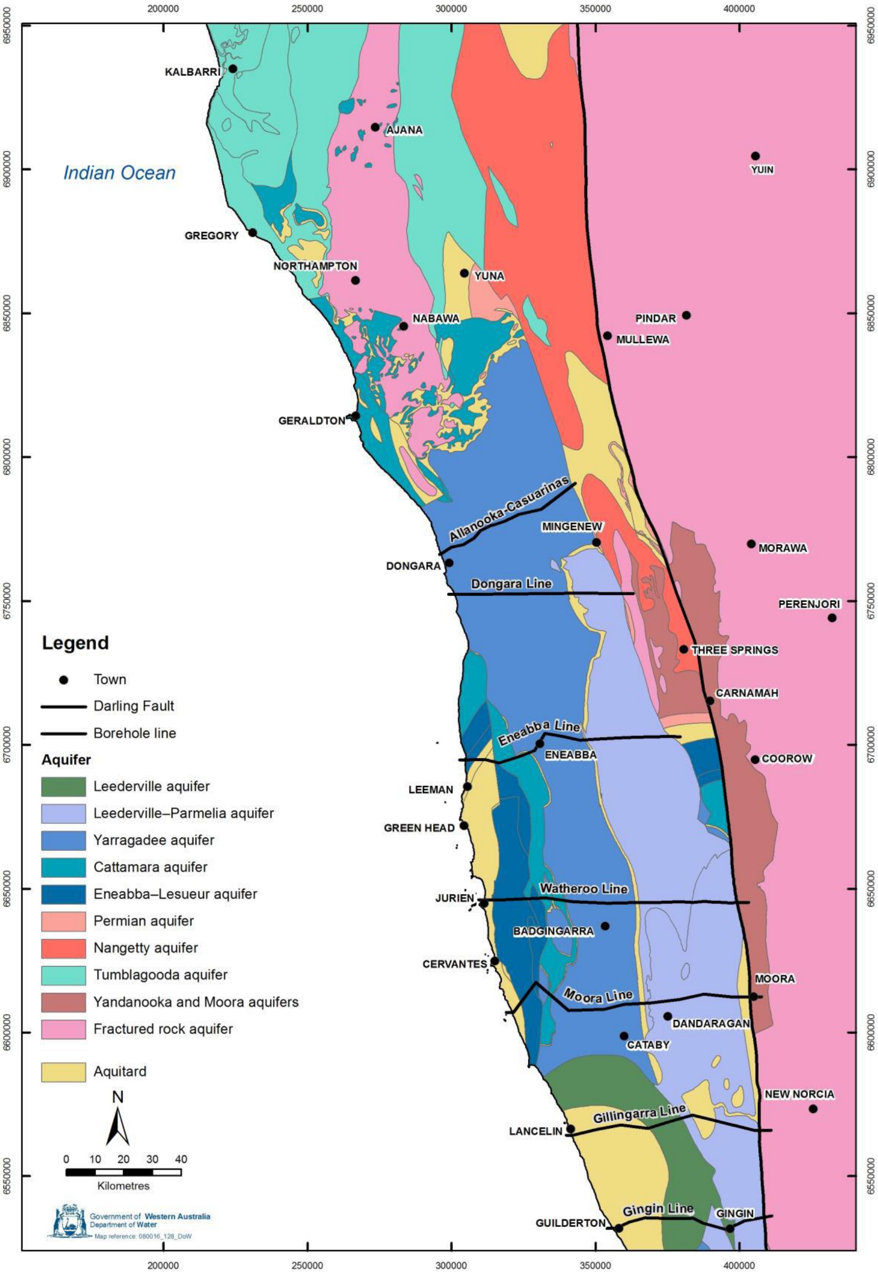
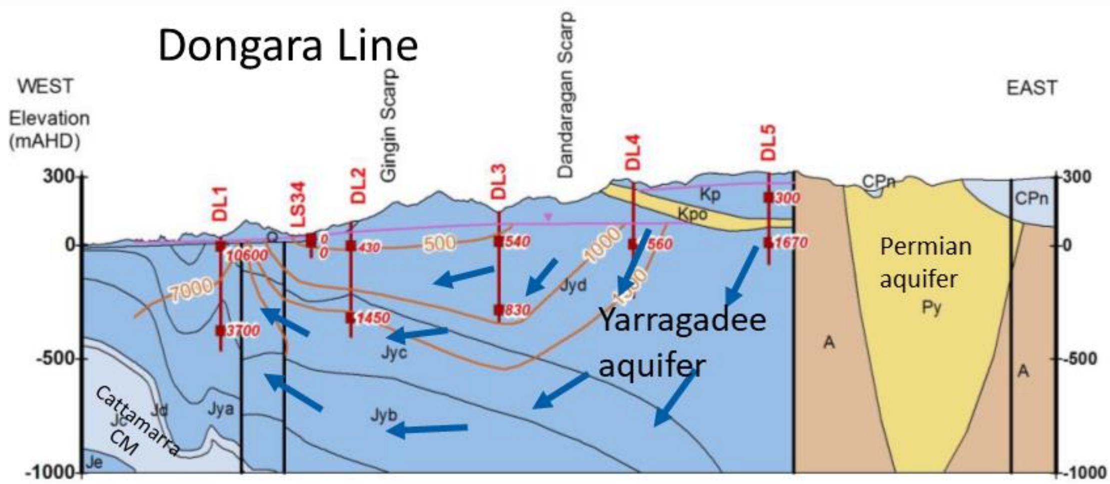
