# H2RESTORE PROJECT

## FEASIBILITY SUMMARY REPORT

November 2025



**Public Report**

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# ACKNOWLEDGEMENT OF COUNTRY

In the spirit of reconciliation Lochard Energy acknowledges the **Eastern Maar and Gunditjmara People**, the Traditional Owners of the land on which the H2RESTORE project could be located on.

We pay our respects to their Elders past, present and future and extend that respect to all Aboriginal and Torres Strait Islander peoples today.

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# ABBREVIATIONS, TERMS AND ACRONYMS

| Abbreviation or Term | Description |
|---|---|
| AACE | Association for the Advancement of Cost Engineering |
| AEM | Anion Exchange Membrane electrolyser |
| API RP | American Petroleum Institute Recommended Practise |
| ARENA | Australian Renewable Energy Agency |
| AWE | Alkaline Water Electrolysis |
| barg | Bar gauge (pressure unit) |
| BESS | Battery Energy Storage System |
| CAPEX | Capital Expenditure |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation |
| $CH_4$ | Methane |
| Demonstration Pilot, Pilot, | Potential UHS pilot in the Otway Basin to demonstrate the injection and withdrawal of hydrogen in a depleted gas field |
| DN | Diameter Nominal (pipe size) |
| DNA | Deoxyribonucleic acid |
| EOI | Expression of Interest |
| FCAS | Frequency Control Ancillary Services |
| FEED | Front-End Engineering Design |
| FFCRC | Future Fuels Cooperative Research Centre |
| FY24 | Financial Year 2024 |
| GL | Gigalitre (billion litres) |
| GMA | Groundwater Management Area |
| GPG | Gas Powered Generation |
| GWh | Gigawatt hour |
| $H_2$ | Hydrogen |
| H2RESTORE or H2RESTORE Project or the Project | Lochard's potential Otway underground hydrogen storage project |
| $H_2S$ | Hydrogen Sulphide |
| HAZID | Hazard Identification |
| HPG | Hydrogen Powered Generator |
| HP | High Pressure |
| HP PEM | High pressure Proton Exchange Membrane |
| HSS | Hydrogen Storage Site |
| HT | High Temperature |
| IAP2 | International Association for Public Participation |
| IGSF | Iona Gas Storage Facility |
| IRR | Internal Rate of Return |
| ISP | AEMO's Integrated System Plan, as updated from time to time |
| K | Potassium |

| Abbreviation or Term | Description |
|---|---|
| KS | Knowledge Sharing |
| kV | Kilo volt |
| LCOE | Levelised Cost of Energy |
| LCOH | Levelised Cost of Hydrogen |
| LDES | Long Duration Energy Storage |
| Lochard | Lochard Energy |
| MAOP | Maximum Allowable Operating Pressure |
| MCA | Multi-Criteria Assessment |
| Medical CT | Medical computed tomography scan |
| MEM | Mechanical Earth Model |
| MFCT | Mylor, Fenton Creek & Tregony gas fields |
| Micro CT | Micro-CT is a 3 Dimensional imaging technique utilizing X-rays to see inside an object |
| MLF | Marginal Loss Factor |
| MMscf | Million standard cubic feet |
| MOOSE | Multiphysics Object Oriented Simulation Environment. Open source finite element Multiphysics modelling framework |
| MVC | MVC Services Ltd. regulatory consultants providing support to Lochard on this project |
| MW | Mega Watt |
| NEM | National Electricity Market |
| NMR | Nuclear Magnetic Resonance |
| NPV | Net Present Value |
| NOx | Nitric Oxide |
| OCGT | Open cycle gas turbine |
| ODIN | Petroleum Reservoir Consultants |
| OEM | Original Equipment Manufacturer |
| OPEX | Operating Expenditure |
| PEM | Proton Exchange Membrane electrolyser |
| P2G2P | Power to Gas to Power |
| PtX,P2X | Power to X |
| Q3 | Third quarter of year, ending 30 September each year |
| QRA | Quantitative Risk Assessment |
| REZ | Renewable Energy Zone |
| SEM | Scanning Electron Microscope |
| Shmin | Minimum horizontal Stress |
| Shmax | Maximum horizontal Stress |
| SLB | A French-American oilfield service company, formerly known as Schlumberger |
| $Sm^3$ | Standard cubic metre |
| $SO_4$ | Sulfate Ion |
| SRW | Southern Rural Water |

| Abbreviation or Term | Description |
|---|---|
| STP | Sewage Treatment Plant |
| TCP | Technology Collaboration Programme |
| TJ | Terra Joule |
| TRL | Technology Readiness Level |
| UCS | Uniaxial Compressive Strength |
| UHS | Underground Hydrogen Storage |
| VTP | Victorian Transmission Plan |
| WEM | Western Australia's Electricity Market |
| WSTP | Warrnambool Sewerage Treatment Plant |
| WWRP | Warrnambool Water Recycling Plant |
| XRD | X-ray Diffraction |
| 1D | One Dimensional |
| 3D | Three Dimensional |

## 1. EXECUTIVE SUMMARY

The H2RESTORE Feasibility Study, supported by ARENA funding and led by Lochard Energy, explored the technical feasibility and commercial potential of underground hydrogen storage (UHS) in depleted gas reservoirs in Victoria's Otway Basin. This feasibility study represents a significant step towards enabling large-scale, low-cost hydrogen storage to support Australia's renewable energy transition by providing energy security for the National Electricity Market (NEM) and supplying emerging clean fuel industries.

The H2RESTORE Feasibility Study has been comprehensive, well executed and achieved the objectives for the study. Key findings were:

- UHS in the depleted gas reservoirs of the onshore Otway Basin is technically feasible.
- Early stakeholder engagement has made progress in building social engagement and support.
- The combination of concept select studies and techno-economic analysis found the business case may be achievable under favourable market conditions and with supportive policy mechanisms, although it is highly sensitive to future electricity market conditions, particularly the frequency and magnitude of price swings.
- Under favourable electricity price forecasts and with supportive mechanisms such as capacity payments and network charge waivers, the project can achieve a commercial internal rate of return.
- The most commercial configuration identified combines 200 MW of hydrogen production with 500 MW of hydrogen-fuelled generation and >6,000 tonnes of underground hydrogen storage and located at a single site (energy storage estimated at 96 GWh[1]).
- Economic studies have identified that UHS has the potential to reduce the cost of hydrogen by using the underground hydrogen storage to produce hydrogen during times of low electricity price.
- A depleted Lochard Energy gas field and reservoir have been identified for a potential UHS Demonstration Pilot with the Feasibility Study work across reservoir, surface facilities, landholder, and regulatory advanced sufficiently to support progression to Front End Engineering Design.

### TECHNICAL FEASIBILITY

**Subsurface Suitability:** Laboratory and field studies indicate that the Waarre C reservoir unit is a promising candidate for UHS, with robust caprock integrity and manageable geomechanical risks. Cyclic hydrogen injection and withdrawal have not shown evidence of compromising reservoir or caprock integrity under tested conditions.

**Geochemical and Microbial Safety:** Initial findings suggest low risk of adverse reactions or byproduct formation. Microbial studies highlight the need for improved sampling and ongoing monitoring, but do not identify immediate barriers to deployment.

[1] Energy available from storage assuming conversion to electricity

**Storage Capacity:** The subsurface field development planning demonstrated that the UHS system could deliver a commercial hydrogen working storage volume (WSV) with increasing purity and recovery under the chosen well configuration and control strategy.

**Replicability:** The methodologies and lessons learned are potentially transferable to other depleted gas fields in Australia and internationally.

## DEMONSTRATION PILOT READINESS

**Site Selection:** A preferred reservoir has been identified for a Demonstration Pilot, based on technical, logistical, and community factors. Further engagement with all relevant stakeholders including any affected landowners would take place prior to progressing with a pilot.

**Design and Costing:** A robust pilot concept is technically ready to progress to Front-End Engineering Design (FEED), with a clear cost and design basis. The reservoir has been assessed to use the minimum hydrogen mass necessary to achieve scientific and engineering objectives, with hydrogen delivered via high-capacity tube trailer identified as the lowest cost sourcing option for the anticipated volume (vs on-site electrolysis).

## COMMERCIAL PATHWAY

**Economic Modelling:** Techno-economic analysis suggests that commercial viability may be achievable under favourable market conditions with supportive policy mechanisms. Project returns are most sensitive to CAPEX, electricity price forecasts, network charges, and regulatory developments. Studies have shown the UHS has the potential to reduce the cost of hydrogen through the use of storage to access lower cost electricity likely generated during times of high renewable electricity generation and low demand.

**Cost Optimisation:** Consolidating hydrogen production, storage, and generation at a single site offers significant CAPEX savings and operational efficiencies.

**External Benefits:** UHS offers potential benefits for long-duration energy storage, grid firming, and decarbonisation, but these depend on evolving market and policy settings.

## SOCIAL LICENSE AND REGULATORY PROGRESS

**Stakeholder Engagement:** Early and ongoing engagement with local councils, First Nations representatives, landowners, and regulatory bodies has built a foundation for support for renewable hydrogen production and underground hydrogen storage.

**Regulatory Pathway:** The project has mapped required approvals and is collaborating with authorities to address legislative gaps as there is currently no framework to allow for the storage of hydrogen underground in Victoria. Regulatory pathways will require ongoing effort.

## REMAINING UNCERTAINTIES AND NEXT STEPS

While the feasibility study provides strong evidence supporting the technical and commercial potential of UHS in the Otway Basin, uncertainties remain. These include long-term reservoir

performance, operational optimisation, market conditions, and regulatory approvals. The potential Demonstration Pilot would support de-risking these uncertainties, provide critical data for commercial forecasting, and further build stakeholder confidence.

## CONCLUSION AND RECOMMENDATION

The H2RESTORE Feasibility Study has established a solid foundation for technical and commercial advancement. Progressing to a Demonstration Pilot would be the next step to resolve remaining uncertainties, validate key assumptions, and position the project for potential commercial deployment. Continued innovation, stakeholder engagement, and regulatory development will be essential to realise the full potential of UHS as part of Australia's cleaner energy future.

UHS within the H2RESTORE Project has progressed from ~TRL-3/4 to ~TRL-4/5 through the subsurface validation studies undertaken within the Feasibility Study. Demonstration Pilot operations would move it to TRL-6, with full commercial ramp toward TRL-7/8 with multi-year cyclic operation and market integration.

# 2. CONTEXT AND SCOPE OF THE FEASIBILITY STUDY

## 2.1 Context

The H2RESTORE Project is envisioned as a multi-phase initiative to repurpose depleted underground gas reservoirs near the Iona Gas Storage Facility (IGSF) for large-scale underground hydrogen storage (UHS). This project follows a pre-feasibility study conducted with CSIRO and Worley Consulting, which concluded that there is a low overall technical risk and recommended progression to a feasibility study. The feasibility study will inform possible investment decisions for the subsequent stages of the H2RESTORE Project, including a potential Demonstration Pilot and commercial deployment.

## 2.2 Scope

The feasibility study covered several key workstreams to evaluate the viability of the H2RESTORE Project:

1. **Subsurface Feasibility:** This involved assessing the feasibility of subsurface hydrogen storage in porous media through laboratory work on physical samples, advanced data processing techniques, and the development of specific models related to microbial, geochemical, geomechanical, and reservoir aspects.

2. **Surface Facilities:** Concept designs for both the pilot and commercial phases were developed, including revised cost estimates. The pilot design concept selected to provide key inputs for land access and approvals and be ready to proceed to Front-End Engineering Design (FEED).

3. **Technology Selection:** The study focussed on selecting the appropriate technology for hydrogen production via electrolysis and hydrogen fuelled power generation.

4. **Community and Environmental Approvals:** The study identified regulatory and approval pathways, confirmed water supply sources, and engaged with key stakeholders.

5. **Economic Assessment:** The study developed an economic model with refined capital costs, optimised inputs and assessed the commercial viability of the H2RESTORE Project. Additionally, an assessment of external benefits and a report on the macroeconomic benefits of large scale UHS were produced.

The outcomes of this feasibility study have provided a comprehensive understanding of the technical and commercial feasibility of the H2RESTORE Project, guiding the next steps towards its implementation.

## 2.3 Overview

The anticipated expansion of hydrogen production in Australia will require the parallel development of suitable storage options to buffer the fluctuations of supply and demand. At this scale, Lochard Energy believes that underground hydrogen storage (UHS) will be the most favourable option, for reasons of both cost and safety.

The geological possibilities for UHS are salt caverns, depleted gas fields, aquifers and hard rock caverns or mines. In the Australian context, salt deposits of suitable characteristics are only

present in some areas (e.g. Canning Basin, Officer Basin, Adavale Basin, Amadeus Basin), and there are no known deposits in the south-eastern states of Victoria and New South Wales [1] [2]. Thus, there has been interest in the possibilities for UHS in the onshore Otway basin depleted gas fields in Victoria which are close to market and high quality [3].

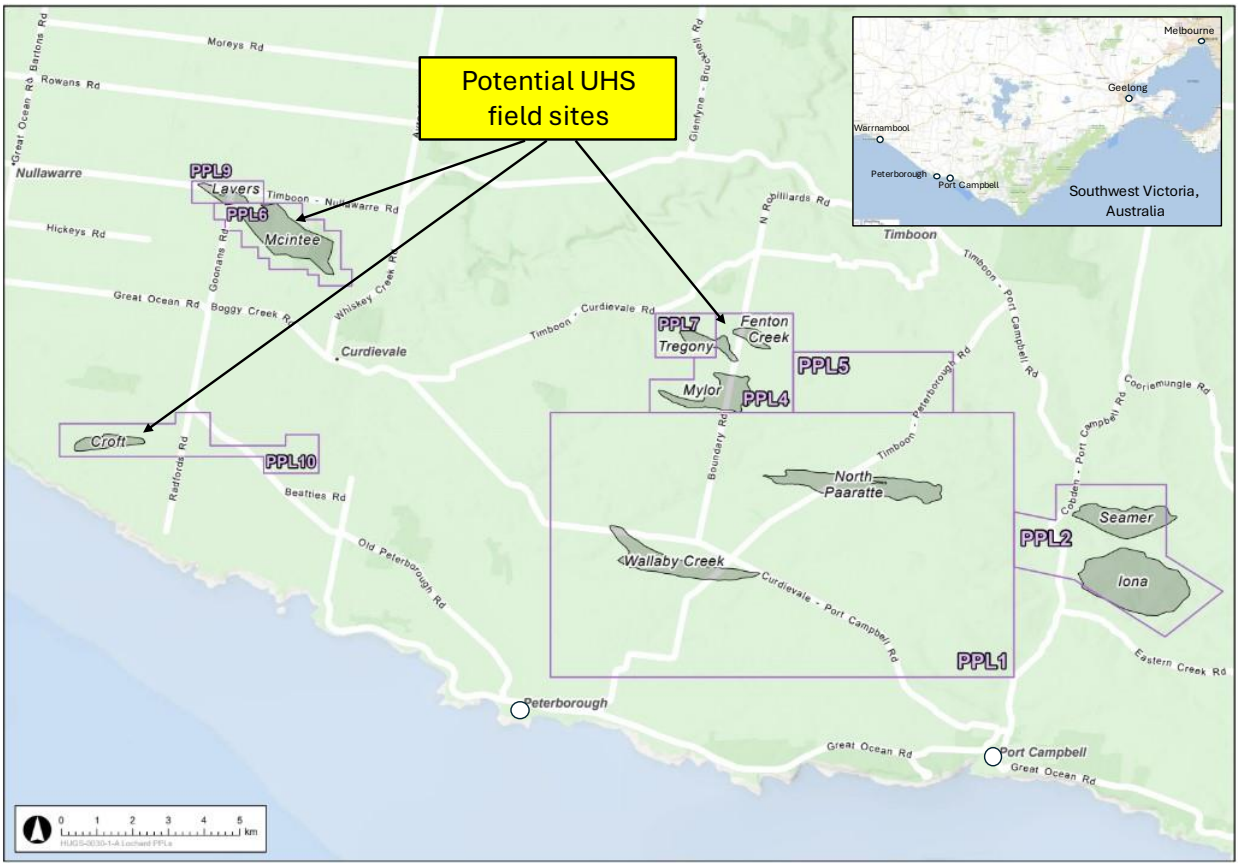



**Figure 1: Potential UHS field sites and existing UGS fields in the Port Campbell area, SW Victoria**

Since 2022, Lochard Energy has been considering the suitability of such existing gas fields for UHS (whether at pilot or commercial level), including the fields of McIntee, Lavers, Croft, Fenton Creek and Tregony. Figure 1 shows the geographical locations of these fields. Four of these legacy gas fields are operating underground natural gas storage reservoirs (Iona, Seamer, North Paaratte and Wallaby Creek) with a fifth field (Mylor) currently under development.

In 2023, Lochard Energy carried out pre-feasibility work on UHS in the Otway Basin, with CSIRO undertaking assessments of microbial, geochemical, geomechanical and reservoir engineering aspects of UHS. No significant risks were identified in this process, and recommendations were made for the next phase of work, being the feasibility study.

Based on this earlier work, Lochard Energy conceived the H2RESTORE Project to assess the potential to store hydrogen in its existing sandstone natural gas fields in the Otway Basin. Large scale underground hydrogen storage could reduce the cost of producing hydrogen by using low-cost electricity, likely generated during times of high renewable electricity generation and low demand. The stored hydrogen could be used as a deep energy reserve to support the National Electricity Market (NEM) during times of energy supply shortages. It could also provide a consistent supply of lower-cost hydrogen to the emerging cleaner fuels industry and other hard to abate sectors. Figure 2 is a depiction of how the potential project could generate and

store hydrogen to supply hydrogen-powered generation, the process industry and / or transportation sectors.

The initial development plan would be for a smaller scale UHS Demonstration Pilot located at one suitable field. This could be scaled up to a fully commercial facility with up to 500MW of electrolysers once high-confidence feasibility is demonstrated from a pilot. The preferred site for a commercial H2RESTORE facility has not yet been selected. Potential options to connect to the existing 500 kV or 220 kV transmission lines have been identified at existing terminal stations at Tarrone, Mortlake and Terang. Water requirements could be sourced and piped from industrial wastewater in Warrnambool or from deep aquifer sources. Refer Figure 3 for a map of the Feasibility Study area and energy infrastructure.

