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Prospectivity analysis for underground hydrogen storage, Taranaki basin, Aotearoa New Zealand: A multi-criteria decision-making approach

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ABSTRACT

Seasonal underground hydrogen storage (UHS) in porous media provides an as yet untested method for storing surplus renewable energy and balancing our energy demands. This study investigates the technical suitability for UHS in depleted hydrocarbon fields and one deep aquifer site in Taranaki Basin, Aotearoa New Zealand. Prospective sites are assessed using a decision tree approach, providing a "fast-track" method for identifying potential sites, and a decision matrix approach for ranking optimal sites. Based on expert elicitation, the most important factors to consider are storage capacity, reservoir depth, and parameters that affect hydrogen injectivity/withdrawal and containment. Results from both approaches suggest that Paleogene reservoirs from gas (or gas cap) fields provide the best option for demonstrating UHS in Aotearoa New Zealand, and that the country's projected 2050 hydrogen storage demand could be exceeded by developing one or two high ranking sites. Lower priority is assigned to heterolithic and typically finer grained, labile and, clay-rich Miocene oil reservoirs, and to deep aquifers that have no proven hydrocarbon containment.

1. Introduction

Energy production using hydrogen gas (H_2) for combustion and electrochemical fuel cells emits no greenhouse gases and, as such, is expected to play an important role in a future global carbon-neutral economy [1–4]. While hydrogen can be produced by different industrial processes, it is water electrolysis that produces "green hydrogen" by using renewable electricity [5–7]. The temporary storage of excess renewable energy, as green hydrogen, has been proposed to mitigate the fluctuating supply of electricity from renewable sources, while balancing energy supply and demand [2,8–12]. Wind and solar power are two renewable sources set to provide significant energy in the future, yet their output is heavily dependent on short-term climatic fluctuations. Consequently, underground hydrogen storage (UHS) is considered an attractive large-scale energy storage option for renewable spill [2,3,5,7,12].

The concept of UHS is to convert surplus green electricity into H_2 and inject it underground into porous geological formations (such as depleted hydrocarbon reservoirs or deep aquifers) or salt caverns/engineered cavities. Caverns and cavities may provide a relatively small, peak load storage solution (e.g., 10s–250 GWh range [7,13]), while UHS in geological formations can provide sufficient volume to fulfil seasonal storage requirements (e.g., TWh range [14–16]). To maximise the yield of renewable energy systems, H_2 would be stored during periods of high surplus and low energy demand, and then be extracted as dictated by increasing demand, thus supporting management of the energy system.

UHS in porous formations requires a suitable geological structure in the form of a trap (structural, stratigraphic or combination), a porous and permeable reservoir to store H_2, and an impermeable caprock (top seal) to prevent upwards leakage. In addition, UHS requires a cushion gas, which would be stored below the working gas, primarily to maintain the required operating pressure and deliverability rate [9,11,17,18]

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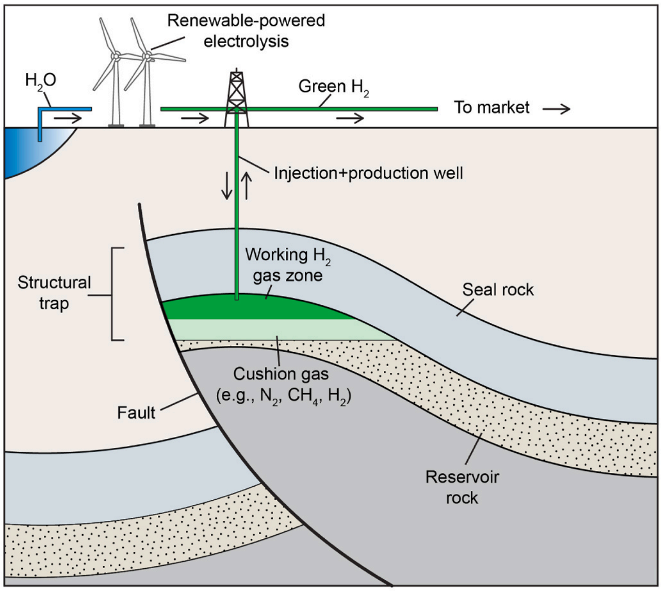


Fig. 1. Simplified UHS scenario. H_2 is injected and stored as the working gas zone in a permeable reservoir, trapped in a structural closure, and overlain by an impermeable seal (caprock). Injected H_2 will displace *in situ* pore fluid due to its lower density. The producible working gas zone is underlain by cushion gas, which will undergo alternate compression and expansion during injection and withdrawal cycles respectively to maintain pressure and deliverability.