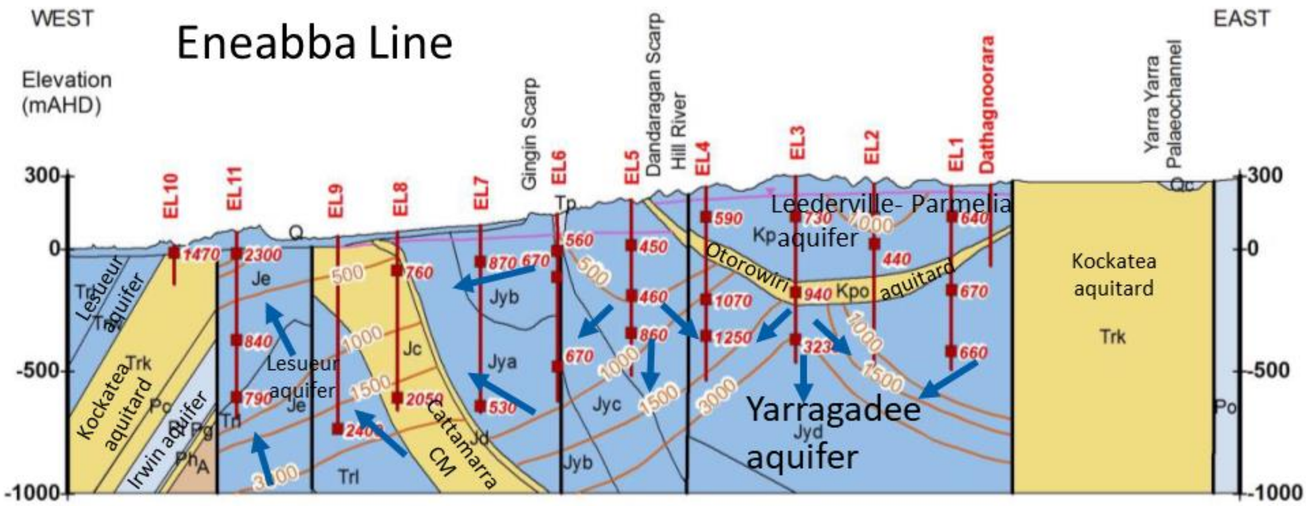