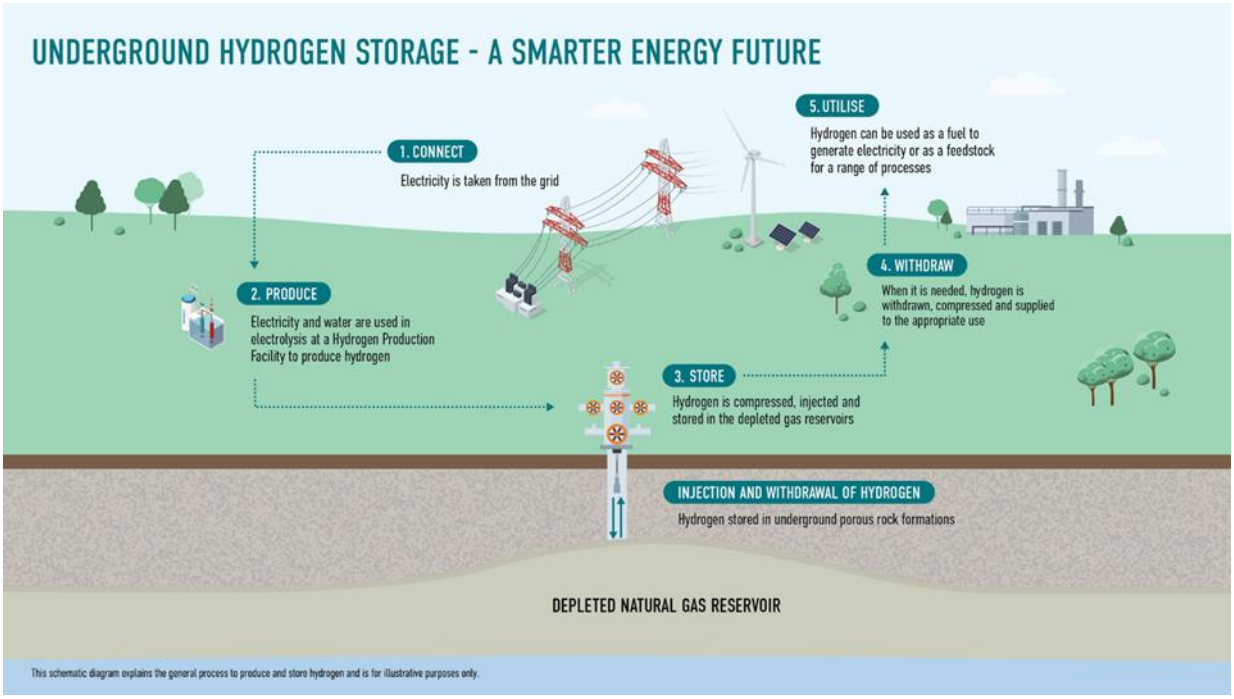



**Figure 2: Schematic of H2RESTORE Concept**

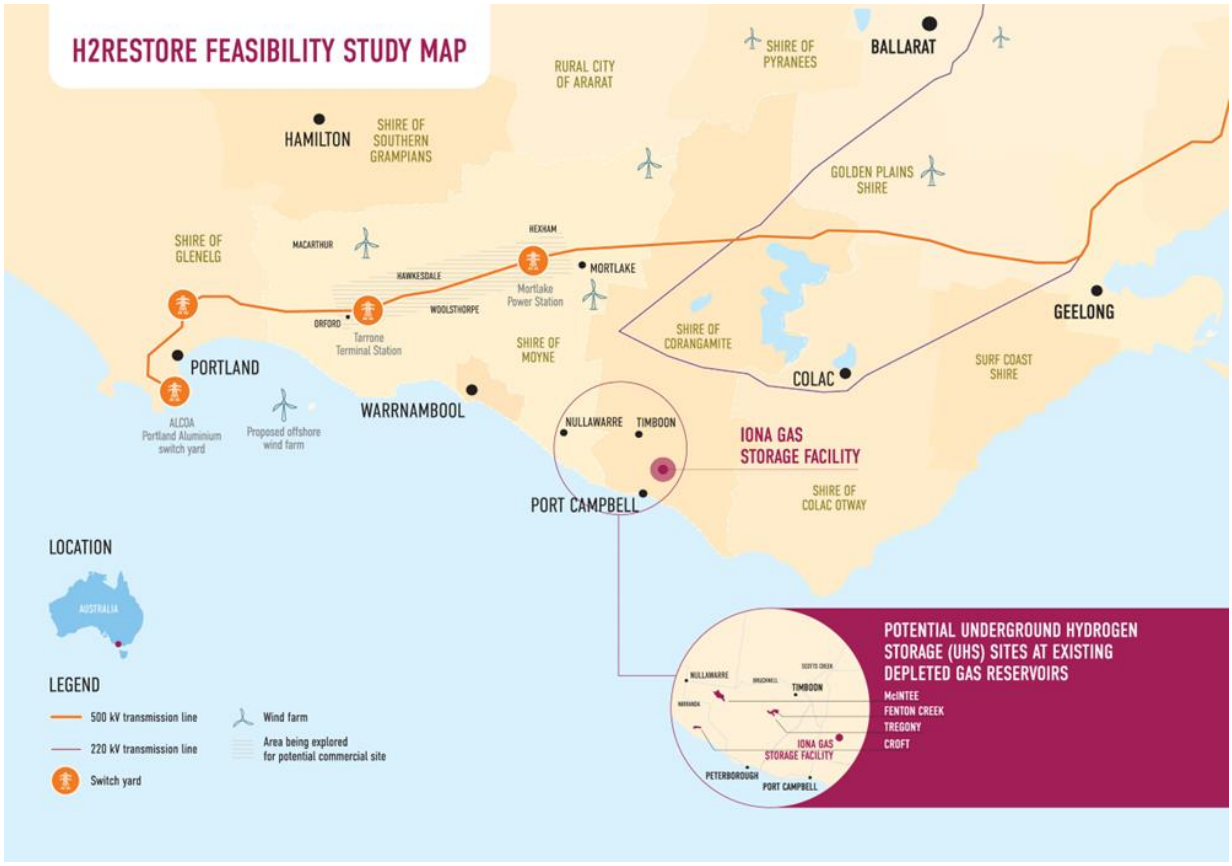



**Figure 3: Energy infrastructure in southwest Victoria**

## 3. SUBSURFACE SUITABILITY FOR UHS - RESERVOIR MODELLING, GEOCHEMICAL, GEOMECHANICAL AND MICROBIAL

CSIRO undertook workstreams across the key components within a subsurface system which are relevant to UHS and utilised information, data and samples available from Lochard and other sources specific to the depleted gas fields within the onshore Otway Basin. The workstreams include geochemical, microbial, geomechanical and reservoir assessment and align with the key challenges for large scale UHS in porous rocks described by Heinemann et al. [4] and the IEA Hydrogen TCP-Task 42 "Technology Monitoring Report" [5].

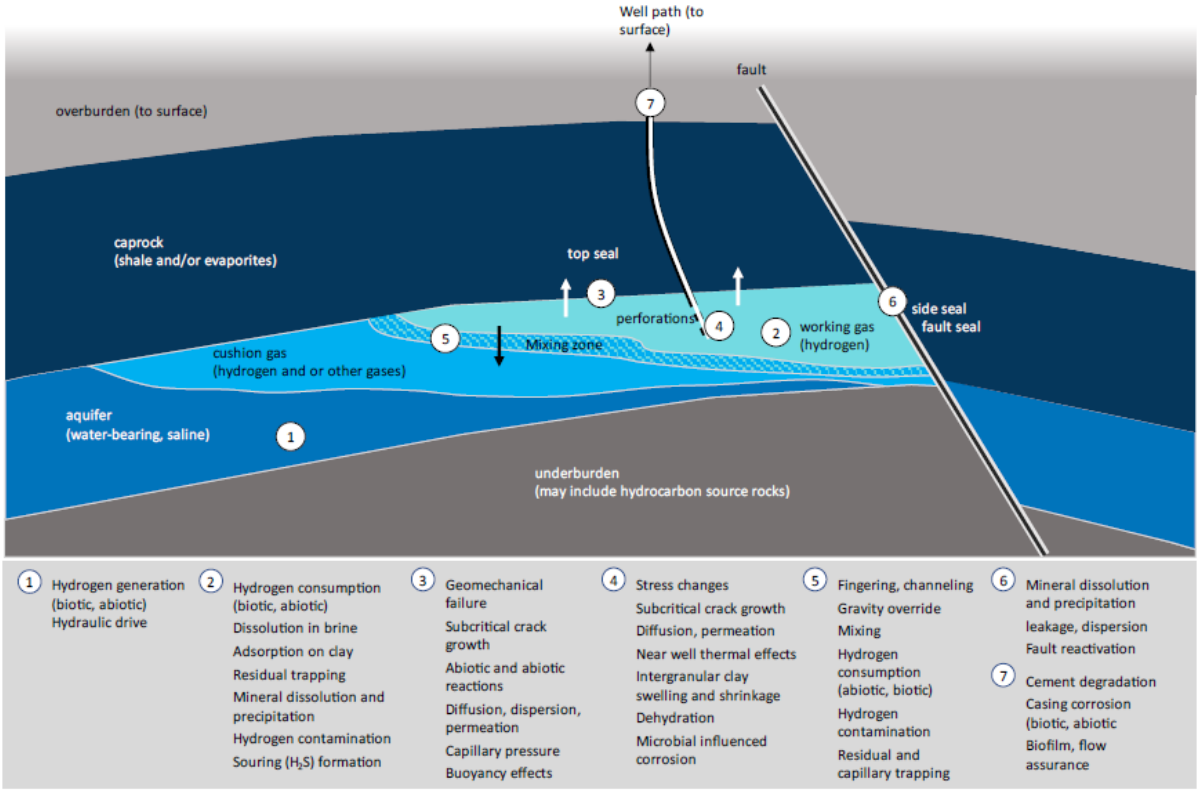



**Figure 4: Geochemical and microbial processes that impact underground hydrogen storage Ref: [5]**

## 3.1 Insights Microbial, Geochemical and Geomechanical

### Microbial

The microbial workstream report [6] aimed to understand any impacts from the interaction between hydrogen and the microbial communities in the formation waters within the reservoirs of the onshore Otway Basin. Key concerns were the potential production of $H_2S$ and the conversion of hydrogen to methane via methanogenesis. Due to the not being able to maintain live, viable microbial communities for laboratory testing after field sampling, it was not possible to fully understand the microbiological risk for the project.

The approach was to obtain formation water samples from representative depleted gas fields, conduct laboratory reaction experiments and to also conduct modelling of microbial effects during underground hydrogen storage. Two rounds of physical field sampling of formation waters were conducted during the study, with significant efforts made to minimise the potential for contamination by utilising specialised resources.

Laboratory experiments using formation water from McIntee and Mylor fields revealed that maintaining viable, representative microbial communities outside their native high-temperature, anoxic environments is extremely difficult. While core indigenous microbial species were able to be identified through DNA analyses (*Thermoanaerobacter brockii* and *Thermoanaerobacter kivui*), post-experiment analyses indicated that the microbial community in the waters were dominated by those typical of surface environment, versus the high temperature, anoxic environment of the subsurface, suggesting contamination and a microbial community not representative of the subsurface reservoir. This suggests that even brief deviations from in-situ,

subsurface conditions can dramatically alter microbial composition, making it hard to draw conclusions about actual reservoir processes.

Modelling work, using parameters from European UHS projects, suggests that microbial consumption of hydrogen (via methanogenesis or sulfate reduction) is most pronounced near injection points and can lead to hydrogen loss or $H_2S$ production, especially in $CO_2$-rich environments. While the current model uses microbial parameters from European UHS projects (due to limited Otway-specific data), its structure is designed to be updated as Otway Basin-specific microbial growth, yield, and population data become available. This ensures that the modelling provides a flexible, predictive tool for understanding and managing microbial risks in hydrogen storage. It bridges current knowledge gaps, guides future data collection, and supports informed decision-making for UHS development in the region, providing another tool to further de-risk this aspect of the subsurface across all the Otway fields.

**Geochemical and Cement**

No significant risks for UHS were identified in the Geochemical and Cement workstreams. The risks of hydrogen-induced cement or geochemical reactions with the subsurface formation, causing negative impact to UHS were considered low for the onshore Otway Basin gas fields and reservoirs studied. The details are comprehensively addressed in Sander et al. [7], with a high-level summary provided in this report.

Geochemical experiments demonstrated that hydrogen has minimal interaction with the rocks and fluids of the Otway Basin reservoirs [7]. The dominant mineral, quartz, remained chemically stable, and only minor changes in clay minerals and siderite were observed; these were attributed to water–rock interactions rather than hydrogen exposure. Pyrite, a potential source of hydrogen sulfide, showed negligible alteration, reducing concerns about $H_2S$ generation. Fluid chemistry analyses indicated that changes in ion concentrations were due to dissolution of pre-existing salts, not primary mineral alteration. Gas composition remained stable, with no evidence of hydrogen consumption via abiotic reactions. Cement integrity tests showed that hydrogen did not significantly affect unaltered cement, though deteriorated cement was more susceptible to pore structure changes, mainly due to water movement facilitated by hydrogen. Overall, the geochemical findings indicate a low risk of adverse reactions or byproduct formation under representative field conditions, supporting the technical feasibility of UHS in these settings.

**Geomechanical**

The geomechanical research was split across two workstreams - laboratory work and geomechanical modelling. Two reports by CSIRO [8] and SLB [9] provide a comprehensive, multi-scale assessment of the McIntee-Lavers field's suitability for underground hydrogen storage. The key findings support the technical feasibility of UHS in the Waarre C unit, with manageable geomechanical risks and robust caprock integrity. The work highlights the importance of mineralogical and mechanical characterisation, operational controls, and ongoing monitoring to ensure long-term storage integrity. The integration of high-quality laboratory data into field-scale geomechanical models is a key strength of this work. The iterative feedback and collaboration between experimental and modelling teams (CSIRO and SLB) ensured that the models were well-calibrated and that laboratory findings are directly relevant to operational scenarios.

CSIRO's report [8] delivers a comprehensive laboratory-based evaluation of the mineralogical, petrophysical, and geomechanical properties of both reservoir and seal rocks, before and after hydrogen exposure. It includes detailed experimental protocols, cyclic injection/withdrawal testing, and advanced imaging and mechanical testing, focusing on the impact of hydrogen on rock integrity and performance.

SLB's report [9] builds on the laboratory data, integrating it into field-scale 1 Dimensional Mechanical Earth Model (1D MEM) and 3D MEM. It uses these models to simulate the geomechanical response of the reservoir and caprock to cyclic hydrogen storage, including coupled reservoir-geomechanical simulations, risk analysis for caprock integrity, fault stability, and surface deformation. The work was highly complementary and together provide a robust technical foundation for assessing the feasibility and risks of UHS in the Otway Basin, specifically in the McIntee-Lavers field.

A key learning in this work stream was that in laboratory tests, mechanical properties of the main Waarre C reservoir unit showed resilience to hydrogen exposure, whereas in clay- and iron-rich units such as the Waarre A and B, hydrogen exposure has the potential to degrade mechanical properties. The degree of degradation is mineralogy-dependent, with smectite and siderite content correlating with greater wettability changes and mechanical weakening.

Laboratory tests also showed that hydrogen exposure causes rocks to shift from being water-wet to intermediate-wet, due to an increase in contact angles. This could influence hydrogen trapping and migration over time if reservoirs with more complex mineralogy are used for UHS.

The preserved Belfast mudstone tests demonstrate strong sealing capacity, with negligible hydrogen breakthrough and minimal alteration in pore structure.

Both reports confirm that cyclic hydrogen injection and withdrawal induce minimal permanent deformation in the reservoir and seals, with no evidence of mechanical fatigue or cumulative damage over the tested cycles. These assessments provide confidence in storage containment and in the suitability of the Waarre C-Belfast reservoir-cap-rock pairing for UHS.

## 3.2 Reservoir Assessment

Extensive subsurface analysis, modelling and forecasting was undertaken across the potential UHS fields to investigate the feasibility of UHS in the onshore Otway Basin. Refer Figure 1 for fields and locations. This work is summarised in the Reservoir Assessment Report [10] and the sections below with the individual workstream descriptions and report references provided in Table 1.

A preliminary screening of potential sites [11] and [12] identified the Fenton Creek gas field as a promising candidate for a pilot scale development, and the McIntee gas field as a promising candidate for commercial scale development.

Four workstreams were undertaken to further assess and investigate the Fenton Creek and McIntee depleted gas fields.

**Table 1: Reservoir Assessment workstream description**

| Workstream | Field | Description | Report Reference |
|---|---|---|---|
| **WS 1** | McIntee | Dynamic Reservoir modelling - History Match | [13] |
| | Fenton Creek | 3D Static Reservoir modelling | [14] |
| | | Dynamic Reservoir modelling - History Match | [15] |
| **WS 2** | McIntee | Dynamic Reservoir modelling – Initial field assessment, commercial scale UHS | [13] |
| | Fenton Creek | Dynamic Reservoir modelling – Initial field assessment, pilot scale UHS | [15] |
| **WS 3** | McIntee | Additional physics – temperature, permeability heterogeneity, relative permeability, dispersive mixing | [16] |
| **WS 4** | McIntee | Dynamic Reservoir modelling – Field Development Planning | [17] |
| | Fenton Creek | Dynamic Reservoir modelling – Fine Grid Modelling for Field Development Planning | [18] |

## 3.3 WS1-Compositional dynamic simulation model summary

**McIntee**

For WS 1 of the dynamic modelling [13], an existing history-matched dynamic model previously developed for McIntee in a black-oil formulation was converted to a compositional dynamic model that was suitable for modelling hydrogen injection and production. This involved a review of the static geological model, an investigation of how to represent hydrogen properties in the Eclipse 300 compositional model, and a conversion of the black-oil model to a compositional model, which was then history-matched to the existing field data.

**Fenton Creek**

A preliminary screening of potential sites [11], [12] identified the Fenton Creek gas field as a promising candidate for a pilot scale development. The Fenton Creek field is part of the larger Mylor-Fenton Creek-Tregony (MFCT) complex. Preliminary dynamic modelling work was performed to assess Fenton Creek as a pilot scale hydrogen storage site. Pilot scale is considered to be of the order 10s to 100s of tonnes of hydrogen, as opposed to a commercial scale project which may store 1000s of tonnes.

In WS 1 [15], an existing black-oil model of the MFCT complex was converted into a new compositional dynamic model. The static model creation is detailed in a separate report, Dance

[14]. It incorporated a new pillar grid for the reinterpreted horizons and petrophysical property modelling using sequential indicator simulation kriged on well properties.

The new dynamic model used a compositional fluid model for each field with 5 gas components to emulate the natural gas composition and hydrogen. The dynamic model was history-matched to the field data from all three fields in the complex, including pressure, gas injection rates and water arrival at the wells at various points in time. Overall, the new compositional model showed a good match to the field data, capturing the early-time production period and post-production recharge of the fields through the connected aquifers. Water encroachment at the wells was accurately predicted through the production periods, an improvement from previous models.

## 3.4 WS2-Initial field assessment summary

**McIntee**

For WS 2 of the dynamic modelling [13], the history-matched compositional model from WS 1 was used for the initial field assessment of McIntee for a commercial UHS development. This included an investigation of the hydrogen working storage volume, cushion gas requirements, and the performance of the reservoir under various injection/production scenarios. There is some overlap here with WS 4, which focuses on field development planning.

Two larger diameter injection/production wells (7-inch tubing) were found to be sufficient for the required rates, and locations were chosen at and near the top of the structure (this conclusion is re-visited in WS 4, with further discussion of velocity limits in the wellbores). Constraints on injection rates, field pressures and other operating parameters were agreed. Several initial injection scenarios were considered, depending on whether there would be secondary depletion of the natural gas still in the reservoir. The chosen strategy involved maximising the depletion of the remaining natural gas to lower the initial reservoir injection pressure and improve the initial cumulative injection volume. Additionally, a hydrogen injection strategy was implemented, controlling rates to stay below the original field pressure limit of 145 bar.

With this selected scenario, the first injection cycle was over 2 years. The agreed production strategy was to aim for an agreed energy output for producing 500MW electricity with an intermittent profile mimicking the fluctuating output from renewable sources. The reservoir as modelled was able to meet this energy demand over the withdrawal cycle – gas withdrawn initially had a high hydrogen content, which decreased slowly over the production cycle, with the natural gas content also contributing to the energy output. Nine injection and production cycles were simulated, and after these cycles the amount of hydrogen in the reservoir as cushion gas was determined, as well as the working storage volume which supported 96 GWh of electricity generation. The hydrogen content of the produced gas likewise increased over the cycles as hydrogen replaced natural gas within the reservoir.