(Fig. 1). The presence of a cushion gas may also help to prevent water from entering the storage compartment [9] and minimise H_2 losses [18]. Various gases can serve as the cushion gas, with a concentration gradient expected between H_2 and a denser gas (e.g., N_2 or CH_4), and the degree of mixing from advection, diffusion, buoyancy and other mobilization mechanisms dependent on cushion gas composition and site-specific storage operations (e.g., injection/withdrawal rate, reservoir properties etc.) [6,19].

The success of UHS will be dependent on locating suitable sites that satisfy a wide range of technical (geological) requirements, together with sociocultural, economic, political, and regulatory criteria [3,5,10,20,21]. To date, there are no operating industrial-scale UHS sites for high-purity H_2 in porous media, hence there are few established regulations and only a theoretical understanding of the social and economic impacts. Additionally, little is known about how H_2 will behave in the subsurface [22–24], and much more fundamental work on hydrogen systems is required to evaluate UHS feasibility [12,23].

The objective of our study is to undertake prospectivity analysis for UHS in Aotearoa New Zealand (A-NZ) as preparatory work to further UHS characterisation and research. First we introduce some previous work on underground gas storage (section 2), highlighting specific aspects and/or issues related to UHS in other parts of the world. The potential for UHS in Taranaki Basin (A-NZ) is then briefly described (section 3) and includes a summary of the A-NZ energy market and regional geology. This is followed by a description of methodologies (section 4) and results (section 5) for two different multi-criteria decision-making approaches to site evaluation. A comparison of the two approaches and summary of outcomes is presented in the discussion (sections 6.1 and 6.2 respectively). Our study provides an example for ranking UHS prospects based on current knowledge and using a comprehensive set of technical parameters. However, there remain some outstanding technical uncertainties with UHS technology, and further scientific research will be necessary to fully understand the requirements for successful deployment of UHS. Technical research directions for A-NZ that address some of the uncertainties are presented in the discussion section (section 6.3). Enviro-socio-cultural impacts unique to A-NZ are being investigated in parallel, and together will help generate a workflow for optimal UHS site selection that screens and ranks potential sites and provides an input to risk assessment.

2. Previous work

Many studies have been undertaken in recent years that discuss and characterise the potential for underground storage of gases in subsurface geological formations. The oil and gas industry has decades-long experience with underground natural gas storage (UGS) to buffer variable demands, many of which focus on depleted hydrocarbon reservoirs [3,4,21]. More recent work has explored long-term (permanent) underground storage of CO_2, which has the potential to play a significant role in the mitigation of global greenhouse gas emissions through carbon capture and storage (CCS). Both UGS and CCS studies include site screening, evaluation of storage capacity, best practices, monitoring, potential reactivity, and provide valuable insights for site evaluation in a general sense [25,26]. However, the storage of H_2 requires specific geological and operational conditions [9,23,27] and a more tailored approach must be developed for assessing UHS sites that consider the physico-chemical composition of H_2, and H_2 storage goals and processes.

The importance of hydrogen in the energy transition has gained significant attention in the last decade. UHS facilities have been developed in salt caverns to contain H_2 for industrial uses, and this technology is now well established [9,13,14,28]. However, experience with UHS in porous geological formations is limited to storage of gas mixtures (town gas) [6,11] and pilot projects in Argentina and Austria [11]. Preliminary UHS screening studies have been undertaken in several countries, including Australia [22], Brazil [29], Canada [28,30], China [31], Germany [32], Japan [33], Netherlands [34], Poland [20,35], Portugal [36], Spain [8], United Kingdom [4,9,37,38], and USA [14], and two larger projects (HyUSpre and Hystories) have recently completed an evaluation of storage capacities for porous reservoirs in multiple European countries [39–41]. The concept of UHS in Aotearoa New Zealand has also been considered, both from a geological perspective [24,42], and including cultural, environmental, commercial, and infrastructural aspects [42].

The feasibility of UHS in terms of hydrogen injection/withdrawal, transportation, storage, and economic viability has been the focus of several studies [8,14,43–46]. There are also a number of recent publications that provide comprehensive reviews on the technical requirements for UHS and/or potential issues that still need to be resolved [2,3,6,11,12,22,23]. These reviews have identified some key challenges for UHS as: the potential for H_2 leakage through faults and/or top seal; potential contamination and/or changes to rock properties related to geochemical reactions and microbial growth; operational issues, including the interaction of stored H_2 with residual fluids and/or cushion gas under reservoir conditions.