**Figure 37. Shallow aquifers and aquitards below superficial formations or surficial deposits (Department of Water, 2017). Also shown are the Dongara, Eneabba and Gillingarra cross-section lines in Figure 38.**

a)




b)




c)

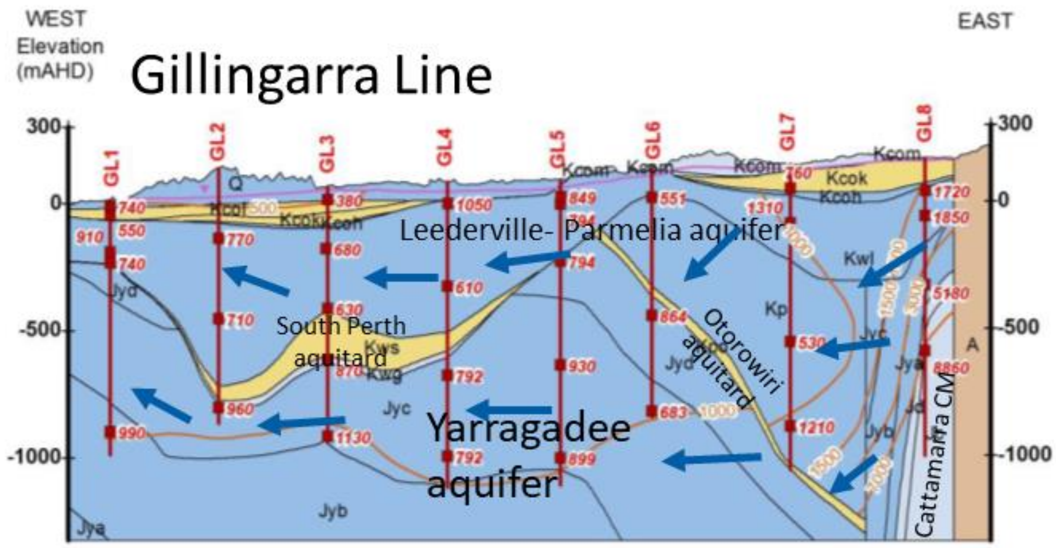



**Figure 38. Hydrogeological cross-sections showing salinity (mg/l) distribution and inferred water flow directions (blue arrows): a) Dongara line, b) Eneabba line, c) Gillingarra line. See Figure 37 for location of cross-section lines. Modified from Department of Water (2017).**

A natural interface between low-salinity groundwater and denser seawater forms a wedge within any unconfined aquifer along the coastline (Figure 39). The location of the interface is dynamic, moving inland if fresh groundwater flow is reduced by abstraction or low rainfall recharge (seawater intrusion). As a consequence, bores located in fresh groundwater above the seawater wedge or near the inland toe of the wedge may become saline, which poses a risk to coastal communities and groundwater-dependent ecosystems (GDEs) like wetlands (Department of Water, 2017).