Previous estimates of the total amount of stored hydrogen, based on static models of fluid displacement, were found to be reasonable when compared with dynamic simulations. The proportion of working storage volume to total volume was also comparable to estimates based on underground gas storage (UGS). The major contrast with UGS is that UHS can store only about one quarter as much total energy in the same reservoir.

### Fenton Creek

In WS 2, the history-matched compositional model from WS 1 was used for an initial field assessment of Fenton Creek for a pilot UHS development [15]. A numerically refined grid was created around the crest of Fenton Creek. The refined grid had a minimum grid cell size of 7.5 m lateral by 0.5 m vertical, refined from the initial grid size of 50 m lateral by 1–2 m vertical. Three new wells were created in the model to test various injection/production cycles and assess gas purity, working volumes and performance. Wells 1, 2 and 3 were placed 55 m, 65 m and 123 m in from the fault, respectively, downdip from the structural high in the model, in an effort to emulate realistic well drilling and geological uncertainty.

Before simulating hydrogen storage, the efficacy of a secondary depletion of the remaining natural gas from each well was tested, since the wells are up-dip of the original Fenton Creek-1 well and therefore had some remaining, producible native gas. Around 185 MMscf (5.24 million Sm3) of natural gas could be produced before water breakthrough at well 1. This is a small non-commercial volume of gas but producing it has several benefits over leaving it in place when performing the UHS, namely, the hydrogen gas stream is of higher purity, water breakthrough occurs more rapidly, and it allows for an initial model characterisation opportunity in the operation phase before beginning the hydrogen cycling within the UHS pilot.

The secondary gas depletion case was used as the base case for further simulations. Three cycles of injection and production were simulated at each well, for three nominal masses of 50 t, 100 t and 200 t. Effective injection rates were 1 t/d and production rates were chosen to provide production periods of ≈ 30 days in the first cycle to allow sufficient monitoring in the operations phase. After the initial injection, the produced mass of hydrogen was re-injected for subsequent injections, so the reservoir mass was always equal before each production period. For injection masses over 100 t, the reservoir was filled to a depth at least 5 m below the top of the perforations (for well 1).

The full report [15] details the scenarios and modelling outcomes. A representative snapshot is provided below in Table 2.

**Table 2: Snapshot of Fenton Creek injection, withdrawal, recovery factors and hydrogen purity**

| Injection mass (t) | Hydrogen injection cumulative (t) | Hydrogen produced cumulative (t) | Hydrogen Recovery factor cumulative (%) | Average Hydrogen Purity (%) |
|---|---|---|---|---|
| 50 | 81 | 39 | 48 | 31 |
| 100 | 178 | 101 | 57 | 47 |
| 200 | 402 | 271 | 67 | 61 |

Overall, Fenton Creek was found to be suitable, in terms of working volumes and purities, for a pilot-scale UHS project. A reasonable amount of the injected hydrogen was recovered, even at low injection quantities of 50 t, at relatively high purities. At this stage of the work, there was uncertainty around the results at small injection quantities. There was numerical dispersion in the results, even with the refined grid, that impacted mixing and the purity of the produced hydrogen. As part of WS 4 [18], a finer grid model was developed to address these issues, and to analyse the effect of the uncertainty around the topography and well placement. This work is discussed below in Section 3.6.

A pilot-scale UHS project aims to minimise hydrogen use to lower costs, since pilots do not generate profit and are conducted only to reduce risk for future commercial development. However, the behaviour of the pilot for small stored volumes is quite sensitive to details of the near-well environment, such as the top-seal topography and well positioning due to hydrogen being lighter and being expected to migrate towards the top of the structure. The rebuild of the static model with a newly interpreted structural model [14] was a crucial first step to improve the accuracy of the geological representation. The use of near-well refinement in the simulation grids was also essential for accurate dynamic modelling [18]. The final choice of the amount of hydrogen for pilot injection is then a balance between risk (the uncertainty in the reservoir performance) and cost (the purchase of the hydrogen). Smaller injection volumes are lower cost, but have a greater risk of inadequate performance, while larger injection volumes reduce the risk to performance, but increase the cost. The modelling in WS 4 provides a means to balance risk and cost, for the choice of performance goals.

## 3.5 WS3-Hydrogen specific investigations

The WS 3 report [16] built on the earlier modelling work on these two fields in WS 1 and 2 and considered the sensitivity of the results to four phenomena: temperature changes during injection, heterogeneity of permeability, relative permeability variations, and dispersive mixing.

The work on thermal effects considered first the change of temperature in the wellbore during injection, and then the influence of this within the reservoir unit. The magnitude of the temperature change in the wellbore was sensitive to flow rate, and also depended on the well design, such as the presence of an annulus between tubing and casing. For the likely hydrogen injection rate for a pilot UHS test, of the order of 1 t/day, the cooling in the wellbore was small, on the scale of 1-2 °C. For a commercial-scale injection, which could be 10-30 t/day of hydrogen, the cooling in the wellbore could be significant, on the scale of 10-20 °C. The influence of this cooling within the reservoir unit was largely confined to a radius of metres to tens of metres near the well, due to the thermal buffering of the formation rock. At a pilot scale the 1-2 °C cooling is not likely to have a significant effect on reservoir properties or geochemical or microbial processes. By contrast, the 10-20 °C cooling that could occur on commercial scale will add to the near-wellbore geomechanical stresses and could slightly reduce the maximum allowable injection pressure. More significantly, the cooling will reduce the rate of geochemical reactions in the near-wellbore region. The effect on microbial processes is more complex, as the cooling could reduce the rate of some processes and increase the rate of others, depending on their preferred temperature window. Further work is needed to understand these impacts in the commercial injection scenario.

To investigate the sensitivity to variation in permeability, a small set of representative geological alternatives were generated for the base static model of the McIntee field and approximately

calibrated to the historical data. The UHS performance on the commercial scale was found to be relatively insensitive to these permeability variations. There was an increase in the gas in place (GIP) of 1-2 % compared to the base case, an increase in injection capacity of 5-10%, and a slight decrease in hydrogen purity on withdrawal. Overall, the original gas-in-place (OGIP) and the extent of secondary depletion have a much larger effect on UHS performance than the variations in permeability.

The sensitivity study of relative permeability selected four variants which retained an acceptable match to the historical data for the McIntee field. Overall, the impact of the relative permeability variants on the working storage volume (WSV) was small, of the order of a couple of percent. There was a slight impact on gas mixing, where in the early withdrawal cycles the hydrogen purity could be up to 4% different to the base case but became more like the base case over subsequent cycles.

Gas mixing in dynamic simulations is influenced by three main factors: molecular diffusion, mechanical dispersion, and numerical diffusion. The report [16] outlines the theory of these effects and estimates their impact in different situations. Numerical dispersion is a phenomenon associated with grid discretisation in a simulation model, where its impact can be minimised by the reduction of grid size. Molecular diffusion and mechanical dispersion are actual mechanisms within the reservoir that require appropriate representation within the simulation model. Values of mechanical dispersion can be obtained by actual observations of injection and withdrawal, either in a pilot or commercial operation. Molecular diffusion, which is the random movement of molecules due to the collision with other molecules causing mixing, is dependent on reservoir pressure, temperature and composition of the bulk fluid. This mechanism may become important if UHS wells are shut-in for an extended period, allowing time for a layer of hydrogen within the reservoir to mix with the underlying natural gas. The study of this mechanism would need to be included in future dynamic simulation modelling.

Overall, the uncertainties due to heterogeneity and relative permeability variations were small, as long as the original gas-in-place was matched well enough. The thermal effects of injection will need more careful study at the commercial scale, since this could reduce the maximum injection pressure, and affect the rate of geochemical and microbial processes in the reservoir. Mixing processes are important for UHS in depleted gas fields, since they affect the purity of the hydrogen on withdrawal, and care needs to be taken in the modelling process. Ultimately the degree of mixing depends on field characteristics that could be measured with a tracer injection test.

## 3.6 WS4-Field development planning summary

### McIntee

In the WS 4 report [17], Sayyafzadeh et al. considered Field Development Planning (FDP) for UHS in the McIntee field, building on the outputs of the earlier workstreams. The results however are Recipient Confidential Information (RCI). For this reason, the summary here is limited to the approaches used, rather than the outcomes. The FDP established a base case design for McIntee that met a defined seasonal energy delivery target while remaining within original reservoir field limits and operational envelope constraints. Ten injection–withdrawal cycles were modelled, demonstrating that the system could deliver a substantial hydrogen working gas, or working storage volume (WSV) with increasing purity and recovery under the chosen well configuration and control strategy. The required well count depended largely on the design constraints on the

maximum flow velocity in the wells, and those constraints should be further examined in the next phase of the project.

Three additional factors which affect the storage performance were studied in this report: the extent of secondary depletion (SD) i.e. the further withdrawal of remaining native natural gas, the maximum injection pressure constraint, and the scheduling of hydrogen withdrawal. For the latter, a comparison was made between the base case, a single continuous high-rate period, and a continuous low-rate period. Further examination of the scheduling would require integration with a wider techno-economic model for the fluctuations in electricity supply and demand, and the overall energy context in which the project might operate.

The methodology is like that used for assessment of the underground gas storage (UGS), but there a few specific differences. The demand scenarios for UHS will differ from UGS, and that will strongly affect the requirements for the number of wells, and the operational envelope. Mixing of the stored hydrogen with the remaining native gas will affect the performance of UHS, depending on the use case, since the withdrawn hydrogen will contain some natural gas. For electricity generation (the use case mainly considered here), the native gas has greater energy content per reservoir volume, which is advantageous for turbine performance, but at the cost of CO2 emissions from the combustion. Over time, the natural gas is replaced with hydrogen with less native gas remaining in the reservoir after each cycle. The degree of mixing depends somewhat on the operational approach, but is largely influenced by how the injected hydrogen spreads out and disperses in the reservoir[2]. This can be measured by tracer tests in the field. This field data is essential for accurate predictions of hydrogen purity on withdrawal.

**Fenton Creek**

Reservoir modelling analyses in WS 1 and WS 2 for Fenton [15] demonstrated that the reservoir would be an appropriate candidate for a pilot hydrogen storage site. While this initial work demonstrated that multiple injection-withdrawal cycles at Fenton Creek would achieve the goals of the pilot, the cumulative hydrogen injection masses assessed for 3 cycles (80 to 400 tonnes of hydrogen) would impose a significant economic cost on any future Demonstration Pilot. The study also highlighted uncertainties associated with structure, hydrogen dispersion, well placement and completion length. The study by Jackson et al. [18] in WS 4 was designed to assess whether a smaller mass of hydrogen could meet the Pilot scientific and engineering objectives and investigate these uncertainties.

To address this, a high-resolution sector model was developed around the primary gas cap, using the established geomodelling workflow. Lateral grid resolution (12.5 m, 25 m and 50 m) and crest elevation (+/- 6 m) were varied to capture seismic imaging uncertainty, and all cases were history-matched to production and aquifer recharge to ensure appropriate representation of the real field history and observations. The study then forecast three cycles of hydrogen injection and withdrawal across progressively larger hydrogen inventories, reporting mean and range outcomes across a suite of realisations to bound uncertainty.

The modelling demonstrated that the pilot objectives for underground hydrogen storage (UHS) at Fenton Creek could likely be met with a nominal hydrogen mass of 30 t, requiring a cumulative

[2] Hydrogen dispersion is influenced by the reservoir geological properties and the flow dynamics of the gas

44 t over 3 cycles (range: 35.5 – 50 t). This was a conservative estimate based on recovery performance.

The modelling assessed the following insights:

**Well Placement and Perforations:** Shorter perforation lengths delayed water breakthrough and maximized recovery, especially for small injection masses.

**Structure and Permeability:** Both had strong impacts on hydrogen plume migration, recovery, and purity. Higher permeability increased plume spread and delayed water breakthrough but reduced purity.

**Storage Time:** Longer storage reduced recovery due to buoyant migration into the attic volume.

**Dispersion:** Numerical and physical dispersion coefficients were in line with literature; dispersion could be calibrated during pilot operations.

**Recovery Factors:** For 3 cycles, mean recovery factors ranged from 22% to 32% depending on the cycling scenario tested. The minimum recovery of greater than 0% was only achieved for masses greater than 30 t on the third cycle[3].

**Non-Monotonic Recovery:** Mean recovery was not a monotonic function of reservoir mass; small masses were more sensitive to local structure and dispersion, leading to high uncertainty and sometimes zero recovery.

**Purity:** Hydrogen purity in withdrawn gas increased with reservoir mass (mean 4% to 70% by molar volume for 1 – 200 t hydrogen, respectively) and was always above analytical detection limits.

As a result of the work, the following were identified for consideration in future work:

**Potential for Pilot Objectives Refinement:** If pilot objectives were modified (e.g., to focus on microbial or geochemical effects), much smaller hydrogen volumes could be tested, reducing cost and complexity. This also aligns with comments in section 3.1 on microbial.

**Well Placement and Perforations:** Careful selection of well location and perforation length is critical, especially for small-scale pilots, to avoid instant water breakthrough and maximise hydrogen recovery.

**Structure, permeability and dispersion:** Localised structure, permeability and dispersion have outsized impacts at small injection masses at the pilot scale. They must be well characterised, and where possible calibrated during the pilot operations. This information could also inform future large-scale projects.

**Pilot Flexibility:** The results support contracting for a minimum hydrogen supply with flexibility for higher volumes, as actual requirements may be refined based on pilot learnings.

[3] At lower tonnages of injection, the injected mass may not be large enough to prevent early water break through with the hydrogen quickly dispersing into the reservoir.

## 3.7 Recommendations and Conclusions

### 3.7.1 Microbial, Geochemical and Geomechanical

**Microbial**

The Microbial Studies for Underground Hydrogen Storage in the Onshore Otway Basin report [6] stresses the need for improved sampling protocols and in situ monitoring to better understand and manage microbial risks in underground hydrogen storage.

There is significant potential to enhance the understanding of microbial processes within the depleted gas fields of the onshore Otway Basin through the use of in-situ hydrogen reaction tests with specialised wireline-deployed reaction chambers. This innovative concept, which requires further investigation and implementation, could provide a low-cost pathway to gain valuable insights into the microbial dynamics and interactions within these fields.

**Geochemical**

The risks of hydrogen-induced cement or geochemical reactions with the subsurface formation, causing negative impact to UHS were considered low for the onshore Otway Basin gas fields and reservoirs studied.

**Geomechanical**

The preserved Belfast mudstone tests demonstrate strong sealing capacity, with negligible hydrogen breakthrough and minimal alteration in pore structure.

Cyclic hydrogen injection and withdrawal induce minimal permanent deformation in the reservoir and seals, with no evidence of mechanical fatigue or cumulative damage over the tested cycles.

The geomechnical assessments provide confidence in storage containment and in the suitability of the Waarre C-Belfast reservoir-cap-rock pairing for UHS.

### 3.7.2 Reservoir Assessment

The four workstreams that comprise the reservoir assessment provide an analysis of the suitability of two potential sites for UHS. The first site, Fenton Creek, was chosen as a potential pilot site because the small, steeply-dipping structure was initially assessed as requiring the smallest amount of hydrogen for a successful pilot test (based on static volumetric estimates). The second site, McIntee, was chosen as a potential commercial site for UHS for opposite reasons, namely that the large and shallow-dipping structure was initially assessed as allowing a large amount of stored hydrogen, which would make the storage economics more favourable.

For the potential commercial site, McIntee, a history-matched compositional model was developed as a starting point for simulating UHS scenarios. The chosen strategy was first to produce the remaining native gas (which was higher in the structure than the original production well), using hypothetical new wells drilled closer to the crest of the structure. The agreed production strategy was to aim for an agreed energy output for producing 500MW electricity with an intermittent profile mimicking the fluctuating output from renewable sources. The reservoir as modelled was able to meet this energy demand – gas withdrawn initially had a high

hydrogen content, which decreased slowly over the production cycle, with the natural gas content also contributing to the energy output. Nine injection and production cycles were simulated, and after these cycles the amount of hydrogen in the reservoir as cushion gas was determined, as well as the working storage volume which supported 96 GWh of electricity generation. The hydrogen content of the produced gas likewise increased.

This initial performance assessment for McIntee was relatively insensitive to variations in reservoir heterogeneity. Changes in original gas-in-place (OGIP) and the extent of secondary depletion (SD) were the largest factors affecting performance. Thermal effects of injection on the bottom-hole temperature could be significant for higher hydrogen injection rates, with cooling of the near-well region of the reservoir by 10-20 °C. Further work is needed to assess how much this affects the near-well stress distribution and thus the maximum allowable injection pressure, although an operational decision to stay below the discovery pressure would provide a good margin of safety on the typical maximum pressure limits. Near-well cooling may also influence geochemical and microbial reactions in complex ways, with potential to reduce the rate of some reactions and increase others and should be the subject of further investigation.

The final phase of work on McIntee WS 4 FDP demonstrated that the system could deliver a substantial hydrogen working storage volume (WSV) with increasing purity and recovery under the chosen well configuration and control strategy. The required number of wells depended largely on the design constraints on the maximum flow velocity in the wells, and those constraints should be further examined in the next phase of the project. A range of secondary depletion strategies and withdrawal schedules were considered. The FDP work was undertaken in parallel to the techno-economics (section 12, [19]), resulting in minor discrepancies regarding injection rate and sustainable WSV due to differing assumptions and methodologies used in each workstream. In future work, it is recommended to integrate the reservoir model with a broader techno-economic model. This will account for fluctuations in electricity supply and demand, allowing for more realistic hydrogen injection and withdrawal schedules.

## 3.8 Replicability and Transferability to other fields

The H2RESTORE project has concentrated on underground hydrogen storage (UHS) in onshore depleted gas fields in the Otway Basin in Victoria. As explored in Ennis-King et al. [1], there are onshore depleted gas fields in other parts of Australia that could be suitable for UHS, including in South Australia, Western Australia and Queensland. Offshore depleted gas fields could also be used for UHS but would likely be more expensive due to additional costs for wells, platforms and pipelines.

Ennis-King et al. [11] review and discuss the methodology for screening candidate depleted gas fields for UHS, including preliminary estimation of storage volumes based on static models. It has been demonstrated from the subsequent dynamic modelling (Ennis-King et al. [13]; Sayyafzadeh et al. [17]) that these preliminary estimates are a reasonable guide. Thus, this approach to screening for UHS sites should have applicability to other onshore depleted gas fields in Australia and elsewhere. The final dynamic modelling results for WSV as a proportion of total stored hydrogen should also be useful for site screening of similar reservoirs.

The screening process highlighted the differing requirements of pilot-scale and commercial-scale projects, which has more general applicability. For pilot-scale UHS, where there is a cost pressure to minimize the amount of hydrogen required, a small and steeply dipping structure is

preferred. For commercial scale, where larger storage amounts could improve the project economics, a large and shallow dipping structure is preferred. The presence of aquifer pressure support is also a key feature, since it enables the progressive use of larger depleted fields, while still maintaining deliverability for fast withdrawal. This style of gas reservoir is relatively common in Australia. By contrast, depletion-drive reservoirs (without aquifer pressure support) may require larger injection volumes to fill the reservoir and increase the pressure. This may lead to a larger proportion of cushion gas and additional compression requirements. These reservoirs can have some compensating advantages, such as higher recovery overall and less gas mixing.