Recent investigations into H_2 flow dynamics and properties look at the behaviour of H_2 in response to its physico-chemical properties, such as high diffusivity, low viscosity, and high mobility [21–23]. These investigations comprise numerical simulations of UHS systems, looking at plume migration, injection/withdrawal cycles, recovery factors, and interphase interaction [18,19,39,40,47–53]. Input data for modelling rock/H_2/brine/petroleum systems is limited (e.g., wettability, interfacial tension, capillary pressure data) but has recently been gaining attention ([27,54], and references therein). These studies generally support the feasibility of UHS, and suggest minimal H_2 losses through caprocks of depleted gas reservoirs [52].

Significant work has also recently focused on the potential for chemical reactions [32,55–62] and microbial interactions [39,40,63,64] within UHS sites. While reactivity of silicates with H_2 is considered to be minimal over the timeframes for storage (months to years), there are several studies to suggest reactions are likely between H_2 and carbonates, sulphates and sulphides. These reactions could result in changes to petrophysical rock properties of reservoir or seal [32,57,65–69], and with the formation of methane and/or hydrogen sulphide contaminating the stored gas [6,40,55]. Microbial growth is expected to be significant for low-salinity, low-temperature reservoirs, which could significantly impact UHS through H_2 losses, clogging and corrosion [64].

At present there is very limited published work that focuses on selecting suitable sites for UHS [35,39–41,53,70,71]. Studies with weighted criteria suggest that of their assessed parameters, the most important are flow capacity and reservoir depth [71], overburden lithology [35], maximum well deliverability rate and cushion gas requirement [70], or readiness of the development (time-to-market) and risk induced by microbiological activity [40]. Research to date suggests that the success of UHS will be dependent on site-specific geological and operational conditions based on reliable site characterisation, and on identified technical parameter requirements specific to UHS. The reader is referred to supplementary data file 1, which summarises our current understanding of the main technical considerations for UHS based on many of the recent studies.

3. Potential for UHS, Taranaki basin, Aotearoa New Zealand

3.1. Aotearoa New Zealand energy market

A-NZ's energy market provides a small economy by global standards. Renewables, including hydro, geothermal and increasingly wind, dominate the electricity generation portfolio, with 87.1% of total generation from renewable sources in 2022 [72]. However, seasonal shortfall of electricity in A-NZ is currently accommodated by natural gas and/or coal, and other sectors are also largely reliant on hydrocarbons (e.g., industry, agriculture and transport) [72]. Data from the Ministry of Business, Innovation and Employment (MBIE) shows that total energy demand for 2022 was 150 TWh (543 PJ) of which 100 TWh (360 PJ) was sourced from hydrocarbons (oil, natural gas and coal). In a bid to decarbonise the economy the New Zealand Government has set a target of a 100% renewable electricity sector by 2030 and committed to achieving net-zero by 2050 [42,73]. Green hydrogen is being investigated as a replacement for hydrocarbons through its use in downstream industries (e.g., fertilizer production at Kapuni) and transport (e.g., Hiringa Energy hydrogen refuelling network) [24,42]. Hydrogen also has potential in A-NZ for export (e.g., methanol or urea), and for mitigating the fluctuating energy demand by low-carbon energy storage/withdrawal (e.g., UHS).

Yergin [74] suggested that hydrogen could account for at least 10% of the global energy system by 2050. For A-NZ, this would amount to ~15 TWh of hydrogen according to present energy demand, likely increasing by 2050. In A-NZ's North Island, there is a natural gas pipeline network and one underground storage facility, Ahuroa, with capacity for about 10% of annual gas use. The network owner, FirstGas Group, have proposed that hydrogen could replace natural gas in most sectors of the country by 2050, and help to decarbonise other parts of the economy, such as transport [75]. FirstGas project the hydrogen demand in 2050 to be 42 TWh and have announced plans to decarbonise the gas pipeline network with the aim of blending green gas (including H_2 and biogas) into the natural gas network from 2030 [24,75]. If we assume that the 2050 annual hydrogen demand for A-NZ will be in the range 15–42 TWh, and that storage requirements are similar to the present, that is, 10% of the total energy demand, then this amounts to 1.5 to 4.2 TWh of useable UHS (not including cushion gas requirements).