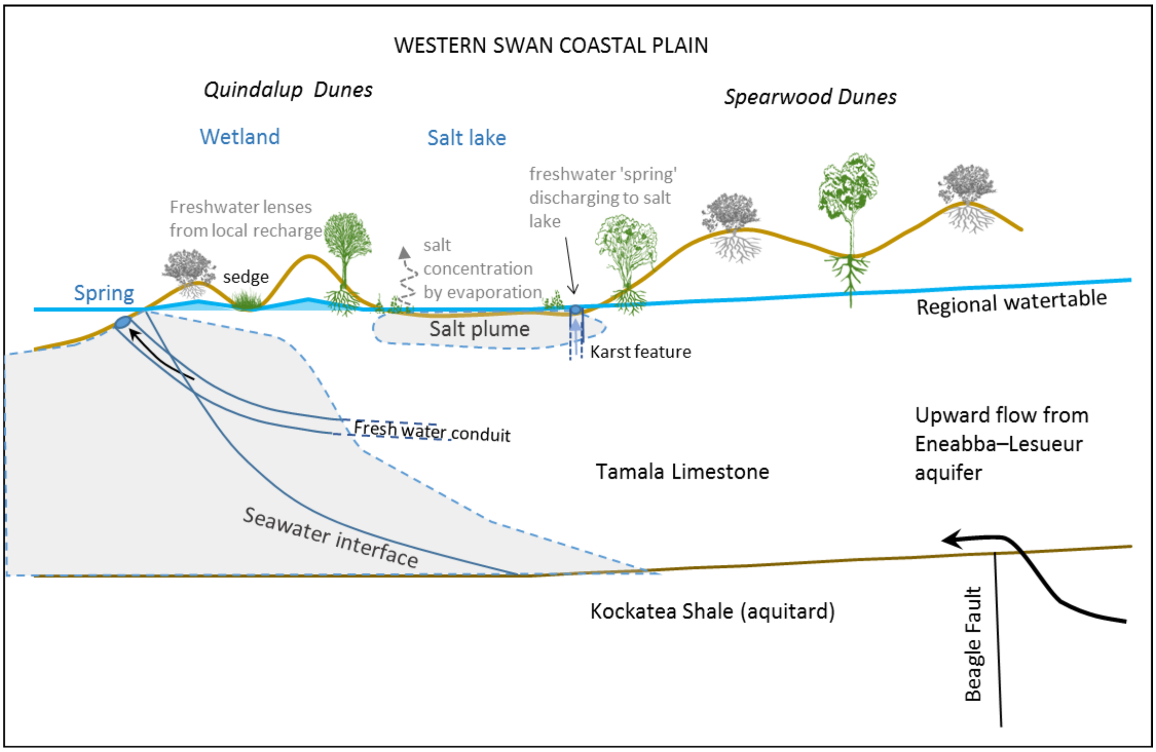



**Figure 39. Schematic diagram showing the seawater-groundwater interface in aquifers along the coastline (Department of Water, 2017).**

### 3.5.3. Groundwater management

The northern Perth Basin aquifers supply about 95% of all water used for town water supply, agriculture, mining and petroleum industries (Department of Water, 2017). Licenses to withdraw groundwater by various stakeholders are managed within 4 groundwater management areas: Gnangara, Gingin, Jurien and Arrowsmith (Figure 40).

DWER have developed Water allocation plans for each region that outline how much water can be taken from groundwater and surface water resources, while safeguarding their sustainability and protecting water-dependent environments. Water allocation plans are used to guide individual water licensing decisions and inform how:

- water resources information will be collected
- water management will be adapted to changing circumstances
- water resources can be best used.

Water management plans are currently being updated for Gingin, Jurien and Arrowsmith. Data quoted in this section is largely from 2015–17 publications (Department of Water, 2015a and 2015b; Department of Water, 2017).