One of the potential drawbacks of UHS in depleted gas fields is the mixing of the stored hydrogen with the remaining native gas in the reservoir. If high purity is desirable for the hydrogen on withdrawal, then either the working storage volume must be smaller (and therefore more hydrogen is kept as cushion gas), or the withdrawn gas needs to be purified, with obvious additional costs. The H2RESTORE Feasibility Study has assessed the particular use case, where the withdrawn hydrogen is fed into a turbine to generate electricity. The turbine specifications do allow for a wide range of mixtures between hydrogen and natural gas, and thus there is no need for a gas purification step. For this use, depleted gas fields are highly suitable for UHS. If the desired application for the withdrawn hydrogen requires high purity, e.g. producing other hydrogen carriers such as ammonia, then depleted gas fields would be less suitable unless purification were added to the surface processing facilities.

The reservoir modelling process for UHS used in this project builds upon standard approaches used in petroleum development, carbon capture and storage, and underground gas storage projects. A static geological model of the gas field is built at a suitable scale and resolution, and a compositional dynamic model is fitted to the historical production and pressure data. For a pilot-scale UHS, the focus of the development is on minimising the amount of injected hydrogen, and so the modelling process requires careful well positioning, fine-scale models, and detailed consideration of how subsurface uncertainties affect the estimation of required volume. The understanding of the modelling of gas mixing, via numerical diffusion, mechanical dispersion and molecular diffusion, is also important to improving predictions. This is particularly important if the pilot design aims for injected amounts less than the attic volume above the chosen well locations. All these issues will be applicable to pilot developments in other depleted gas fields.

Since pilot-scale UHS for three injection-withdrawal cycles looks to amount to 10s of tonnes of hydrogen (with a cost in the hundreds of thousands of AUD for the hydrogen alone, depending on transport costs), alternative pilot concepts have also been briefly discussed. A less complex and expensive UHS pilot could be done using an existing well with small amounts of hydrogen and focusing on assessing in situ geochemical and microbial reactions involving hydrogen. This might require the development of a dedicated downhole tool for monitoring hydrogen reactions.

For the commercial-scale UHS development, the modelling process is focused on predicting the ultimate working storage volume (WSV), and the ability to withdraw case at the required rate. Both these aspects are crucial to the project economics and share many features with the development of underground gas storage (UGS). The primary use case investigated across the reservoir workstreams is electricity generation via turbines at times when the spot price of electricity is high. This requires large withdrawal rates and multiple wells are needed to meet these targets. The design constraints on these wells (such as the limits on gas velocity) have

been studied in this project, but will need further refinement, since there is little industry experience with such wells for hydrogen. These issues will be common to other developments in UHS for depleted gas fields.

WS 3 indicated that the commercial-scale UHS was not especially sensitive to variations in permeability or relative permeability. At the average rates of injection anticipated for commercial UHS (of the order of 20 tonnes per day), the thermal effects of injection were shown to induce a cooling of 10-20 °C in the near-well environment in the reservoir. This could be significant for coupling to geomechanics and could also have an important effect on the rate of geochemical and microbial reactions. These effects are likely to be general in other depleted gas fields.

Overall, the subsurface reservoir modelling for H2RESTORE has set out a high-quality framework for assessing UHS in other depleted gas fields. Many of the issues found in this project and described above will be relevant to other such developments in Australia or internationally.

# 4. ELECTROLYSER SELECTION

## 4.1 Summary - Context, scope, methods

A review of available and emerging electrolyser technologies was completed with assessment against the criteria shown in Table 3 below. These metrics were used to assess the electrolyser technology types and select the most suitable for the intended operating conditions.

**Table 3. Electrolyser Technology Selection Criteria**

| Criteria | Influence on project |
|---|---|
| Technology Readiness Level (TRL) | Higher TRL provides greater confidence in the ability of the technology to be able to meet the project scale and reliability requirements, and provides confidence in equipment CAPEX and inputs to OPEX |
| Operating Pressure | Influences compression duty required to transport hydrogen via pipeline, or for injection into underground storage |
| Start-up and Shut-down duration | Wholesale electricity price is expected to fluctuate significantly throughout the day, therefore, to maximise hydrogen production during periods of low electricity price, fast start-up and shut-down is preferred |
| Turn-down | A technology with a high turn-down ratio would allow greater operational flexibility, potentially enabling rate reduction during high electricity pricing periods, rather than ceasing production entirely |
| Stack Electrical Efficiency | A higher efficiency will result in lower electricity consumption for a given hydrogen production rate, reducing the electricity cost components of OPEX |
| Stack Life | A longer stack life before refurbishment or replacement is required is preferred as this reduces OPEX |

## 4.2 Results and Conclusions

The H2RESTORE project's technology selection process identified high-pressure Proton Exchange Membrane (PEM) electrolysers as the preferred option for economic modelling, with

Alkaline Water Electrolysis (AWE) also considered. The choice is driven by operational flexibility and commercial readiness, while economic modelling highlights the importance of minimising electrolyser CAPEX and optimising operational parameters for best financial outcomes.

Anion Exchange Membrane (AEM) technology is still developing with the potential to offer the operational flexibility of PEM at a cost similar to AWE. An economic sensitivity case assessing reduction in electrolyser CAPEX could potentially

High pressure Proton Exchange Membrane (HP PEM) electrolyser technology was selected as the basis for economic modelling due to its fast response time, making it suitable for market pricing driven operation, as well as being proven at scale.

## 4.3 Insights

From the economic modelling exercise, the following insights were identified;

- Lower electrolyser capacity (and thus lower CAPEX) improves project IRR compared to larger base case configurations
- CAPEX for electrolysers is the largest component of levelised cost of hydrogen (LCOH) and electricity (LCOE); a 20% reduction in electrolyser CAPEX yields a 0.6% IRR improvement
- Standby and offline modes do not materially impact project economics
- PEM, AWE and AEM technologies should be retained as viable options as vendor-specific factors may outweigh technology differences

## 4.4 Recommendations

Pressurised PEM has been selected as the base case for the H2RESTORE project and this selection was taken forward into the Feasibility Study, however AWE should also be considered when engaging with vendors as differences in cost, performance and support is greater between vendors rather than the technologies.

The selection between Pressurised or Atmospheric operating electrolysers should be based on real world experience and confirmation of actual leakage rates (both internal and external).

## 4.5 Lessons Learnt

**PEM vs Alkaline (AWE) - Both Are Viable, Vendor Differences Matter Most:** PEM (Proton Exchange Membrane) and AWE (Alkaline Water Electrolysis) are both commercially available and technically suitable for large-scale hydrogen projects. Real-world performance, cost, and support can vary more by vendor than by technology.

**AEM could provide the best of both:** The development of AEM technology is advancing and has the potential to offer the performance of PEM at the cost of AWE.

**CAPEX is the Dominant Driver of Project Economics:** Electrolyser CAPEX is the largest single contributor to the levelised cost of hydrogen (LCOH) and electricity (LCOE). Driving down electrolyser CAPEX through vendor competition, technology learning rates, and project scale should be a focus of future project stages.

# 5. GRID CONNECTION AND ELECTRICITY SUPPLY

## 5.1 Summary

During the Feasibility Study, Lochard conducted several studies with AusNet [20], [21], [22] to evaluate grid connection options into the 500kV and 220kV transmission networks in southwest Victoria. Additionally, a grid connection enquiry was submitted to AEMO.

Initial grid connection options considered hydrogen electrolyser loads up to 600 MW, with potential scale up to 1000 MW. AEMO require that the largest credible contingency be limited to 600 MW [23], with loads above this requiring detailed assessment to determine acceptability and network operational security to minimise the impacts in the event of loss of connection. This would likely have been a driver of higher connection cost (duplication of lines, transformers), however, subsequent technoeconomic modelling [24] found that electrolyser size of 500 MW or less was best suited to the available storage capacity of the selected reservoir, hence this was not explored further.

Following the technoeconomic modelling result, the electrical connection concept was refined with the project configurations below being assessed further;

- Up to 500 MW electricity generation, or export, during periods of high prices/low renewable generation, with a 200 MW export option also assessed
- Up to 500 MW electricity load, or import, for hydrogen production during periods of high renewable generation/low prices, with a 200 MW import option also assessed

For a project site located within 10km of a suitable 500kV terminal station, connection via 2 x 132kV transmission lines into a switchyard containing 1 x 500/132kV transformer was identified as the lowest CAPEX option. This was adopted as the basis for the project cost estimate build up. Mortlake (MOPS) and Tarrone (TRTS) terminal stations were considered the most likely 500kV connection locations, with Tarrone being selected as the cost estimate basis due to the high competition for remaining connection space into Mortlake terminal station by other projects. Late in the study period, Lochard became aware of another potential 500kV connection point at a potential new terminal station east of Mortlake [25]. No formal work was undertaken on this location, but it may prove to be a promising connection point once the terminal station has progressed more.

Connection into the Terang-Moorabool 220kV line at Terang Terminal Station (TGTS) was initially rejected as a suitable connection point due to the lack of remaining connection space, however, was revisited as part of the consolidated/single site option investigation late in the study period. It was assumed that due to the connection constraints at Terang Terminal Station, a new terminal station could be constructed between Terang and Cobden. AusNet were engaged to perform a Grid Capacity Study [22] to confirm if the 220 kV line had sufficient capacity to accommodate H2RESTORE's load and generation configurations. This found that planned and operational BESS projects at Terang and Gnarwarre would likely compete with H2RESTORE for line capacity in both load and generation scenarios, and when these BESS projects are not online, 500 MW generation would be restricted by line ratings. A 220kV connection option into the Terang-Moorabool line is therefore only considered suitable for a P2X configuration that utilises 200 MW or less electrolyser load. Refer to Figure 5 for summary of results.

Techno-economic assessment found that network charges can account for up to 45% of the total electricity cost and, if removed (e.g. via subsidies or updated policies), improves project NPV by nearly 1%. MLF impacts were assessed and found to have a negligible impact during hydrogen production mode as average power price is low, therefore, lesser impact of a change in MLF during this mode, however, could potentially have a greater impact during electricity generation mode when average wholesale pricing is higher. A MLF of 0.9908, similar to other GPG facilities connected into the 500kV network was selected for the base modelling scenario which is not expected to vary significantly due to the nature of the generation modes of H2RESTORE i.e. when area generation is low and hence resistance losses through the transmission network are negligible.

**H2Restore Generating mode:**

| | H2Restore at 250MW (Gen) | | | | | | H2Restore at 500MW (Gen) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | TGTS and GWTS BESS at 0 MW | | | TGTS and GWTS BESS at 175 MW | TGTS and GWTS BESS at 350 MW | | TGTS and GWTS BESS at 0 MW | | | TGTS and GWTS BESS at 350 MW | |
| SW VIC %CF Wind / Temp | 10% | 30% | 60% | 5% | 5% | 10-60% | 10% | 30% | 60% | 5% | 60% |
| 5 °C | ✓✓ | ✓✓ | ✓* | ✓* | ✓* | × | ✓* | ✓* | ✓* | × | × |
| 10 °C | ✓✓ | ✓✓ | ✓* | ✓* | × | × | ✓* | ✓* | ✓* | × | × |
| 15 °C | ✓✓ | ✓✓ | ✓* | ✓* | × | × | ✓* | ✓* | ✓* | × | × |
| 20 °C | ✓✓ | ✓✓ | ✓* | ✓* | × | × | ✓* | ✓* | × | × | × |
| 25 °C | ✓✓ | ✓✓ | ✓* | ✓* | × | × | ✓* | ✓* | × | × | × |
| 30 °C | ✓✓ | ✓✓ | ✓* | ✓* | × | × | × | ✓* | × | × | × |
| 35 °C | ✓✓ | ✓* | ✓* | ✓* | × | × | × | × | × | × | × |
| 40 °C | ✓✓ | ✓* | ✓* | × | × | × | × | × | × | × | × |
| 45 °C | ✓* | ✓* | × | × | × | × | × | × | × | × | × |

**H2Restore Load mode:**

| | H2Restore at 200MW (load) | | H2Restore at 250MW (load) | | | |
|---|---|---|---|---|---|---|
| | TGTS and GWTS BESS at 0 MW | TGTS and GWTS BESS at 350 MW | TGTS and GWTS BESS at 0 MW | | TGTS and GWTS BESS at 350 MW | |
| SW VIC %CF Wind / Temp | 37% | 63% | 16% | 43% | 26% | 70% |
| 5 °C | ✓✓ | ✓✓ | ✓✓ | ✓✓ | ✓* | ✓* |
| 10 °C | ✓✓ | ✓* | ✓✓ | ✓✓ | ✓* | ✓* |
| 15 °C | ✓✓ | ✓* | ✓✓ | ✓✓ | × | ✓* |
| 20 °C | ✓✓ | ✓* | ✓✓ | ✓✓ | × | ✓* |
| 25 °C | ✓✓ | ✓* | ✓✓ | ✓✓ | × | ✓* |
| 30 °C | ✓✓ | ✓* | ✓✓ | ✓✓ | × | ✓* |
| 35 °C | ✓✓ | ✓* | ✓✓ | ✓✓ | × | ✓* |
| 40 °C | ✓✓ | × | ✓✓ | × | × | × |
| 45 °C | ✓✓ | × | ✓* | × | × | × |

Key
✓ = Pre-contingency ≤90%
✓ = Post-contingency ≤110%
* = Post-contingency runback required

Notes:
- H2 Restore unlikely to be generating at times of high wind output
- H2 Restore is expected to operate as a load at times of high wind output

**Figure 5. Results of 220kV connection capacity assessment showing significant restriction on H2RESTORE if generating at greater than 250 MW. Some limitations imposed if BESS projects on same line are charging at maximum capacity with low wind capacity factor.**

## 5.2 Results and Conclusions

Connection into the 500kV network, either via Mortlake, Tarrone, or Mortlake East terminal stations, is preferred over a 220kV network connection as the 500kV line has greater capacity, there is less risk associated with load and generation curtailment due to competing BESS projects, and MLF during power generation mode would be closer to unity. The 500kV network in South-West Victoria is also likely to see much more renewable energy generation through development of the South-West REZ, with 500kV double-circuit line upgrades and significant wind generation deployment being announced in VicGrid's VTP [26].

The selection of a split site, or combined site concept will drive the transmission line voltage (likely either 132kV, or 220kV) decision to optimise line losses.

A range of ancillary grid support services were explored including frequency support, system strength and minimum demand. System strength support services, such as via clutched generators (acts as synchronous condenser), would likely form part of a self-remediation scheme rather than provide an alternate revenue stream, and FCAS markets are already saturated and better served by BESS projects. Minimum demand support via flexible load has the highest potential as being a supplementary revenue stream, or may simply allow for reduced supply

tariffs during hydrogen production e.g. similar to the flexible tariffs proposed in the Distribution Network by Powercor [27].

## 5.3 Insights

The H2RESTORE project in P2G2P configuration is best suited to connection into the 500kV network, ideally via the potential Mortlake East terminal station. In this location, H2RESTORE is likely able to generate hydrogen during periods of surplus wind generation from the South-West REZ, and surplus solar Victoria-wide, without competition from BESS projects that could cause curtailment during hydrogen production or electricity generating modes.

Significant investment in the 500kV network and associated South-West REZ is evident in VicGrid's VTP – making this region and grid connection point the best candidate for a long duration energy storage solution such as H2RESTORE.

For a P2X only project with electrolyser load up to 250MW, connection into the 220kV network may be feasible - network constraints could impact the project under some conditions, however, underground storage inventory may be sufficient to negate these impacts.

When considering the split-site vs consolidated site concept, energy transport via pipeline is potentially higher cost than via powerline due to the need for additional water pipelines (not just a hydrogen pipeline) in the split-site concept. See Section 6 for further detail.

Minimum or flexible load appears to be the only viable ancillary grid support service that the project could offer which could manifest as lower or zero transmission tariffs that could benefit project NPV by up to 1%.

Large inverter based-load, such as H2RESTORE's electrolysers, will likely have a negative impact on system strength which would potentially require a self-remediation scheme which could be achieved through implementation of clutched generators (acting as synchronous condensers).

## 5.4 Recommendations

Monitor development of the Mortlake East terminal station to inform potential future connection options or site selection.

In the next project phase, consider more detailed dispatch modelling to better understand grid power flows and potential constraints, particularly as the timing of new projects and coal exit are better understood.

Monitor for development of grid minimum load support service requirements and compare with the potential benefits to the H2RESTORE project already assessed in the technoeconomic modelling sensitivity cases.

## 5.5 Lessons Learnt

**Grid Connection Point Selection is Critical:** The choice between 220 kV and 500 kV connection points has major implications for project capacity, scalability, cost, and exposure to network constraints. 220 kV connections (e.g., Terang) are subject to significant thermal and stability constraints, especially as more renewables and batteries connect. 500 kV connections (e.g.,

Mortlake, Mortlake East, Tarrone) offer more headroom but may have higher upfront costs and land requirements.

**Thermal and Stability Constraints are Dynamic and Binding:** The South-West Victoria network is already heavily constrained, especially at 220 kV. Constraints are temperature-dependent and can change rapidly with new generator or battery connections. Post-contingency runback schemes (automatic reduction of generation/load after a fault) are often required to avoid overloading lines, and would likely be required if H2RESTORE was to connect to the 220kV network.

**System Strength and Harmonics: Compliance, Not Revenue:** System strength is a compliance obligation, not a revenue stream. New connections must either pay a system strength charge or self-remediate (e.g., by operating turbines as synchronous condensers). Harmonic compliance and power quality studies are required for large inverter-based loads (electrolysers).

**Minimum Demand and Flexible Load = Strategic Value:** Large flexible loads (like electrolysers) are increasingly valuable for grid stability, especially during periods of minimum demand. However, there is not yet a formal market for this service—commercial models are still emerging.

# 6. WATER SUPPLY ARRANGEMENTS AND TREATMENT REQUIREMENTS

The H2RESTORE project requires a sufficient water supply to allow generation of hydrogen, via the splitting of water into hydrogen and oxygen using electrolysis, and for use during power generation that requires spray intercooling to improve power output and manage NOx emissions.

Recycling of wastewater was the obvious candidate for supply as this would not add demand to the existing water reticulation system. Recycled water is currently used for power generation in the region[4] and initial investigation identified sufficient capacity was likely available from Wannon Water's Warrnambool Sewage Treatment Plant.

Later in the study phase, a combined site concept was explored that included the extraction of ground water from the Dilwyn or Paaratte ground water formations. Preliminary review of available aquifer capacity and bore deliverability found that sufficient capacity is available (either from new water allocations, or through transfer from existing licence holders) and that sufficient flow rate is likely to be achieved without excessive bore count. Re-injection of effluent water into the deeper, more saline, Waarre formation was also reviewed and found to be of similar scale to existing re-injection wells in the area.

## 6.1 Summary

The water concept study's scope focused on evaluating the feasibility of using recycled water from the Warrnambool Sewage Treatment Plant (WSTP), delivered via a new Warrnambool Water Recycling Plant (WWRP), for hydrogen production and use during power generation. Methods included technical assessments of water supply reliability, treatment requirements, pipeline sizing, and cost estimation for two plant sizing scenarios (200 MW and 500 MW). The approach combined process flow analysis, assessment of water quality sampling results

[4] The Mortlake Power Station uses recycled water during summer operation (Recycled water - Wannon Water)

(provided by Wannon Water), and engineering design principles to ensure the potential system could meet stringent water quality and operational demands.