Salt caverns are currently the only proven method for storing and recovering high-purity H_2, yet salt deposits do not occur in A-NZ. There are, however, numerous Cretaceous–Cenozoic sedimentary basins, and UHS in porous formations is considered the most viable large-scale hydrogen storage option for the country [24]. Taranaki Basin is the only sedimentary basin in A-NZ with commercial petroleum production, and has been extensively studied, providing numerous open-file datasets that could be utilised in the investigation of UHS (e.g., core, seismic, well logs, production and pressure data etc.). It therefore represents an excellent region to study the technical requirements for UHS and to develop best practices for geostorage prospectivity analysis. The existing petroleum infrastructure and growing renewable (notably wind) electricity resources makes Taranaki well positioned to emerge as a major hydrogen hub in A-NZ and globally.

3.2. Taranaki basin geology

Taranaki Basin contains up to 11 km of mid-Cretaceous–Cenozoic strata and is bound along its eastern margin by the buried, crustal-scale Taranaki Fault System [76,77] (Fig. 2A). Basin development was initiated in the mid-Cretaceous associated with rifting prior to breakup of the eastern margin of Gondwana and formation of the Tasman Sea [76,78,79]. Deposition of syn-rift sediments was followed by a prolonged period of relative tectonic quiescence, with a post-rift passive margin persisting through the late Paleocene–Eocene [76,80]. Subduction and arc magmatism started at the end of the Eocene, and contraction accelerated through the Miocene creating trapping folds in the basin [81,82].

The eastern and southern parts of Taranaki Basin are within the active plate boundary deformation zone, and have been affected by complex overprinting of extensional and contractional tectonic processes [76] (Eastern Mobile Belt on Fig. 2A). Many of the anticlinal structures that have been targeted for petroleum exploration occur in this region, and include the Tarata Thrust Zone beneath eastern Taranaki Peninsula [76,77]. An active volcano (Mt Taranaki on Fig. 2A) is located on the Taranaki Peninsula, west of the Tarata Thrust Zone. By comparison, the western parts of Taranaki Basin have remained relatively undeformed since the latest Paleocene [79] (Western Stable Platform on Fig. 2A), and deposition is largely characterised by progradational sedimentation on a regionally subsiding seafloor [76].

The stratigraphy of Taranaki Basin is illustrated in Fig. 2B, which shows the distribution of reservoir and sealing formations relative to basin history. Proven commercial reservoir intervals range from Paleocene to Pliocene age and consist of a wide range of sandstone facies (fluvial, marginal–shallow marine, and deep marine), characterised by variable reservoir mineralogy, quality, and diagenetic alteration. Sandstone composition and quality is strongly related to sediment provenance and basin history, with older Paleogene reservoirs generally coarser-grained, and comprising a relatively mature quartzo-feldspathic composition compared to the younger, finer-grained and immature, active margin, Neogene reservoirs [83]. The Tikorangi Limestone is the only proven carbonate reservoir in the Taranaki Basin, and is characterised by extremely poor matrix permeability with reservoir quality reliant on fracture porosity. Proven sealing caprocks are primarily Paleocene–Eocene offshore silty mudstones, Oligocene deep marine calcareous mudstones/limestones (where unfractured), and Miocene–-Pliocene deep marine mudstones [76].

3.3. UHS options in Taranaki basin

3.3.1. Depleted oil and gas reservoirs

Depleted oil and gas reservoirs are porous formations where the pore space contains residual hydrocarbons as well as an aqueous phase, following production. Depleted reservoirs generally have well-identified geological structures, proven reservoir quality, a proven caprock, and existing infrastructure, and therefore provide good options for upscaling hydrogen geostorage to an industrial scale. These reservoirs are usually supported with an aquifer at the bottom or side(s), from which the pore volume may have been variably filled, depending on the drive mechanism for the particular reservoir. Residual gas within a depleted gas reservoir might be beneficial for UHS if it provides pressure support as the cushion gas [4,6,37], or a disadvantage if mixing with the remaining natural gas reduces the H_2 purity [11,51]. Generally, residual liquid hydrocarbons (oil/condensate) in a potential UHS site is considered to be more problematic than natural gas due to low recovery factors, the possibility of chemical reactions, dissolution of H_2, and reduction of H_2