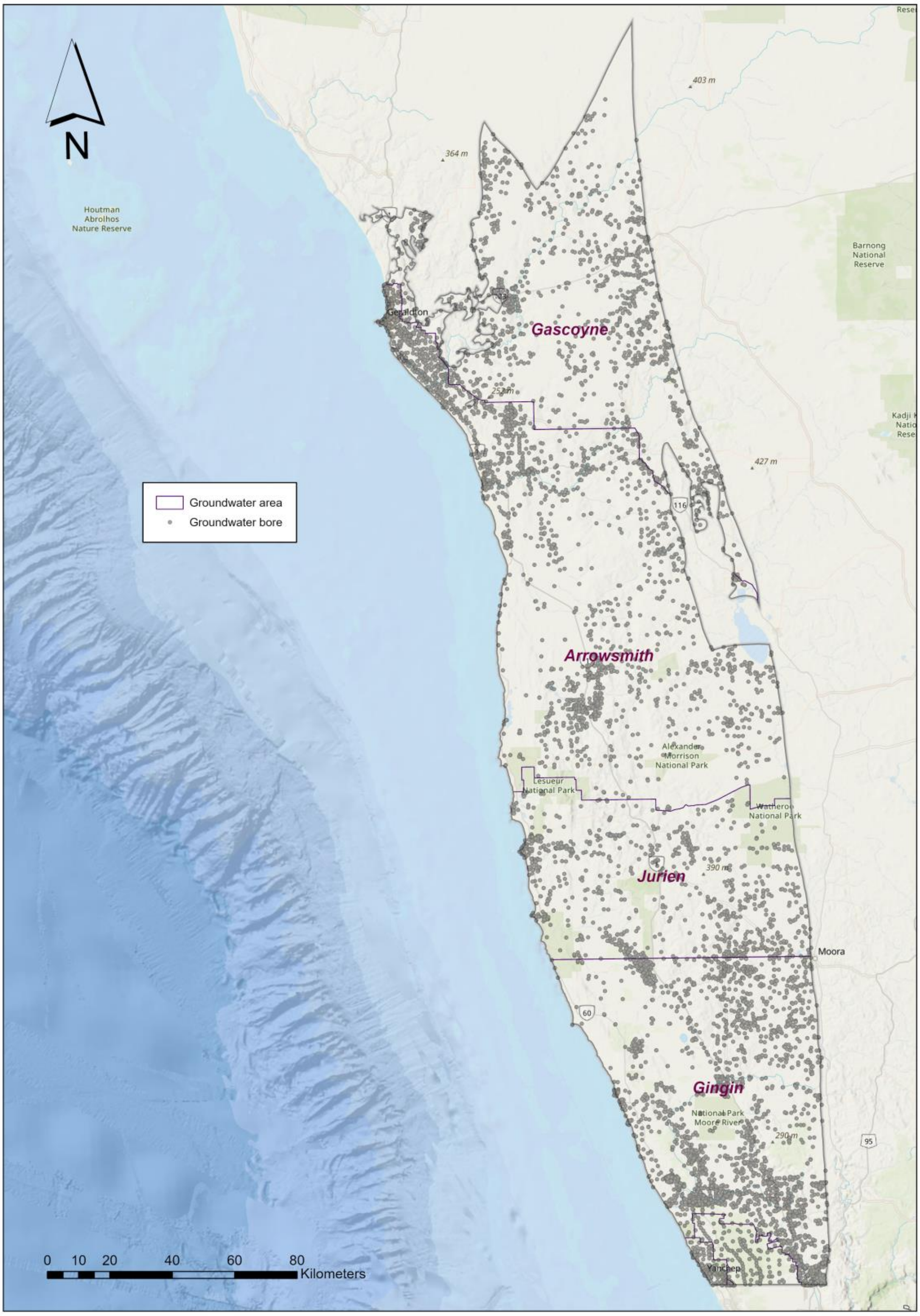



**Figure 40. Groundwater management areas in the northern Perth Basin (Rutherford *et al.,* 2005) and distribution of groundwater production wells.**

The majority of water wells have been drilled to a depth of less than 100 m (Figure 41). Some deeper water wells (up to 2000 m in depth) were drilled mainly for monitoring purposes or industrial use.