Later phase assessment of groundwater usage was limited to screening of potential water sourcing and re-injecting requirements for each facility sizing scenario and preliminary assessment of wider ground water zone impact. Flow rate data for existing bores in the area was reviewed to estimate the required bore count, as was the design of a Waarre groundwater zone reinjection well. A preliminary costing exercise was then conducted to assess the potential cost saving as ground water extraction and re-injection would remove the requirement for water supply pipelines

## 6.2 Results and Conclusions

The study found that the WSTP can reliably supply sufficient recycled water to meet the needs of the H2RESTORE Project, with projected inflows exceeding future demand. The potential two-stage water treatment process—initial purification at WWRP and final polishing at the Hydrogen Production Facility (HPF)—is necessary to maintain high water quality for electrolysis. Sizing analyses confirmed that the recommended configuration (two DMW units at 60% of rolling capacity, with adequate storage) would ensure uninterrupted hydrogen and power production. The report concludes that the concept is technically feasible, with robust design margins and flexibility to accommodate seasonal and operational variations.

Deep aquifer usage appears to be a viable alternative to waste water recycling as ground water salinity is low and aquifer thickness (analogue for bore deliverability, refer to Figure 6) is high in the single-site area. Existing bore deliverability in the area indicates that 2 bores could deliver sufficient water for the largest project configuration assessed (500MW electrolysis, 500MW power generation). A 3rd bore was included in cost estimates for redundancy purposes. Similarly, 2 re-injection wells (plus a 3rd for redundancy) appear to be suitable for the corresponding effluent flow rates. Sufficient water volumes are available either through upcoming auctions or through transfer from existing licence holders – of the 81.3 GL of ground water licenced by Southern Rural Water (SRW) in the Warrnambool Groundwater Management Area (GMA), only 36.2 GL was extracted[5]. SRW are also conducting further ground water entitlement auctions in November 2025 which will provide an indication of additional ground water interest and cost that can be incorporated into future H2RESTORE project phases.

[5] Southern Rural Water, *'Annual Ground Water Condition Summary 2024-2025'*, available at <link>

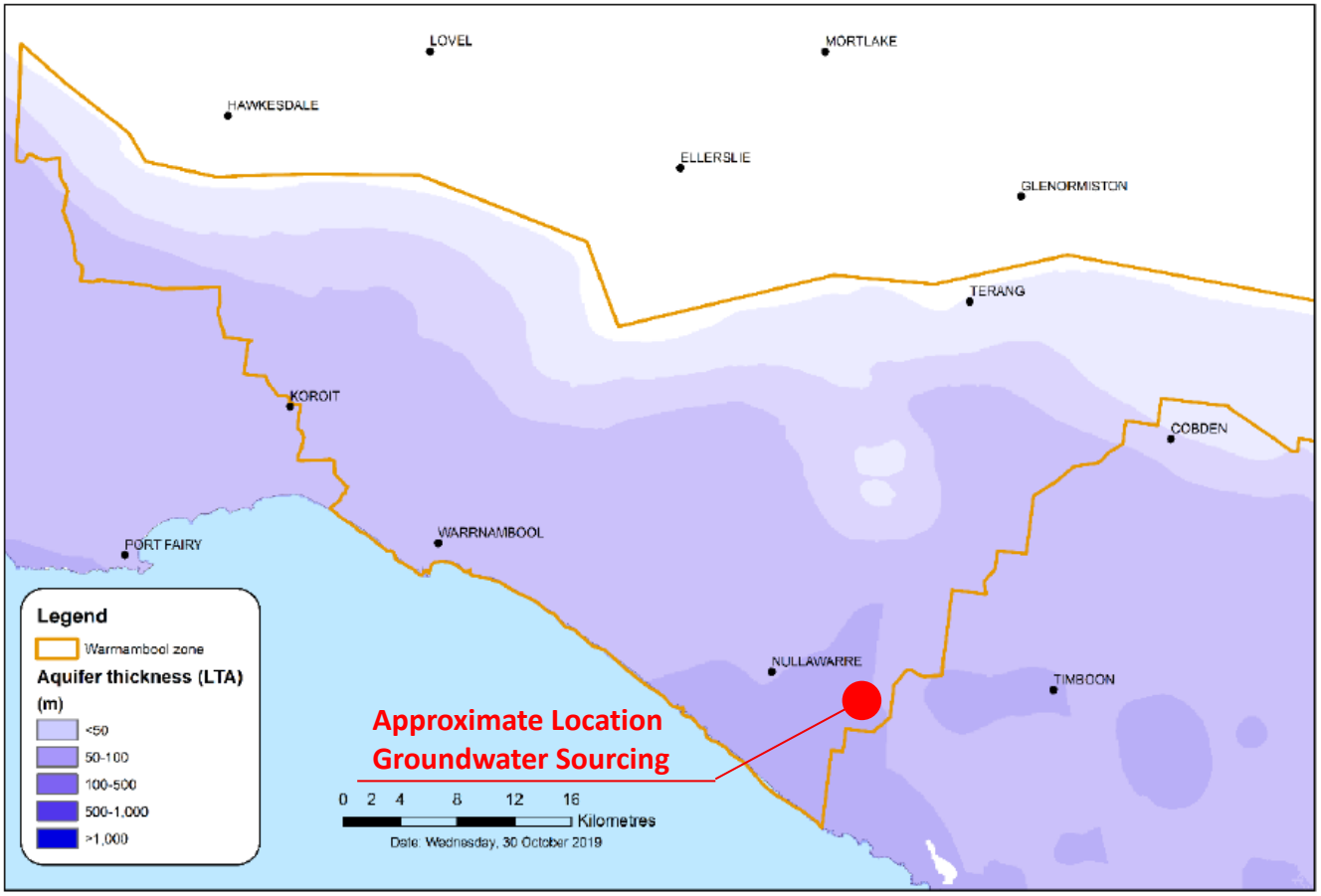



**Figure 6. Warrnambool Ground Water Management Area – Dilwyn Aquifer thickness**

## 6.3 Insights

Key insights from the Water Concept report include the importance of decoupling water treatment from hydrogen and power production to maximise reliability and operational flexibility. The analysis highlighted that water treatment costs are a small fraction of overall project costs, but water quality and availability are critical to project success. The study also emphasised the need for advanced pre-treatment and desalination processes, given the high and variable TDS in WSTP effluent. Collaboration with water authorities and ongoing sampling are essential to refine process design and ensure compliance with electrolyser vendor requirements.

The deep aquifer resource in the project area is very good (low salinity, high deliverability), surplus water appears to be available in the region and aquifer usage appears to be a lower cost option than off-site wastewater treatment that is transported via pipeline.

## 6.4 Recommendations

Perform further assessment of the deep aquifer potential at the project site by obtaining additional data from existing bores in the area to confirm water composition and bore deliverability (potentially through conducting drawdown tests). Once this data is available, develop a reference water treatment system design that can be costed. Assessment of effluent water disposal direct to ocean should also be considered as the predicted effluent salinity is below that of sea water.

If the recycled water options are to be progressed, further environmental and cultural heritage studies can confirm the suitability of the potential WWRP site. Continued engagement with Wannon Water is advised to finalise plant location and layout. Additional sampling and analysis of WSTP effluent are needed to optimise reverse osmosis recovery and process selection. Future project phases should involve electrolyser vendors to specify demineralised water quality requirements. The report also suggests considering opportunities for beneficial reuse of effluent and surplus water, as government agencies and water utilities are increasingly interested in recycled water and integrated reuse schemes to enhance water resource resilience as climate variability increases and pressure on traditional supply sources intensify. Projects like H2RESTORE could offer potential co-benefits and would align with local and state water agencies aspirations.

## 6.5 Lessons Learnt

Lessons learnt from the study include the value of early and thorough water quality analysis to inform process design, and the need for conservative assumptions when data is incomplete. The two-stage purification approach was validated as essential for maintaining water quality over long distances. The project team recognised the importance of building in design margins and redundancy to ensure reliability. Engagement with stakeholders, including water authorities and local communities, was identified as critical for project success and social license.

# 7. GENERATOR SELECTION

## 7.1 Summary

Several technologies are available for converting hydrogen back to electricity, each with varying efficiency, CAPEX and operational characteristics. Technologies assessed included:

- Open Cycle Gas Turbines (OCGT), including the following design subsets:
  - Aeroderivative turbines
  - Frame turbines
- Combined Cycle Gas Turbines (CCGT)
- Reciprocating Gas Engines
- Closed Cycle Gas Turbines
- Fuel Cells (including Solid Oxide Fuel Cells, SOFC)

The selection criteria shown in Table 4 was used to assess each generator technology which found Open Cycle Gas Turbine technology as the most suited to the intended application. Aeroderivative turbine designs were adopted as the base scenario with Frame turbine designs also considered in the event that time between start to full load is not considered critical.

**Table 4. Power Generation technology selection criteria**

| Criteria | Influence on project |
|---|---|
| Technology Readiness Level | Novel generation technologies not yet proved at large commercial scale would add risk that could jeopardise commercial viability |
| Generation Capacity per unit | Smaller capacity generators would require multiple units to achieve desired export capacity, requiring larger facility plot space and equipment replication that likely increases CAPEX |
| Fast Start Capability | Ability to provide fast-start generation may allow access to a greater number of extreme high pricing events that may not be easily predicted as is the case during normal generation scheduling and dispatch operations of the NEM |
| Generator Efficiency | Contributes to the P2G2P overall cycle efficiency – a higher efficiency will |
| Cost | Lower cost generators, all else being equal, will aid in project economic viability |
| $H_2$ Readiness | Operation on up to 100% $H_2$ is required to meet the facility design intent under the Power to Gas to Power configuration |

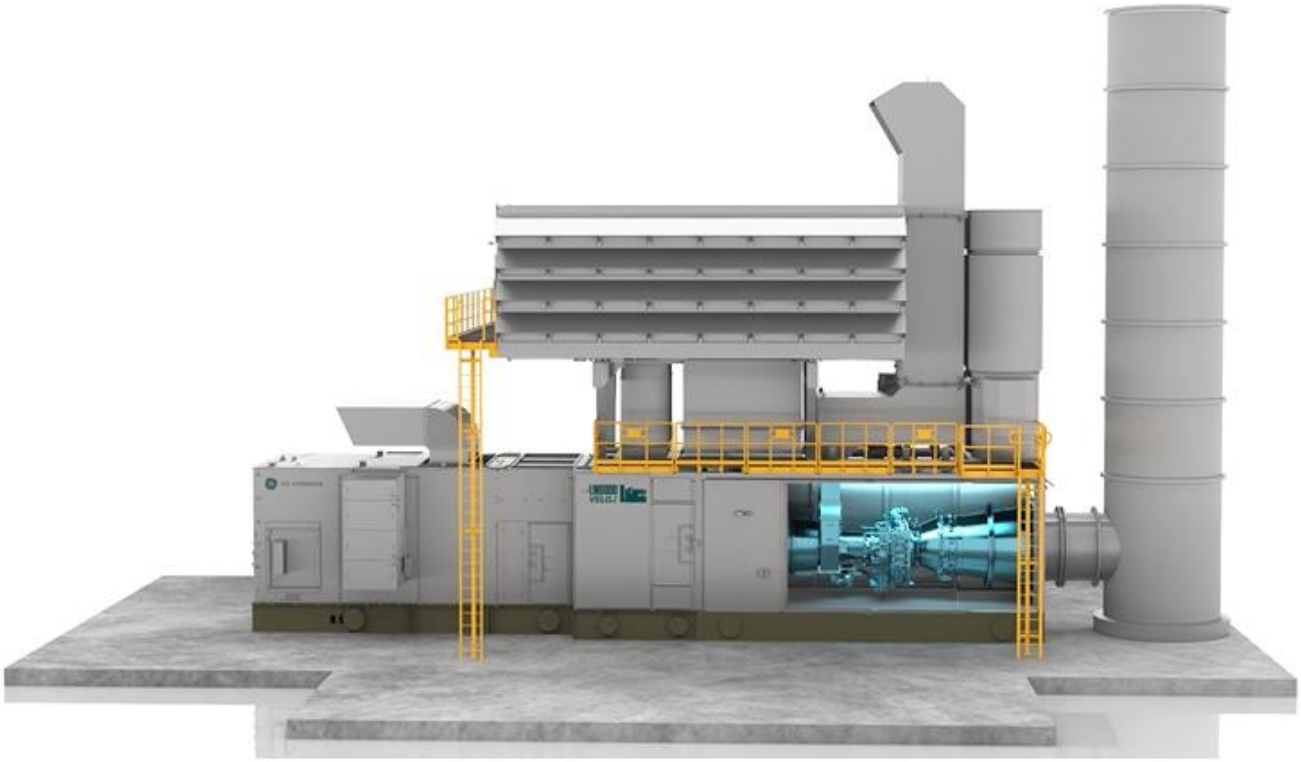


**Figure 7. GE Vernova's LM6000 aeroderivative gas turbine generator package**

## 7.2 Results and Conclusions

Aeroderivative OCGTs were initially chosen as the preferred technology for the following reasons:

- Fast response time is critical for market-driven, peaking power applications
- Maturity and availability at the required scale
- Lower capital cost compared to high-efficiency alternatives like fuel cells
- Flexibility and redundancy (multiple units allow for maintenance without full shutdown)
- Ability to operate on hydrogen (with ongoing development towards 100% $H_2$ capability)

Initial techno-economic modelling showed that OCGTs provided the best balance of CAPEX, OPEX, and operational flexibility for the project's arbitrage-based revenue model. Assessment of start-up delay was performed, with a 30-minute generator start delay showing a reduction in project IRR of 1%, which is considered significant. However, given that generally in the NEM, the trend of when prices are going to be high is predicted hours or more in advance based on the expected renewable generation and available BESS project storage, the expectation is that there would be very few occasions when the H2RESTORE project operator would be surprised by the timing of high pricing periods, allowing sufficient time to start the HPG and align dispatch with high pricing periods.

Frame turbines typically have approximately 30% lower CAPEX than aero-derivative turbines. However, they have a slower start to full load time compared to aeroderivative units. As the study evolved and further understanding of GPG dispatch requirements were assessed, the start-time was considered of lesser importance than CAPEX and so frame turbine technology was selected as the central case for final techno-economic modelling.

A sensitivity case assessing the impact of selecting Combined Cycle Gas Turbine technology found that the benefit of higher cycle efficiency is not sufficient to provide a more economic return due to the higher CAPEX, however, it is worth noting that the NPV difference compared with the most economic OCGT configuration was marginal (at only 0.2%).

Fuel cells were considered as a sensitivity case, however the modelling showed that the higher efficiency did not offset the much higher CAPEX, resulting in less favourable project economics.

### 7.3 Insights

The assessment highlighted that most project revenue is captured during short periods of exceptional power prices i.e. in the top 2.5-5% of NEM pricing, so fast-start (or sufficient scheduling to align start time to high price period) capability and flexibility are more valuable than maximum efficiency.

The impact of "real world" constraints (e.g., minimum run durations, standby loads, pipeline pressure cycling) was analysed, with OCGTs remaining robust under these considerations. The higher efficiency of CCGTs is not sufficient to overcome the additional CAPEX, however, if further technology development or cost reduction can be achieved in the future, this may make CCGTs a more viable option than OCGT technology.

OEM development of hydrogen capable turbines is still maturing and may impose some limitations on project design and operation such as requirement for startup on an alternate fuel source (either natural gas or suitable liquid fuel) and the required installation of exhaust treatment for NOx removal (allowance for which has been included in H2RESTORE project cost estimates).

The technology selection is to be revisited as the project progresses, especially as hydrogen turbine technology, CCGT and fuel cell economics evolve.

### 7.4 Recommendations

Continue to monitor development of OCGT hydrogen capability to confirm that technology development, particularly for startup on 100% hydrogen and low NOx emissions, progresses in-line with OEM expectations. If transient operation and low NOx operation can be achieved on 100% hydrogen, this has the potential to reduce CAPEX and improve operability.

### 7.5 Lessons Learnt

Operating an OCGT on 100% hydrogen is still technically challenging, particularly during transient conditions such as startup and shutdown. NOx emissions, even with spray intercooling technology, is likely still above discharge concentrations typically accepted for GPG facilities, unless supplementary exhaust treatment is included which adds cost.

## 8. COST ESTIMATE AND SCOPE FOR THE PILOT

### 8.1 Summary

A rigorous, multi-stage process undertaken to identify the optimal reservoir [11] and site for the Demonstration Pilot [12], culminating in a detailed concept design [28]. This process involved technical subsurface analysis, stakeholder engagement, regulatory planning, and engineering

design, ensuring that the selected solution is robust, cost-effective, and aligned with community and environmental expectations.

To facilitate and guide the work, a set of objectives was established for the Demonstration Pilot. These objectives were applied across all aspects of the surface and subsurface assessments and reports.

**Table 5: Demonstration Pilot Objectives**

| Category | Objective |
|---|---|
| **Safety** | Demonstrate the safe injection, storage and withdrawal of hydrogen in the Waarre C formation |
| **Verification** | Monitor and collect enough data that the pilot objectives can be verified |
| | Collect enough data to calibrate reservoir models to improve confidence for commercial field forecasting |
| **Risk reduction and confidence** | Demonstrate no 'showstoppers' in geophysical, geochemical, microbial and geomechanical subsurface interactions |
| | Reduce any potential commercial project risks to acceptable levels |
| **Timing** | Operate the pilot for a maximum of 2 years |
| | Minimum injection/withdrawal period of 1 week for sufficient data and physical sampling |
| | Minimum time between injection and withdrawal cycles of 1 month to demonstrate storage |
| **Cost** | Use the minimum mass of hydrogen necessary to achieve scientific and engineering deliverables |
| **Performance and Scalability** | Demonstrate acceptable injectivity and productivity over the cycling period |
| | Recover water samples at the end of each withdrawal cycle |
| | Complete a minimum of 3 injection / withdrawal cycles |

To obtain sufficient subsurface data to further de-risk any full-scale commercial facility, three hydrogen injection and withdrawal cycles would be planned. Removal of remaining natural gas from the reservoir prior to hydrogen injection showed a beneficial impact on total hydrogen quantity required and has been included in the scope of the Demonstration Pilot. A key focus around the hydrogen sourcing and use options are detailed in a separate technical note [29].

The short duration (~18-24 months) of the potential Demonstration Pilot, and relatively small quantities of hydrogen injected, favours a sourcing and withdrawal strategy that minimises CAPEX given that a pilot is not expected to make an economic return. This was found to involve delivery of hydrogen to site via truck and disposal via onsite flaring at a total cost ranging from AUD 35.1 million to AUD 42.7 million as shown in Figure 8 below [30].

Generation of hydrogen onsite via electrolysis was assessed, and although it provides a lower OPEX, it does not become the lowest cost option until greater than 900 tonnes of hydrogen injection is required (with initial subsurface modelling indicating between 80 and 400 tonnes of hydrogen would be needed for the pilot) [15]. Disposal via power generation was also assessed and found to provide insufficient electricity sales revenue to justify the additional equipment expenditure.