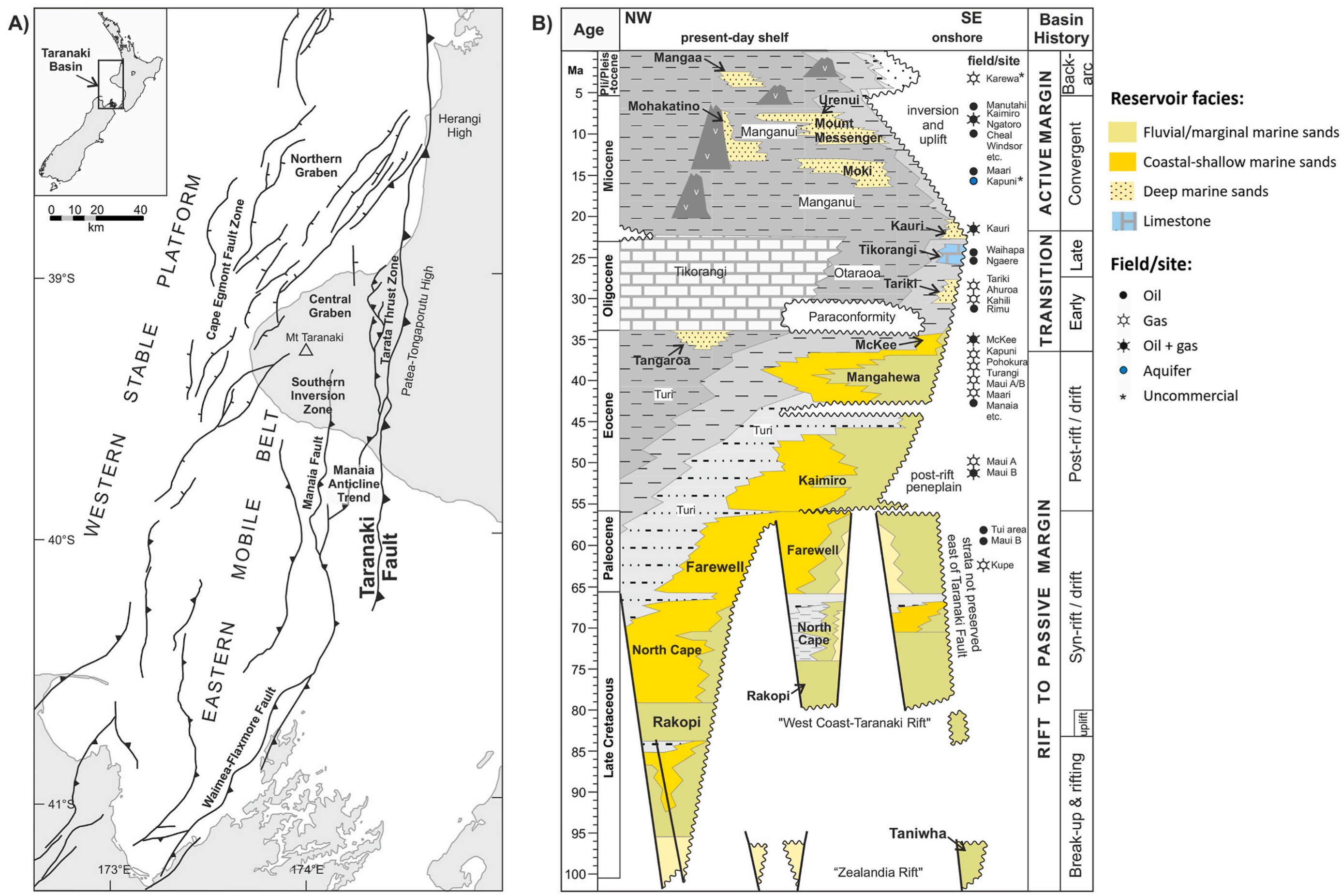


Fig. 2. A) Taranaki Basin map showing the main structural elements. **B)** Lithostratigraphic nomenclature, stratigraphic succession, and petroleum fields in Taranaki Basin relative to basin history; modified from King and Thrasher [76] and Strogen et al. [79].

purity [11,23].

Taranaki is an oil and gas/condensate province, with over 30 petroleum fields representing potential UHS sites and representing over 750 TWh of hypothetical potential H_2 storage capacity (Fig. 3). Most commercial discoveries are located onshore in a zone immediately west of the Taranaki Fault (Eastern Mobile Belt on Fig. 2A), with fewer discoveries located in offshore western parts of the basin (including the giant Maui Field with 4465 PJ/1350 PJ gas/oil reserves [84]; Fig. 4). Gas/condensate has been produced from the largest structures and oldest reservoir intervals (Paleogene), which represent the rift to passive margin and early contractional stages of basin history (Fig. 2B); oil is typically more prevalent in younger active margin reservoirs (Neogene), often within smaller structures and at shallower burial depths. Published data by MBIE [84] suggest that although many fields are still in production, the lifetime for these fields is limited and most operations are likely to cease production between 2030 and 2050. Early identification of potential oil and gas fields due for decommissioning in the next 10–20 years is essential if the projected annual hydrogen demand is to be realised and decarbonisation goals are to be met.