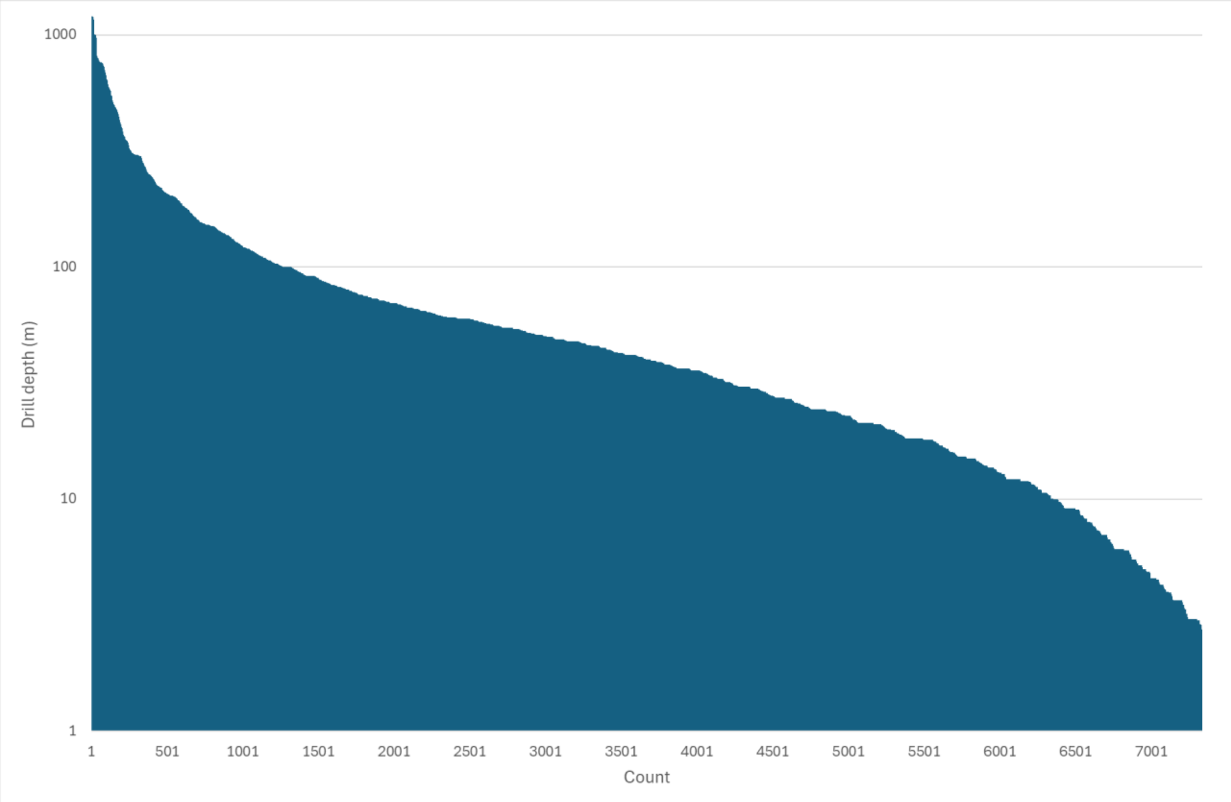



**Figure 41. Drilled depth of water wells in the northern Perth Basin. Depth is shown on a logarithmic scale along the y-axis.**

Currently, most groundwater withdrawal in the Arrowsmith and Jurien groundwater areas is from the Yarragadee aquifer (Figure 40). Long-term outlooks suggest that water supplies in Geraldton and towns such as Jurien Bay and Morawa are secure until at least 2030, assuming that about 200 GL/year of groundwater will be available to meet anticipated future demands (Department of Water, 2015a). The total volume of water remaining in the region for licensing is greater than the projected demand. However, the proposed water supply options for the port and industrial estate at Oakajee include piping water from the Yarragadee aquifer from outside the Mid West groundwater areas, for example, from north of the Irwin River (in the Allanooka and Casuarinas subareas) or from the Carnarvon Basin, and desalinating seawater onsite (Department of Water, 2015a).

The Midlands groundwater and land assessment is investigating groundwater availability, land capability and crop suitability in the area between Gingin and Dongara as part of the state government's Royalties for Regions Water for Food project. The upper bound of projected demand for irrigated agriculture in the entire Mid West region by 2043 is about 30 GL/year (Department of Water, 2015a).

In the Gingin management area, most groundwater abstraction is from unconfined surficial or superficial aquifers. Future growth is expected, particularly to the north of Gingin, in the western part of the Wheatbelt region. However, there is less than 40 GL/year of groundwater available for further allocation (Department of Water, 2017).

There is scope for increased abstraction from current groundwater sources and for the development of new major sources that are located away from areas of greatest groundwater demand. Potential new sources are mainly within the Superficial aquifer north-east of Lancelin, the unconfined Yarragadee aquifer between the Hill and Irwin rivers and in the coastal Cattamarra and Eneabba-Lesueur aquifers (Department of Water, 2017). Desalination of brackish or saline groundwater could be practical if cheap sources of energy are available.

There are 4 main drivers of future water demand in the northern Perth Basin region, according to the Department of Water (2015a and 2017):

- proposed and planned mining projects
- a potential future port facility and industrial estate at Oakajee (24 km north of Geraldton)
- growth of Geraldton and other rural towns
- northward expansion of irrigated agriculture and horticulture, including the Water for Food Midlands area between Moora and Dongara.