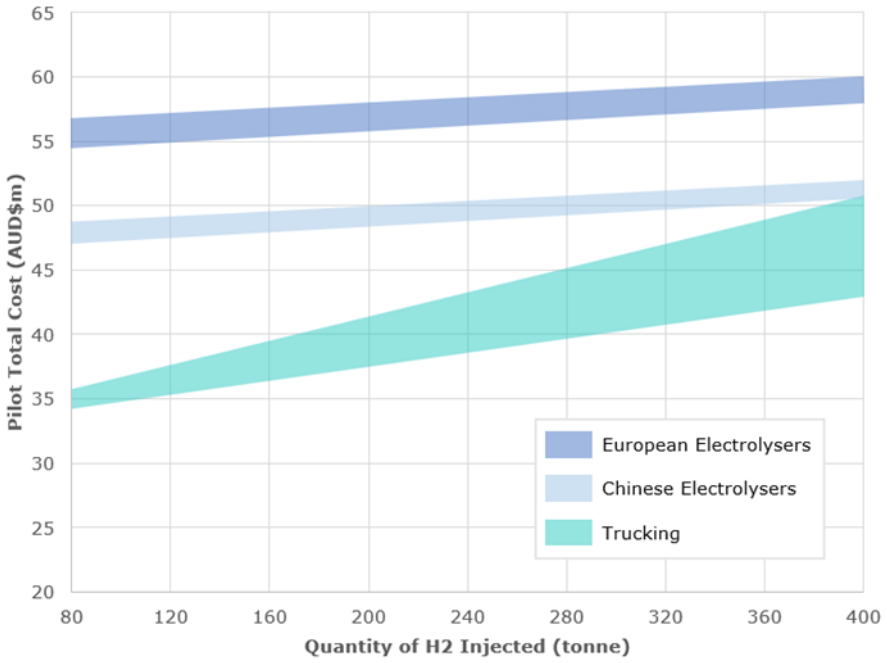



**Figure 8: Potential Demonstration Pilot total cost as a function of hydrogen sourcing options and injected quantity**

The potential Demonstration Pilot site layout requires ~0.7ha area and has prioritised separation distance to public roads and reduction of visual impact via site setback with entry via a single access road. Main equipment items for the selected trucking and flaring option include a hydrogen unloading compressor, test separator, flare and local electrical/control switch room. To minimise test separator vessel wall thickness and cost, a design pressure lower than well shut-in pressure has been selected, with suitable instrumented protective functions and relief valves used to prevent over-pressure.

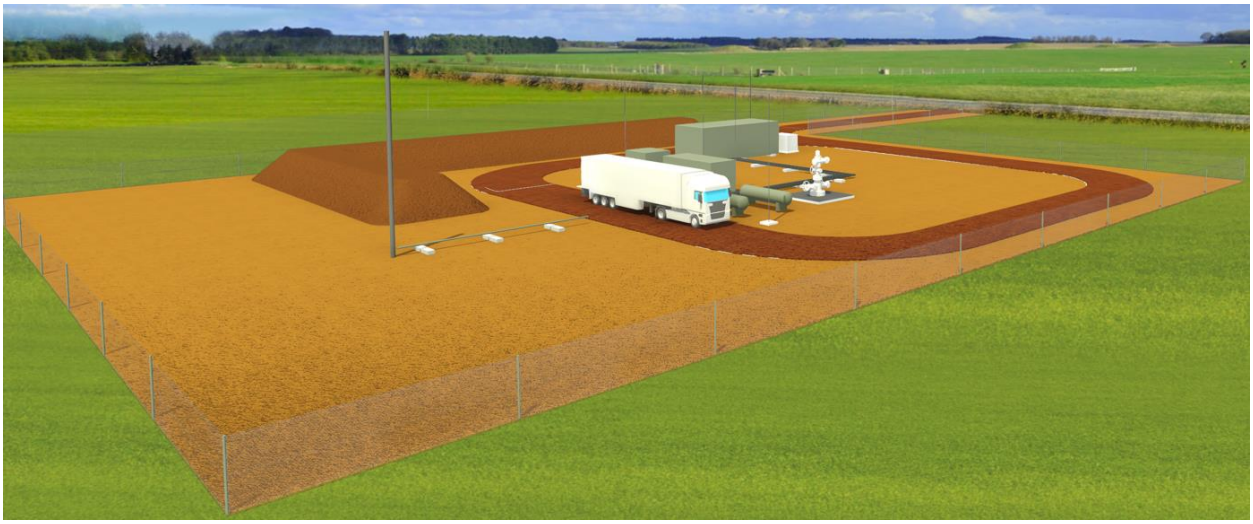


**Figure 9: Potential Demonstration Pilot conceptual layout**

The planned injection cycle operating philosophy aims to complete hydrogen transfer within a 12-hour day shift. The number of daily truck movements that would be required to drop-off full

and pick-up empty hydrogen tube trailers, would be adjusted as required to achieve the target daily injection quantity of ~1,000kg per day. Withdrawal operations would also be conducted during day-shift hours only, with the withdrawal rate adjusted as composition changes from 100% hydrogen to a hydrogen/natural gas blend to manage flare radiation intensity.

The feasibility study for the potential Demonstration Pilot identified a technically robust, lowest cost option for obtaining the required subsurface reservoir data to sufficiently derisk any full scale commercial project. From a technical perspective, the design is ready to progress to FEED for the potential Demonstration Pilot with a well understood cost and design basis.

The Demonstration Pilot Concept Select Report [28] provided a foundation for a number of supplementary reports – Fine Grid modelling at Fenton Creek [31] and reports in support of the MCA work and regulatory approvals. Pre-planning approval investigations across cultural heritage, ecological, climate change confirmed there were no significant impediments for the potential reservoir and locality.

As noted above, the early reservoir assessment work estimated pilot hydrogen cycling volumes at between 80 and 400 t. These volumes add a significant expense to the overall cost of conducting a Demonstration Pilot. The project team wanted to understand if a smaller volume of hydrogen could be used in the pilot and still meet the overall pilot objectives. The report - Workstream 4: Fine-grid modelling of a Pilot-scale UHS site at Fenton Creek, Otway Basin, Victoria [18] addresses this question and found modelling demonstrated that the pilot objectives can likely be met with a nominal hydrogen mass of 30 tonnes, requiring a cumulative 44 tonnes over 3 cycles (range: 35.5–50 tonnes). Other small-scale options for a UHS pilot are also briefly discussed.

## 8.2 Results and Conclusions

A methodical, transparent, and collaborative approach was taken to considering the requirements for a Demonstration Pilot. The work has:

- Investigated and de-risked a potential field and locality for pilot implementation.
- Developed a technically robust and viable concept design.
- Engaged with stakeholders and regulatory bodies to ensure alignment with best practices and community expectations.

Trucking hydrogen was identified as the preferred option for the pilot scale due to lower complexity and cost.

A compact, modular site layout was developed with a focus on minimising footprint and community impact. Safety studies (HAZID, consequence analysis, flare modelling) informed the design.

Detailed CAPEX and OPEX estimates were established for various scenarios.

The potential Demonstration Pilot is positioned to proceed to Front-End Engineering Design (FEED), with a clear technical pathway for further development.

## 8.3 Insights

The project's success in narrowing down both field and site options was due to a rigorous, iterative Multi-Criteria Analysis (MCA) process. This involved not just technical and economic factors, but also considered stakeholder sentiment, environmental and heritage considerations, and regulatory pathways. Early and ongoing collaboration between subsurface, engineering, regulatory, and community engagement teams was critical. This approach ensured that technical feasibility is balanced with social license and regulatory certainty.

The concept design phase evaluated multiple hydrogen sourcing and withdrawal options (trucking, electrolysis, flaring, power generation), with decisions made based on both current economics and operational simplicity. For novel demonstration-scale projects, simplicity and modularity (e.g., trucking hydrogen rather than building on-site electrolysis) can reduce cost, complexity, and regulatory burden. However, the design leaves open the possibility of scaling up or switching to more advanced options as the market and technology mature.

Detailed breakdowns were developed for CAPEX, OPEX, and decommissioning costs for each scenario, including sensitivity to hydrogen quantities and supply options.

The concept engineering embedded regulatory planning and safety studies (HAZID, consequence analysis, flare modelling) from the earliest stages, not as afterthoughts. Early integration of regulatory and safety considerations into project design can identify potential showstoppers and streamline the path to approvals.

The detailed, scenario-based approach to site selection, technical design, and risk management offers a blueprint for similar projects, highlighting the importance of flexibility, community engagement, and leveraging existing assets.

# 9. COST ESTIMATE AND SCOPE FOR COMMERCIAL DEVELOPMENT

## 9.1 Summary

**Context**

As noted earlier, the H2RESTORE Project aims to commercialise large-scale underground hydrogen storage (UHS) in depleted gas reservoirs in southwest Victoria, Australia. The project could support the National Electricity Market (NEM) by providing deep energy reserves, enabling cost-effective hydrogen production using surplus renewable electricity, and supplying hydrogen to emerging clean fuels industries and hard-to-abate sectors. The project could form part of Australia's broader energy transition and the Feasibility Study was supported by ARENA funding.

**Scope**

Worley Consulting was engaged to develop the design of the surface facilities, evaluate alternatives, address technical and operational challenges, and establish the capital cost range. This work was complemented by the subsurface studies being undertaken by CSIRO and social license and regulatory approvals activities by other specialist consultancies.

The project's initial commercial concept select investigated the following components. As noted in section 12, a number of these components were further evaluated. This section primarily reports on the initial commercial concept as reported in [32] and [33]:

- Hydrogen Production Facility (HPF): Electrolysis-based hydrogen production (200–500 MW scale), with associated power generation (200–500 MW) using hydrogen-fuelled open cycle gas turbines.
- Hydrogen Storage Site (HSS): Injection and withdrawal of hydrogen into/from a depleted gas reservoir, with a storage capacity of ~6,700 tonnes $H_2$.
- Water Recycling Plant (WWRP): Utilising recycled water from the Warrnambool Sewage Treatment Plant for electrolysis.
- Pipelines: Hydrogen and water pipelines connecting the HPF, HSS, and potential Power-to-X (PtX) users in Portland.
- PtX Supply Option: Supplying hydrogen to industrial users (e.g., Portland) as an optional, parallel scope.

**Methods**

Techno-Economic Modelling [24]: Multiple project configurations were modelled, focusing on arbitrage revenue (buying low-cost electricity, selling high-value electricity/hydrogen).

Engineering Design [32]: Worley Consulting developed concept designs for surface facilities, pipelines, and water systems, with CSIRO leading subsurface studies.

Cost Estimation [33]: AACE Class 4 capital cost estimates were prepared for various scenarios, including sensitivities for electrolysis capacity, power generation technology, pipeline sizing, and number of wells. The development of cost blocks allowed for multiple cases to be built for sensitivity analysis.

**Table 6: Sensitivities assessed**

| Facility component | Central case | Sensitivity case | | |
|---|---|---|---|---|
| Electrolysis Capacity | 500 MW | 200 MW | | |
| Water treatment | For 500 MW of HPF | For 200 MW of HPF | | |
| Power Generation Capacity | 500 MW | 200 MW | 300 MW | 600 MW |
| Power Generation Technology | Aero derivative | Frame | | |
| Number of wells | 2 | 3 | | |
| Hydrogen storage pipeline | DN450 | DN300 | DN500 | DN550 |
| PtX pipeline | None | DN150 | DN200 | DN250 |
| Water Supply pipeline | DN355 (14") | DN228 (11") | | |
| Water Return pipeline | DN160 (6") | DN125 (5") | | |
| Compressor sparing | Spare | No Spare | | |

Risk and Safety [34]: HAZID workshops and consequence modelling were conducted to identify and mitigate operational and community risks.

Stakeholder Engagement: Ongoing collaboration with water authorities, equipment vendors, and regulatory bodies.

## 9.2 Results and Conclusions

The early techno-economic modelling found that 200 MW electrolysis capacity that operated at a higher utilisation rate could optimise project economics with higher returns than the larger 500 MW concept. This conclusion is influenced by electricity price forecast, storage capacity and capital cost of electrolysis.

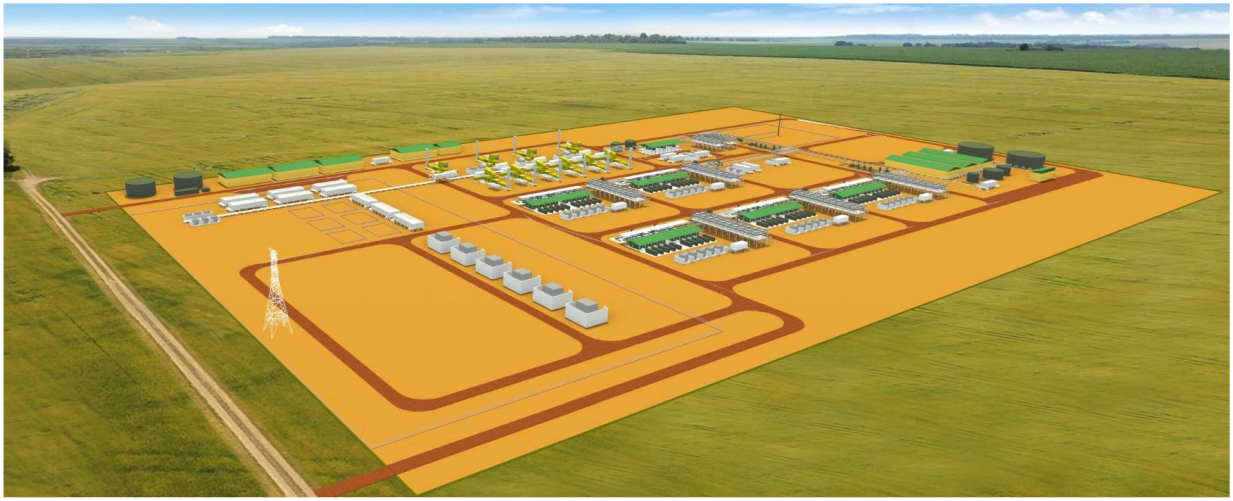


**Figure 10: 3D artistic impression of the HPF (500MW). Approximate area of 44 hectares.**

Ongoing development into electrolysis technology is expected to result in cost reductions between now and the time this project could be developed i.e. mid 2030's. Ongoing engagement with vendors is required to confirm the most suitable electrolysis technology. Costs can vary significantly between vendors due to standardisation of design, scale, improved production techniques, and lowering of precious metal usage. Currently, there is also a large cost difference between European and Chinese vendors. Chinese PEM electrolysers offer significant CAPEX advantages (currently 2–3x cheaper than European suppliers).

Frame turbines are ~30% cheaper than aero-derivatives but less flexible for intermittent operation. Aero-derivatives are preferred for fast response, but the final choice depends on the expected mode of operation and future electricity market conditions.

The addition of a clutch between turbine and generator allows the operation of the generator as a synchronous condenser to provide grid strength, which involves disconnection of turbine from generator, allowing the generator to remain connected to the grid generating or absorbing reactive power. This mode of operation may provide an additional revenue stream for grid support.

Pipeline Design: The original high-pressure (180 barg) hydrogen pipeline concept was found technically unfeasible due to cyclic fatigue. The revised design used an 80 barg MAOP, requiring

additional compression at the HSS but reducing pipeline costs. Pipeline design and cost remained a significant concept uncertainty at the conclusion of the commercial concept and was further reviewed in the final project economics, section 12.

Water Management: The concept study assessed the use recycled water for electrolysis, with advanced treatment and storage to balance intermittent operation. Effluent reuse (e.g., for agriculture) is recommended to reduce return pipeline costs. Again, this was reviewed in in the final project economics, section 12.

Cost Estimates: The development of cost blocks allowed multiple cases to be built for scenario analysis. Out of all the permutations investigated total installed costs for five cases were built up from the cost block data. These focused on the capacities of the electrolysers, and the capacity and technology type of the power generators as these cost blocks demonstrate the biggest cost impact.

The five cases were:

- 500 MW of electrolysis with 500 MW of Aero technology power generation
- 500 MW of electrolysis with 500 MW of Frame technology power generation
- 200 MW of electrolysis with 500 MW of Aero technology power generation
- 200 MW of electrolysis with 500 MW of Frame technology power generation
- 200 MW of electrolysis with 200 MW of Aero technology power generation

**Table 7: Summary of Total Cost - 5 scenarios in AUD million (2025)**

| Case | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **HPG Capacity (MW)** | 200 (aero) | 500 (frame) | 500 (aero) | 500 (frame) | 500 (aero) |
| **HPF Capacity (MW)** | 200 | 200 | 200 | 500 | 500 |
| **Total Cost (AUD million)** | 1,588 | 1,919 | 2,235 | 2,402 | 2,718 |

PtX Supply: The cost to supply hydrogen to Portland (PtX) is estimated at AUD 100–125 million, including purification system and additional pipeline depending on pipeline size and hydrogen rate.

### Conclusions

Technical Feasibility: The concept is technically robust, with no unmitigable hazards identified. The project leverages proven technologies and existing infrastructure.

Economic Viability: Project returns are sensitive to electrolyser capacity, utilisation rates, and electricity price forecasts. Smaller, highly utilised electrolysers are more economically attractive. Noting the project economics were updated again post the concept study.

Flexibility: The project is designed to accommodate both grid support (arbitrage) and industrial hydrogen supply (PtX), allowing for staged or parallel development.

Cost Drivers: Electrolysers and power generation are the largest CAPEX components; pipeline and storage costs are relatively modest in comparison.

Risk Management: Key risks (pipeline fatigue, NOx emissions, water supply, community impact) are identified and manageable with further engineering and stakeholder engagement.

## 9.3 Insights

Higher utilisation of smaller electrolysers yields better returns than simply scaling up capacity.

Early engagement with electrolyser and turbine vendors can potentially unlock cost savings and inform technology selection.

The project could provide valuable ancillary services (e.g., synchronous condensing, minimum demand backstop) to the NEM, potentially creating new revenue streams.

Combining HPF and HSS at a single site (near the reservoir) could reduce costs and technical risks associated with long hydrogen pipelines. Refer to section 12 for a further assessment of this.

## 9.4 Recommendations

The following recommendations emerged from the Worley Concept Select Report [32] for the commercial phase which was completed midway through the Feasibility Study period. Many of these recommendations were considered and assessed by the later and second phase of techno-economics undertaken by Worley [19].

Incorporate latest electricity price forecasts, PtX revenue streams, and vendor pricing into project models. Note: Apart from the PtX revenues, this was progressed in the later Worley techno-economic work. Refer section 12.

Assess alternative configurations (e.g., single-site concept, different turbine technologies) and pipeline routing. Refer section 12.

Advance Water Reuse: Explore local reuse of effluent to eliminate the need for a return pipeline. Consider other water sources.

Perform detailed QRA, dynamic pipeline modelling, and further safety studies in the next project phase.

Maintain proactive engagement with regulators, landowners, and the community to secure approvals and social license

## 9.5 Lessons Learnt

**Flexibility is Critical:** Designing for multiple commercial pathways (arbitrage, PtX) increases project resilience to market changes.

**Technology Maturity:** Rapid advances in electrolyser and turbine technology require ongoing market monitoring and flexibility in procurement.

**Cost Sensitivities:** Early, detailed cost breakdowns and sensitivity analyses are essential for informed decision-making and risk mitigation.

**Community and Environmental Considerations:** Early identification and management of community impacts (noise, light, land use) are vital for project success.

# 10. SOCIAL LICENSE, STAKEHOLDER AND REGULATORY

## 10.1 Summary - Context, scope, methods

Building and maintaining social license is central to the project's feasibility and future development, with early engagement focused on transparent communication, education, and collaboration with local communities, regulatory bodies, First Nations (Eastern Maar), landowners, and other stakeholders. The scope encompasses a phased approach: an 18-month feasibility study, a potential Demonstration Pilot, and eventual potential commercial operations, each requiring tailored stakeholder consultation and regulatory compliance. Engagement methods included interviews, briefings, workshops, surveys, and ongoing updates via digital and in-person channels, guided by best practice frameworks such as IAP2 and Victorian Government standards. Regulatory pathways are being actively developed in partnership with government authorities, notably seeking amendments to the Petroleum Act 1998 (Vic) to provide a framework for UHS in Victoria and alignment with environmental, planning, safety, and cultural heritage legislation. The project's approach ensures stakeholder feedback informs design, risk management, and community benefit planning, while regulatory compliance is systematically mapped and pursued to enable responsible, sustainable hydrogen storage development.