3.3.2. Deep aquifers

Aquifers are porous formations where the pore space is filled by fresh or saline water; geostorage is generally limited to saline aquifers due to the risk of contamination of potable aquifers. UHS in a deep saline aquifer requires the same conditions as a depleted oil or gas reservoir, namely good reservoir properties, and a trap and caprock (top seal) to prevent leakage. As H_2 is injected into an aquifer, some of the water will be displaced (downward or sideways) due to the density difference and immiscibility between gas and liquid, which increases the pore fluid pressure [12]. This is technically more challenging than storage in depleted hydrocarbon reservoirs [47] and would also require high reservoir permeability; Tarkowski et al. [21] suggest a minimum permeability of 100 mD for gas storage in water-bearing rocks. UHS in a deep aquifer would also require more cushion gas compared to depleted hydrocarbon reservoirs (e.g., 80% of the total gas volume [14,21] compared to ~30–50% for depleted fields [22]), which would increase installation costs and decrease the effective H_2 storage volume. However, the absence of hydrocarbons would have the benefit of being able to maintain H_2 purity (subject to possible mineral and/or microbial effects) where H_2 could serve as the cushion gas.

There are many potential sites for UHS in deep aquifers in Taranaki Basin, and the total storage capacity of deep aquifers is understood to be much greater than that of the oil and gas reservoirs. However, the main issue with these sites is the more limited geological data required for assessing site suitability, together with the lack of proven trap, reservoir and caprock. Aquifers will therefore be significantly more expensive to appraise and develop than depleted oil and gas reservoirs due to the uncertain geological constraints and separation from natural gas infrastructure. As such, deep aquifers are considered a lower priority for demonstrating technical feasibility of UHS in A-NZ and should be explored once UHS in geological formations has been proven.

4. Methodology

UHS site evaluation has been undertaken on all significant past and present depleted/depleting fields in Taranaki Basin, one undeveloped (non-commercial) gas discovery, and one deep aquifer site (Fig. 4). Geological suitability of a storage site is dependent on many factors that