## 10.2 Results and Conclusions

The results and conclusions across the H2RESTORE Stakeholder Engagement Report, Stakeholder Engagement Plan, and Regulatory Approval Plan collectively demonstrate that the project has established a strong foundation for social license and stakeholder trust during its feasibility phase. Stakeholder engagement activities—including interviews, surveys, workshops, and ongoing communications—revealed broad support among engaged groups for renewable hydrogen production and underground storage, with safety, economic opportunity, energy cost reduction, energy security, and environmental protection consistently identified as top priorities.

The reports also highlight knowledge gaps in the broader community regarding hydrogen technology and note consultation fatigue in regions with multiple energy projects, leading to a preference for engagement when more concrete project details are available. Transparent, accessible communication and proactive engagement, especially with First Nations stakeholders, were found to be essential for building trust and ensuring that feedback informs project design and risk management. The engagement process was iterative and multi-channel, targeting both directly impacted stakeholders and the wider community, with lessons learned emphasising the

importance of clarity, responsiveness, and inclusivity. On the regulatory front, the project team identified a complex and evolving landscape, with key legislative gaps—particularly around underground hydrogen storage—requiring ongoing collaboration with government authorities to amend existing legislation and align with environmental, planning, safety, and cultural heritage requirements. Systematic mapping of required approvals and early engagement with regulators have positioned the project to navigate these challenges effectively. Overall, the reports conclude that the feasibility phase has successfully laid the groundwork for future pilot and commercial phases, with stakeholder feedback and regulatory compliance remaining central to responsible, sustainable project development as H2RESTORE progresses.

## 10.3 Insights

**Stakeholder Support and Priorities:** There is strong support among engaged stakeholders—including government departments, industry, First Nations, and community representatives—for renewable hydrogen production and underground hydrogen storage. Safety, economic opportunity, energy cost reduction, energy security, and environmental protection were consistently identified as top priorities.

**Knowledge Gaps and Engagement Fatigue:** While interest in hydrogen technology is high, general understanding remains low, especially regarding underground storage and its benefits for grid stability. Consultation fatigue was noted in regions with multiple energy projects, leading to a preference for engagement when more concrete project details are available.

**Importance of Transparent Communication:** Stakeholders emphasised the need for clear, ongoing updates, tailored to local concerns and delivered through preferred channels (mainly email, website, and in-person events).

**Community Benefits Must Be Meaningful:** Stakeholders and the community are interested in understanding how the project will bring benefits locally, beyond one-off community grants or funds.

**Regulatory Complexity:** The regulatory landscape for underground hydrogen storage is evolving, with key legislative gaps—particularly the lack of framework for underground hydrogen storage in Victoria—requiring ongoing collaboration with authorities.

## 10.4 Recommendations

**Build Social License Through Early and Ongoing Engagement:** Proactively engage stakeholders, especially those directly impacted, to build trust and ensure their feedback informs project planning and risk management.

**Tailor Communication and Education:** Use simple, accessible language and multiple channels to address knowledge gaps and prevent misunderstandings. Avoid technical jargon and focus on what the average community member needs to know.

**Iterative Engagement Approach:** Update engagement plans and methods as the project progresses, reflecting changing circumstances, feedback, and lessons learnt.

**Collaborate Closely with Regulators:** Work with government authorities to address legislative gaps, particularly around underground hydrogen storage, and ensure compliance with environmental, planning, safety, and cultural heritage requirements.

**Prioritise Community Benefit Planning:** Develop innovative, long-term community benefit programs that go beyond one-off grants, ensuring local economic and social value.

### 10.5 Lessons Learnt

**Early Engagement is Vital:** Building trust and social license requires early, transparent engagement, especially with First Nations stakeholders and those most impacted.

**Balance Transparency and Certainty:** Some stakeholders prefer updates only when more information is known about project scale, location, and timing. It's important to balance early engagement with sharing useful and definite information.

**Stakeholder Feedback Drives Project Evolution:** Ongoing, transparent engagement ensures that community and stakeholder priorities are reflected in project planning and risk management.

Preferred Communication Channels: Email updates were the preferred method for stakeholders to be kept informed about the project.

## 11. OPERATIONAL PROFILES AND ASSUMPTIONS

The H2RESTORE Project is designed around two principal operational profiles: Power-to-Gas-to-Power (P2G2P) and Power-to-X (P2X). Each profile is tailored to address distinct commercial and technical objectives, leveraging underground hydrogen storage (UHS) to maximise value from both energy arbitrage and firm hydrogen supply.

**Power-to-Gas-to-Power (P2G2P) Profile**

In the P2G2P operational mode, the facility operates as a long-duration energy storage system, enabling the temporal shifting of electricity via hydrogen as an energy vector. During periods characterised by low electricity prices—typically coinciding with high renewable generation and low system demand—electrolysers are operated at full capacity to produce hydrogen. This hydrogen is then injected and stored in a depleted gas reservoir, which serves as the UHS site.

When electricity prices rise, often during periods of peak demand or low renewable output, the stored hydrogen is withdrawn from the reservoir and utilised as fuel in open cycle gas turbines (OCGTs). These turbines, which may be of the aeroderivative or frame type, are selected for their rapid start-up capabilities and suitability for intermittent operation. The generated electricity is exported back to the grid, capturing value from the differential between low and high price periods.

The facility is designed to operate in discrete modes: hydrogen production and injection, hydrogen withdrawal and power generation, or standby. Equipment is operated at either 0% or 100% of nameplate capacity, with no provision for partial load operation. This approach simplifies operational control and aligns with the economic drivers of maximising arbitrage opportunities. The P2G2P profile is thus fundamentally dependent on the volatility and spread

of electricity market prices, as well as the technical performance of the storage and generation assets.

To assess the targeted underground hydrogen storage reservoir, the reservoir simulation modelling used an operational profile consistent with the above and with the following assumptions. During production, instead of maintaining a constant rate, production was set to 32 episodes of 6-hour production intervals followed by 3.75 days of shut-in (4 days in total), resulting in 128 days of active production. This allows 235 days available for injection, with a one-day transition period between injection and production phases. The injection rate is assumed to be uniform over time, subject to operational constraints. For withdrawal, the target rate is based on energy output, as it is anticipated that hydrogen will be co-produced with residual natural gas. The target energy rate for each production episode is set at 1,268 MW. This is estimated to be sufficient to operate a turbine producing 500 MW of electrical energy at approximately 40% efficiency. With the lower heating values (LHV) of 10.2 MJ/Sm³ for hydrogen and 36 MJ/Sm³ for methane (the energy output from other components is considered negligible), the wells are controlled to meet an energy output target of 0.88 PJ per production cycle.

**Power-to-X (P2X) Profile**

The P2X operational profile focuses on providing a continuous and reliable stream of high-purity hydrogen to industrial users for producing derivatives like ammonia or methanol. This requires the facility to ensure a consistent and high-quality hydrogen supply, typically delivered through a dedicated pipeline to the user's site

To meet the stringent purity and delivery requirements of P2X customers, hydrogen may be supplied directly from the electrolysers during periods of production or withdrawn from underground storage when production is curtailed. The system incorporates additional purification steps, including demethanation and dehydration, to ensure that the hydrogen meets or exceeds the required specifications that would be determined based on customer requirements. The requirements for purification would be revisited in the future based on a specific customer.

The P2X profile necessitates a steady-state operational philosophy, with hydrogen production and withdrawal balanced to maintain continuous supply. The design accommodates both the variability of renewable electricity supply and the operational constraints of the storage reservoir. The pipeline infrastructure is engineered for continuous operation, and the facility's control systems are configured to switch seamlessly between production and withdrawal modes as dictated by market conditions and user demand.

In summary, the H2RESTORE Project's operational profiles are structured to provide both flexible, market-responsive energy storage and reliable, high-quality hydrogen supply. The facility's design and operational strategies are underpinned by robust technical and economic assumptions, ensuring adaptability to evolving market conditions and customer requirements.

**Table 8: Key Operational Parameters and Assumptions**

| Parameter | Value/Assumption | Notes |
|---|---|---|

| | | |
|---|---|---|
| Electrolyser Technology | PEM (base), AWE (sensitivity) | Ongoing vendor engagement and technology monitoring |
| Electrolyser Capacity | 200 MW, 500 MW | Higher utilisation of smaller unit favoured |
| Hydrogen Storage | 6,400–6,700 t $H_2$, 118–140 barg | Reservoir "A" |
| Power Generation | 500 MW OCGT (aeroderivative/frame) | Initial assessment -10 x GE LM6000 (aero) final techno-economics suggest frame units |
| Pipeline (HPF-HSS) | 71 km, DN450, 80 barg MAOP | Bi-directional, cyclic operation. Single site option eliminates this operational pipeline |
| Pipeline (HPF-PtX) | 82 km, DN150, 30–80 barg | Continuous supply to offtaker. Location unknown at this time |
| Water Source | Warrnambool STP, recycled and demineralised | 2-stage treatment, 45 km pipeline. Potential for deep aquifer sourced at consolidated HPF-HSS-HPG |
| Operating Modes | 0% or 100% load (no partial operation) | For both production and generation |
| Project Life | 25 Years | |
| Safety | Standard engineering controls, QRA recommended | HAZID completed, further QRA in next phase |

# 12. PROJECT ECONOMICS

## 12.1 Overview

Worley Consulting undertook techno-economic analysis for H2RESTORE at the beginning of the feasibility study and refined the analysis later in the study using findings and insights gained throughout the study.

H2RESTORE project economics considered two general configurations:

A Power to Gas to Power (P2G2P) model, leveraging UHS to store hydrogen produced by electrolysis during low electricity price periods and generate electricity during high price periods using gas-fuelled turbines, and

A Power to X (P2X) model, providing a firmed hydrogen offtake, producing hydrogen during low and moderate electricity price periods and storing a portion of this hydrogen to supply in times of high electricity price periods.

For the P2P2G configuration, where electricity price forecasts present a significant arbitrage opportunity, and plausible but somewhat favourable input assumptions are included in modelling, the project can achieve a commercial nominal internal rate of return (IRR). The preferred configuration includes a 200 MW electrolyser, a 500 MW hydrogen-fuelled gas turbine, and matched to 6,400 tonnes of underground hydrogen storage. The P2G2P configuration provides long-duration energy storage (LDES) capability, crucial for grid firming as renewable penetration increases.

For the P2X concept, UHS also offers the potential to reduce the Levelised Cost of Hydrogen (LCOH) for large P2X hydrogen offtakers producing derivatives like ammonia and methanol by providing a consistent hydrogen supply through buffering. Modelling shows that a 500 MW electrolyser coupled with 6,400 tonnes of UHS achieves the lowest LCOH, around $7 per kilogram of hydrogen.

The project's economic modelling is highly dependent on future electricity market conditions, with variability in forecasts affecting returns. It is recognised that the potential for actual future electricity prices to vary from long-term forecasts is significant.

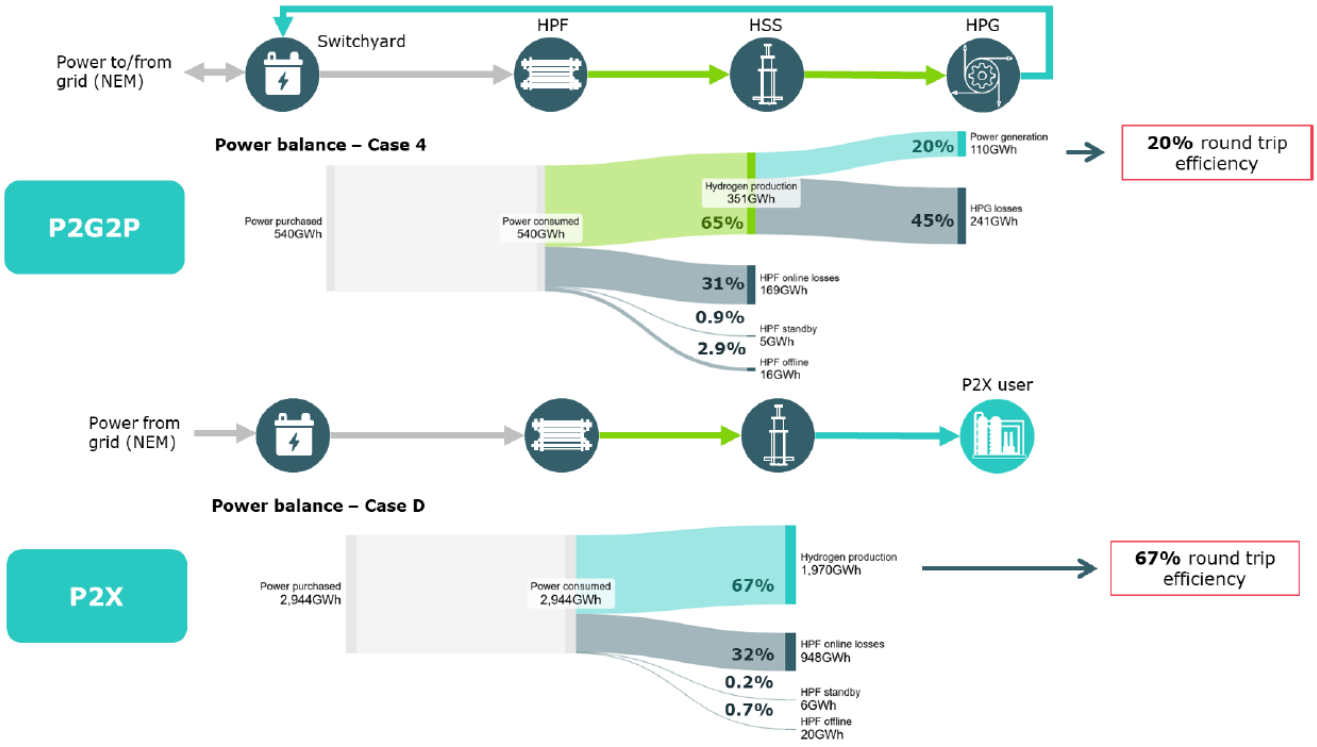



**Figure 11. Efficiency loss at each processing step for Power to Power and Power to X scenarios**

## 12.2 Technical and Economic Assessment

### 12.2.1 Project Configuration and Cost Optimisation

A trade-off study determined that consolidating the Hydrogen Production Facility (HPF) and Hydrogen Storage Site (HSS) into a single site at the McIntee reservoir could yield over AUD 150 million in capital expenditure (CAPEX) savings by eliminating hydrogen and water transmission pipelines, despite higher electrical system costs. A single-site configuration is the currently the preferred option from a cost point of view.

Multiple project cases with varying HPF and Hydrogen Powered Generator (HPG) capacities, load factors, and turbine technologies were analysed. The best economic performance was observed with a 200 MW electrolyser operating at a 37% load factor, a 500 MW frame-type hydrogen turbine at 2.5% load factor, and 6,400 tonnes of storage. Higher HPG load factors increase utilisation but can reduce returns due to less favourable average electricity price. Combined cycle gas turbines (CCGT) showed worse economics compared to frame open cycle gas turbines (OCGT) due to higher CAPEX outweighing efficiency gains considering the low-capacity factors applied.

### 12.2.2 Electricity Price Forecasts and Market Impact

Long-term electricity market spot price forecasts from two separate providers received over the past two years show substantial differences, especially in the number of zero or low-price hours and the distribution of high-price periods. Longer durations of near-zero prices is more favourable for electrolyser operation and project economics. Price forecast uncertainty a significant commercial challenge for the project.

### 12.2.3 Sensitivities and Financial Variables – P2G2P

Sensitivity analysis highlighted key variables affecting project viability:

- Waiving network charges, which constitute nearly 45% of electricity costs (noting assumptions in spot prices), would significantly improve economics.
- Model tuning (varying operations based on real-time conditions) to optimise storage utilisation and system dynamics can improve IRR by around 1.5%.
- Electrolyser CAPEX reductions and efficiency improvements, while beneficial, have modest impacts.
- Delays in generator or electrolyser response times reduce revenues moderately.
- Start-up fuel consumption for turbines has minimal economic impact, noting this would increase in significance with more frequent start/stop.

### 12.2.4 Additional Revenue and Support Mechanisms – P2P2G

The Australian Government's Hydrogen Production Tax Incentive (HPTI), offering $2/kg hydrogen for production between 2027 and 2040, would provide a modest revenue boost, improving IRR by about 0.5%. Capacity payments, similar to those in Western Australia's

Electricity Market (WEM), could materially enhance project returns. Government CAPEX subsidies of around 25% (approximately $400 million) would be beneficial to project economics.

Further support mechanisms could include:

- Prioritised and/or higher levels of support for concepts that present multi-sectoral application/benefits. H2RESTORE can underpin a hub including hydrogen battery, localised hydrogen derivative production, and firm hydrogen offtakes.
- Prioritised and/or higher proportion of support and seed funding to take projects up the technology readiness ladder.
- Prioritised and/or higher levels of support for projects that have a clear pathway to supporting/enabling Australia's aspirations of being a renewable energy leader internationally, including and especially those that assist renewable energy exports, such as H2RESTORE.
- Government to underwrite a share of the project risks to enable lower costs of equity and higher debt.
- State-owned NEM participants to prioritise contracting services for low emissions long-duration dispatchable storage.
- Recognise that H2RESTORE could provide energy security benefits and provide financial support accordingly (local energy supply to produce renewable fuel locally).
- Recognise a project of H2RESTORE's scale can act as a platform for Australia to become a world leader in an innovative technology(ies) and provide financial support accordingly.
- Network tariff structures which reward the project for using networks for import when demand is lower than available renewable supply.
- Reliability standards to reference *higher* possibility of *longer* low-VRE periods, which would show necessity of greater capacity and depth of long duration storage.
- Existing markets incentivised, or new markets created, to value the characteristics H2RESTORE offers including greater value for renewable dispatchable energy (when validated using Renewable Energy Guarantee of Origin Certificates) and greater value for longer duration energy storage and dispatchability (vs shorter duration).

## 12.3 Power to X (P2X) Hydrogen Offtake Analysis

The use of UHS to buffer hydrogen supply reduces LCOH compared to continuous production or short-term storage, especially at larger electrolyser capacities (e.g. 500 MW). Non-UHS storage requires higher electrolyser load factors and smaller capacity, resulting in higher costs. UHS enables inter-seasonal energy transfer and operational flexibility, making it competitive for large-scale hydrogen derivative production.

### 12.4 Technical and Regulatory Considerations

Hydrogen injection rates into storage reservoirs may limit the maximum electrolyser capacity, potentially requiring additional fields to be developed. Technology advancements, such as second-generation pressurised alkaline electrolysers, or AEM electrolysers, may present future CAPEX reductions and efficiency improvements. Regulatory developments, including potential capacity markets and network charge waivers, would support project viability, as would supportive government policies and underwriting of market risks.

### 12.5 Summary of Insights and Recommendations

Key insights include:

- Electricity cost and sale prices drives project economics significantly.
- Single-site configuration provides substantial CAPEX savings.
- CAPEX is a major cost driver due to low load factors.
- Electrolyser cost reductions and efficiency gains have minor impacts compared to market variables.
- Network charges are material to returns.
- Capacity payments and government subsidies can help support a business case.
- Injection rate constraints can limit maximum electrolyser capacity due to UHS operational factors for a single field development.
- Market uncertainties are key challenges to address.

UHS has the potential to be a competitive long-duration energy storage solution and a cost-effective hydrogen supply method for P2X applications, contingent on electricity market conditions and supportive regulatory and financial frameworks.