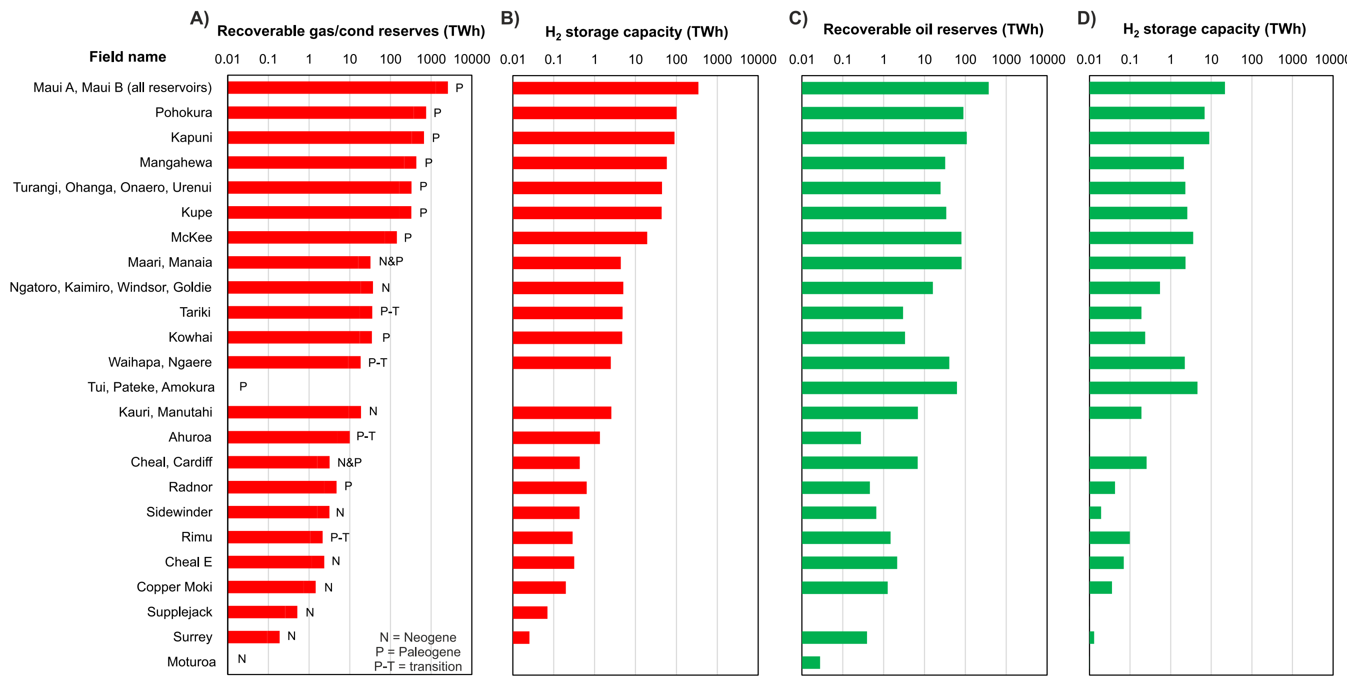


Fig. 3. Recoverable reserves for **(A)** gas/condensate and **(C)** oil fields in Taranaki Basin (logarithmic scales), with estimated equivalent H_2 storage (**B & D** respectively). Storage capacity for all reservoirs in single or combined fields is based on 2P total recoverable hydrocarbon reserves published in MBIE Energy in New Zealand (2021; 2017 for Tui, Pateke, Amokura; 2018 for Moturoa) https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/, and FirstGas [75] for Ahuroa. Refer to supplementary files and Table 6 for information on calculation of estimated H_2 storage capacity.

have been discussed in several peer-reviewed publications [3,6,11,12, 21–23,36]. Here, we have approached prospectivity analysis using criteria-driven processes based on the current understanding of technical requirements for UHS. We introduce two methodologies for integrating the assessments of an expert panel on these criteria and their relative importance. The panel was composed of ten geoscientists with differing backgrounds and expertise including sedimentology, reservoir geology, geoenergy, petroleum geology, structural geology, geophysics, reservoir engineering, engineering geology, paleontology, volcanology, and geochemistry. Key parameters, criteria and weightings, were first assessed by the panel to provide a consistent and objective approach across all evaluated sites. Subsequent consultations included a series of dedicated discussions focused on reviewing sites and scoring values for the identified parameters.

Eighteen technical parameters were identified for evaluation, which are broadly subdivided into the following groups: (1) site basics, (2) reservoir injectivity, (3) H_2 containment, (4) H_2 reactivity/contamination, and (5) data availability/quality. Some parameters require specific (quantifiable) conditions, whilst others are qualitative and are evaluated based on whether conditions are favourable for installing a UHS site. The main technical considerations for UHS and how they have been applied in our evaluation of potential UHS sites in Taranaki Basin are summarised in Table 1. Detailed information on the rationale for parameters and their criteria is provided in supplementary data file 1, with site details, associated parameter results and data references in supplementary data file 2.