## 13. EXTERNAL BENEFITS FOR THE NEM

### 13.1 Overview

Frontier Economics has provided their report titled "The Value of Hydrogen Storage" [35], which was produced using results generated by their *Energy42* integrated hydrogen-electricity sector long-term (2024/25 to 2049/50), nodal, least-cost optimisation model. *Energy42* simultaneously co-optimises investment and operation outcomes across hydrogen and electricity markets. The purpose of this work is to understand whether underground hydrogen storages have a role to play in a least-cost energy system, how they might function in that system, and how they can add value in the task of meeting future demand for hydrogen, and to a lesser extent, for electricity.

A base case scenario similar to the Integrated System Plan (ISP) Step-Change scenario for the NEM was produced showing electricity and hydrogen sector investment and market outcomes. An alternative case was then produced using the same model, allowing underground hydrogen

storage to be selected by the model if advantageous. This has demonstrated, even with only a moderate hydrogen sector as in the Step-Change scenario, underground hydrogen storage provides an overall lower-cost outcome and less reliance on gas for electricity generation.

The modelling consistently shows that underground hydrogen storage is the only form of hydrogen storage selected by the model when available. Pressure vessels and liquefied hydrogen are not chosen in material quantities, indicating that the full benefits of hydrogen storage for both hydrogen and electricity markets are only realised with underground options.

## 13.2 Benefits for the NEM

The Frontier Economics report shows the following benefits are made available to the NEM by UHS, assuming the ISP step-change scenario, which includes hydrogen demand.

- **Lower system costs**: The flexibility that could be provided by underground hydrogen storage enables the system to favour lower-cost renewable options (e.g. wind and solar). Underground hydrogen storage could enable hydrogen production during periods of high renewable electricity supply, reducing reliance on gas-fired generation to balance the grid in times of lower renewable electricity supply when there is still a demand for hydrogen supply.
- **Grid firming and reliability**: Hydrogen stored underground could be used to generate electricity during periods of low renewable output, contributing to long-duration, inter-seasonal energy storage.
- **Reduced renewable curtailment**: Storage would allow electrolysers to operate flexibly, reducing curtailment of renewable energy and improving utilisation of wind and solar assets.
- **Minimal impact on transmission infrastructure**: Despite enabling significant flexibility, underground hydrogen storage has only a small impact on the need for additional transmission pipelines, making it a cost-effective solution.
- **Strategic fit with NEM planning**: Underground hydrogen storage can support renewable dispatchable generation, help maintain affordable and reliable energy, and enable flexibility in adapting to emerging technologies.
- **Resilience even without seasonal demand**: Even in scenarios with flat hydrogen demand, underground hydrogen storage still delivers value by enabling seasonal production shifts aligned with renewable generation patterns.

## 13.3 Summary of Insights

1. Underground hydrogen storage is an important part of a least cost hydrogen supply chain.

   When underground hydrogen storage is an option for the model to include as part of a least cost system – we see that the model chooses to invest in significant amounts of underground hydrogen storage because it is part of the least cost system.

2. Underground hydrogen storage reduces the need for ‘firmed’ electricity generation.

Having underground hydrogen storage enables electrolysers to operate much more flexibly while still meeting the same hydrogen offtake demand.

3. Underground hydrogen storage changes the mix of renewable generation towards lower-cost options.

   Underground hydrogen storage shifts the renewable energy mix towards lower-cost options, particularly solar generation. The seasonal storage capability of underground hydrogen storage supports the integration of more solar energy, which has a lower levelised cost of energy than wind generation.

4. Underground hydrogen storage enables lower cost hydrogen production.

   By allowing electrolysers to operate flexibly, it reduces the average electricity prices for hydrogen production, leading to lower hydrogen prices over time.

5. Other forms of hydrogen storage are not a good substitute for underground hydrogen storage.

   When all forms of hydrogen storage are available, the model opts to invest in, and make use of, a significant amount of underground hydrogen storage. Where underground hydrogen storage is not available but liquified hydrogen storage and pressure vessels are available, the model does not choose to invest in any material amounts of these other forms of hydrogen storage. This suggests that the benefits for the hydrogen market and electricity market that hydrogen storage can provide are not achieved if underground hydrogen storage is not available.

6. There is benefit to underground hydrogen storage even without seasonal differences in demand.

   In the modelling, underground hydrogen storage is being used to enable seasonal increases in hydrogen production, while assuming a reasonably flat annual demand profile. Scenarios with seasonal demand (higher in winter, lower in summer) would likely see increased investment in underground hydrogen storage to meet these variations.

7. Enabling underground hydrogen storage only has a small impact on the required amount of transmission pipeline infrastructure.

   Base Case and Hydrogen Storage Scenario: hydrogen transmission pipelines are a critical part of the hydrogen supply chain. This is because the modelling finds it is generally cheapest to produce hydrogen adjacent to sources of renewable generation (in REZs) and to transport the hydrogen to customers for use. The availability of underground hydrogen storage does not have a large impact on the transmission pipeline network required for the hydrogen sector.

## 14. MACROECONOMIC BENEFITS OF LARGE SCALE UHS AND BROADER ECONOMIC CONSIDERATIONS

The development of large-scale underground hydrogen storage (UHS) systems could offer significant macroeconomic benefits. These benefits are multifaceted and include:

1. **Lower cost hydrogen production**: Electrolysers can operate during periods of low electricity prices, improving their utilisation and reducing the average cost of hydrogen production.

2. **Infrastructure Synergies**: The integration of UHS with existing energy infrastructure, such as high-voltage transmission lines, enhances the efficiency and effectiveness of the energy system. This synergy reduces the need for additional infrastructure investments and optimises the use of existing assets.

3. **Hydrogen sector jobs and investment**: The hydrogen sector, enabled by underground storage, is projected to deliver significant job creation, increased investment in regional hydrogen hubs, and competitive hydrogen pricing [35].

4. **Industrial decarbonisation**: Underground hydrogen storage supports reliable supply for clean fuel industries and decarbonisation of hard-to-abate sectors.

5. **Export readiness:** While export demand is modest in the ISP Step Change scenario, underground hydrogen storage positions Australia to scale up exports if demand increases.

## 15. CONCLUSIONS AND DISCUSSION BASED ON FINDINGS

The H2RESTORE Feasibility Study has been comprehensive, well executed and achieved the objectives for the study.

- UHS in the depleted gas reservoirs of the onshore Otway Basin is technically feasible.
- Early stakeholder engagement has made progress in building social engagement and support.
- The combination of concept select studies and techno-economic analysis has found that the business case is highly sensitive to future electricity market conditions, particularly the frequency and magnitude of price swings.
- Under favourable electricity price forecasts and with supportive mechanisms such as capacity payments and network charge waivers, the project is expected to achieve a commercial real internal rate of return.
- The most commercial configuration identified combines 200 MW of hydrogen production with 500 MW of hydrogen-fuelled generation and >6,000 tonnes of underground hydrogen storage, with potential for further improvement by increasing storage capacity.
- Economic studies have identified that UHS has the potential to reduce the cost of hydrogen by using the storage to produce hydrogen during times of low electricity price.
- A depleted gas field and reservoir have been identified for a potential UHS Demonstration Pilot with the Feasibility Study work across reservoir, surface facilities, landholder, and regulatory advanced sufficiently to technically support progression to Front End Engineering Design.

The H2RESTORE Feasibility Study demonstrates that large-scale UHS in depleted gas reservoirs is technically feasible and potentially commercially viable and could play a pivotal role in supporting Australia's energy transition. By leveraging low-cost renewable electricity for hydrogen production and providing long-duration energy reserves, the project offers a pathway to grid stability, decarbonisation of the of the NEM and hard-to-abate sectors, and a reliable supply for emerging clean fuels industries. The Feasibility Study confirms that the selected

onshore Otway Basin reservoir - the Waarre C formation - possesses the necessary integrity, containment, and operational characteristics to support safe and effective hydrogen storage at both pilot and commercial scales.

Comprehensive geomechanical and geochemical analyses have shown that cyclic hydrogen injection and withdrawal do not compromise reservoir or caprock integrity, with only minor, manageable changes observed in rock and cement properties. Laboratory and modelling work further confirm that hydrogen has minimal interaction with reservoir minerals and fluids, and that wellbore cement remains stable under representative conditions. Microbial studies highlight the complexity of subsurface sampling and the need for improved protocols, but do not identify any immediate barriers to deployment. The reservoir modelling workstreams have validated both the minimum viable pilot volume and the commercial-scale working storage capacity, demonstrating the ability to deliver up to 500 MW of dispatchable power and approximately 96 GWh of long-duration energy storage.

From a commercial perspective, concept select studies and techno-economic modelling indicate that project economics are strongly influenced by the sizing and utilisation of electrolysis and power generation facilities. The optimal configuration identified is a 200 MW electrolyser operating at a high-capacity factor, paired with 500 MW of hydrogen-fuelled generation at a lower load factor. Capital expenditure is dominated by hydrogen production and power generation, while underground storage and other costs are comparatively modest. The business case is highly sensitive to future electricity market conditions, network charges, and policy incentives, with additional revenue streams such as capacity payments and tax incentives essential to bridge the commercial gap. Consolidating hydrogen production, storage, and generation at a single site offers significant cost savings and operational efficiencies.

The project has made substantial progress in building social licence, with targeted engagement of key stakeholders—including local councils, First Nations representatives, landowners, and regulatory bodies—yielding support for renewable hydrogen production and underground storage. Stakeholder surveys and engagement activities have identified safety, economic opportunity, energy security, and environmental protection as top priorities, while also highlighting the need for clear communication and tailored community benefits. The regulatory approvals pathway remains a key challenge, with legislative amendments required to authorise UHS in Victoria, and ongoing engagement with policymakers is positioning the project for future success.

In terms of broader impact, the H2RESTORE Project has advanced technical skills, modelling capabilities, and risk management practices relevant to renewable energy technologies. The methodologies and lessons learned are transferable to other depleted gas fields, both within Australia and internationally. Macroeconomic analysis confirms that UHS can deliver lower system costs, reduce reliance on gas-fired generation, and support the development of competitive hydrogen markets, with significant potential for job creation and investment.

In summary, the H2RESTORE Feasibility Study has validated the technical and commercial foundations for underground hydrogen storage in the Otway Basin, identified key operational and economic drivers, and established a robust framework for stakeholder engagement and regulatory compliance. The project is well positioned to proceed to pilot and commercial phases, subject to Lochard Board and investor approvals, commercial arrangements, regulatory approvals, continued optimisation, supportive policy, and market reforms. Ongoing innovation,

adaptive engagement, and regulatory advancement will be essential to realise the full potential of UHS as a cornerstone of Australia's cleaner energy future.

# 16. APPLICABILITY AND TRANSFERABILITY TO OTHER SITES

## 16.1 Feasibility Study Outcomes

### Technical Feasibility

The project's findings on the technical feasibility of storing hydrogen in depleted gas reservoirs can be applied to other similar geological formations. The studies conducted on reservoir integrity, geomechanical and geochemical analysis, and microbial interactions provide a comprehensive understanding of the conditions necessary for successful hydrogen storage. More detailed information is provided below at 16.2.

### Commercial Viability

The economic assessments and techno-economic modelling conducted as part of the study demonstrate the commercial viability of large-scale UHS. These findings can be used to inform similar projects in other regions, particularly those with access to low-cost renewable electricity and existing gas infrastructure.

The Power to Gas to Power and Power to X concepts, combined with large scale Underground Hydrogen Storage (UHS) provides an approach to utilising the renewable electricity generation capacity that is curtailed during times of high and surplus renewable generation when demand is low. Simultaneously, this approach produces hydrogen, which can be used for long-duration energy storage, grid firming, and/or supplying emerging clean fuel industries.

### Regulatory Pathways

The development of a Regulatory Approvals Plan and engagement with key stakeholders, including regulatory bodies, First Nations, landowners, and environmental groups, provides a framework that can be adapted for other UHS projects. The identification of regulatory gaps and the need for legislative amendments highlight the importance of early and ongoing engagement with policymakers.

### Community Engagement

The project's approach to community and stakeholder engagement, including the development of a Stakeholder Engagement Plan and conducting surveys to gauge community sentiment, can be replicated in other regions. The emphasis on clear communication, addressing community concerns, and tailoring local benefits to their needs is crucial for gaining social license for UHS projects.

### Knowledge Sharing

The comprehensive documentation of the project's findings, including presentations at conferences and seminars, technical reports, stakeholder engagement outcomes, and economic assessments, provide valuable insights that can be shared with other UHS projects. This knowledge sharing can help accelerate the development of UHS technology and its adoption in different regions.

### Technology Readiness Level (TRL)

A comparison to the IEA Hydrogen TCP-Task 42 Final Report [36] and the Underground Hydrogen Storage Technology Monitoring Report [37] indicates the H2RESTORE Feasibility Study has not only kept pace but in several areas surpassed the IEA TASK 42 guidance. This has been achieved by translating broad recommendations into site-specific, test-backed parameters and design decisions, including geochemical, microbial, geomechanical aspects, pilot mass thresholds, commercial site choice, integrity envelopes, and surface facility concepts based on detailed grid, water, and market testing via Expression of Interest packages.

For porous-media UHS, the Technology Readiness Level (TRL) was generally low (≈3–4) in 2023 [37], pending pilots and demonstrations to validate laboratory and modelling results in real reservoirs and to strengthen societal embeddedness.

H2RESTORE's evidence of laboratory validation (geochem/cement/microbial under representative HP/HT), integrated geomechanics, and history-matched dynamic modelling at pilot/commercial scales aligns with TRL-4/5 (component and system validation in lab/relevant simulated environments).

**H2RESTORE has progressed from ~TRL-3/4 to ~TRL-4/5 through Feasibility Study**. Pilot operations would move it to TRL-6, with full commercial ramp toward TRL-7/8 with multi-year cyclic operation and market integration.

## 16.2 Specific Aspects

### Microbial Aspects

The study highlights that obtaining representative, contamination-free samples of subsurface microbial communities is challenging. Even short-term deviations from in situ conditions (pressure, temperature, redox) can dramatically alter microbial composition, often leading to loss of native thermophilic taxa and overgrowth of contaminants.

Enhanced sampling protocols, including maintaining pressure and temperature, minimising contamination, and considering biofilm-associated communities, are essential for any UHS site. This is not unique to Otway Basin fields; similar issues will arise in other depleted reservoirs or subsurface environments.

1D microbial modelling capability to enable forward prediction of microbial reactions and their impacts on stored fluids over the life of a UHS operation. The work established a conceptual and methodological 1D modelling approach (using MOOSE) for predicting microbial reactions (methanogenesis, sulfate reduction) during UHS and is transferable to other sites, provided local microbial parameters are available.

The model demonstrates how microbial population density and water saturation affect hydrogen loss and byproduct generation—these relationships are relevant for any UHS site.

Why These Points Matter for Other Locations

- Sampling and contamination issues are universal in subsurface microbiology.

- Modelling microbial impacts on hydrogen storage is necessary everywhere but must be tailored to local conditions.
- Risks such as hydrogen loss and souring are common to all UHS sites.
- Geochemical controls on microbial activity vary by site, but the need to assess them is universal.
- Laboratory limitations mean field trials are always needed for validation.
- Recommendations for improved protocols and pilot studies are relevant for any future UHS development.

**Geomechanical**

1D and 3D Mechanical Earth Models (MEMs) were developed. Workflows started with 1D MEMs (well-based) and scaling up to a 3D MEM for field-scale analysis. This approach—using well logs, core data, and calibration with field observations—can be applied to any subsurface storage project to characterise mechanical properties, stress states, and validate models with drilling/wellbore stability data. The use of coupled simulations (e.g., one-way coupling between reservoir and geomechanical models) to assess stress/strain evolution during storage operations is a best practice for understanding subsurface responses to pressure changes, regardless of location.

The laboratory testing methodology for hydrogen exposure to reservoir rock samples with hydrogen under reservoir-like conditions and quantifying changes in elastic and strength properties (e.g., Young's modulus, UCS, friction angle) is directly transferable. The finding that hydrogen exposure can degrade geomechanical properties is a critical insight for any hydrogen storage project.

Utilising the geomechancial properties from hydrogen exposure experiments in the 3D MEM model is a first within Australia. The approach of applying property multipliers in the geomechanical model once a threshold hydrogen concentration is reached, and assuming these changes are permanent, is conservative and broadly applicable to future modelling strategies.

Assessing cap rock integrity based on accumulated plastic strain and tensile failure criteria is a generalisable method. The use of plastic strain thresholds to evaluate breach risk can be applied to other sites with different lithologies.

The use of fault plastic shear strain to screen for instability risk is a robust, transferable approach. The recommendation to manage fault instability risk by maintaining reservoir pressures above historical minimums is a practical operational guideline.

Quantifying vertical displacement at both the reservoir and surface (subsidence/heave) provides a template for monitoring and managing geomechanical impacts in any storage project and assist public messaging concerning surface impacts.

The observation that microseismic techniques for fault movement monitoring is broadly applicable to any site where fault reactivation is a concern. Noting, the requirement for microseismic monitoring should be assessed in a targeted risk-based manner.

The operational recommendation to avoid drawdown below historical minimum pressures to mitigate fault instability risk and to minimise porosity and permeability degradation is also a transferable lesson.

**Reservoir**

The H2RESTORE Feasibility Study has focused on underground hydrogen storage (UHS) in onshore depleted gas fields in the Otway Basin, Victoria. The findings suggest that other onshore depleted gas fields in Australia, such as those in South Australia, Western Australia, and Queensland, could also be suitable for UHS. Offshore depleted gas fields could be used as well, though they would likely be more expensive due to additional costs for wells, platforms, and pipelines.

The methodology for screening candidate depleted gas fields for UHS, including preliminary estimation of storage volumes based on static models, has been reviewed and discussed [11]. The subsequent dynamic modelling has demonstrated that these preliminary estimates are a reasonable guide, making this approach applicable to other onshore depleted gas fields in Australia and elsewhere. The final dynamic modelling results for working storage volume (WSV) as a proportion of total stored hydrogen should also be useful for site screening of similar reservoirs.

The screening process highlighted the differing requirements of pilot-scale and commercial-scale projects, which has more general applicability. For pilot-scale UHS, a small and steeply dipping structure is preferred to minimise the amount of hydrogen required. For commercial scale, a large and shallow dipping structure is preferred to improve project economics. The presence of aquifer pressure support is also a key feature, enabling the progressive use of larger depleted fields while maintaining deliverability for fast withdrawal. This style of gas reservoir is relatively common in Australia. By contrast, depletion-drive reservoirs (without aquifer pressure support) may require larger injection volumes to fill the reservoir and increase the pressure. These reservoirs can have compensating advantages, such as higher recovery overall and less gas mixing [38].

One potential drawback of UHS in depleted gas fields is the mixing of stored hydrogen with the remaining native gas in the reservoir. If high purity is desirable for the hydrogen on withdrawal, either the working storage volume must be smaller (keeping more hydrogen as cushion gas) or the withdrawn gas needs to be purified, with additional costs. The H2RESTORE project has focused on a use case where the withdrawn hydrogen is fed into a turbine to generate electricity, which allows for a wide range of mixtures between hydrogen and natural gas, eliminating the need for a gas purification step. For this use, depleted gas fields are highly suitable for UHS. However, if high purity hydrogen is required for other applications, such as producing hydrogen carriers like ammonia, depleted gas fields may be less suitable.

The reservoir modelling process for UHS used in this project builds upon standard approaches used in petroleum development, carbon capture and storage, and underground gas storage projects. This approach should be applicable to pilot developments in other depleted gas fields.

Overall, the subsurface reservoir modelling for H2RESTORE Feasibility Study has set out a high-quality framework for assessing UHS in other depleted gas fields. Many of the issues found in this project will be relevant to other such developments in Australia or internationally.

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