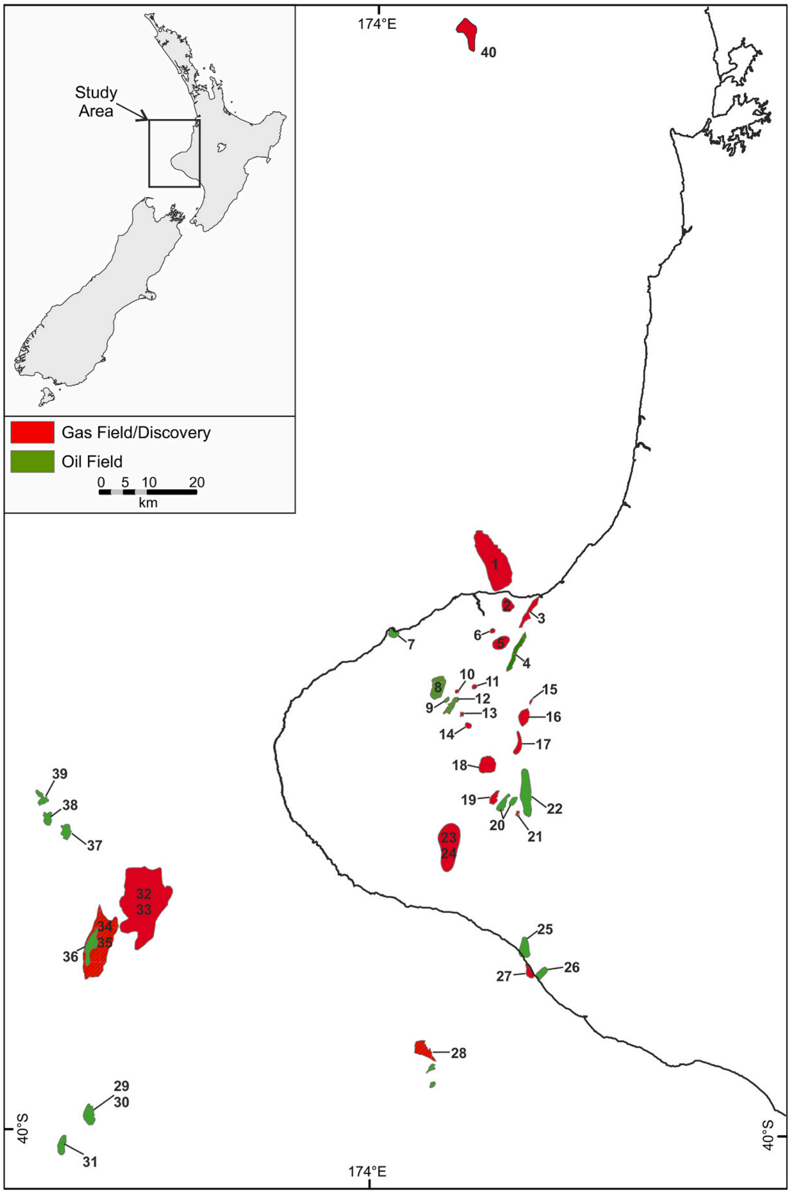
Potential H_2 storage capacity is one of the key parameters used in our site evaluation and has been estimated from documented recoverable petroleum reserves by using a hydrogen energy conversion factor for natural gas [22] or an equivalent hydrogen mass for oil volume based on specific reservoir temperatures and pressures [86]. The storage capacity of very large prospects has been assessed for potential smaller compartments using full field reserves data and/or an evaluation of publicly available legacy data (e.g., individual reservoir reserve estimates, production data, reservoir models etc.). Similarly, legacy datasets have been reviewed to assess the potential capacity of specific sites where recoverable reserves are documented for combined fields, or where there is no reserves information (undeveloped sites). These methods and results are presented in supplementary data files 1 and 2, with detail on H_2 storage capacity estimates for large prospects requiring smaller compartments presented in supplementary data file 3 (see also Table 6).

The methodology applied is heavily dependent on data quality and availability, and we have specifically used parameters and criteria that are quickly and easily assessed from publicly available datasets (e.g., Ref. [94]), and do not require detailed technical field appraisal. Both approaches to prospectivity analysis can be adapted for different sedimentary basins based on geological characteristics of the region, and project-specific requirements.

4.1. Decision tree approach to site evaluation

A binary yes-or-no decision tree technique was used to evaluate the various site options in Taranaki. A series of binary decisions was first considered, based on criteria and values of geological evaluation parameters considered applicable for UHS (Table 1). A hierarchical model was subsequently constructed, whereby the most fundamental decisions were posed first.

The tree starts at the root node, storage size, which we propose is an important factor to consider for UHS in A-NZ. Property values have been assigned to each node, and in most cases the decisions relate to a yes/no answer for criteria that we consider pertinent for UHS. Each branch of the decision tree generates a new node; square leaf nodes indicate another decision to be made, while circle leaf nodes indicate a chance event or unknown outcome. Questions posed by the square leaf nodes and their thresholds, where quantitative, are shown on Fig. 5 (also refer to supplementary data file 1). Four types of circle leaf node have been assigned as follows: red = site not considered further, orange = unlikely to be economic, yellow = additional information required, green = preferred option. "Additional information" has been recommended where the datasets and/or the knowledge is deemed inadequate for



No.	Site Name	Reservoir
1	Pohokura	Mangahewa
2	Turangi	Mangahewa
3	Ohanga/Onaero	Mangahewa/McKee
4	McKee	McKee
5	Mangahewa	Mangahewa
6	Kowhai	Mangahewa
7	Moturoa	Matemateaonga
8	Kaimiro	Mount Messenger
9	Goldie	Mount Messenger
10	Windsor	Mount Messenger
11	Supplejack	Mt Mess and Moki
12	Ngatoro	Mount Messenger
13	Sidewinder	Mt Mess and Moki
14	Surrey	Mount Messenger
15	Kahili	Tariki
16	Tariki	Tariki
17	Ahuroa	Tariki
18	Radnor	Mangahewa
19	Cardiff	Mangahewa
20	Cheal/Cheal E	Urenui and Mt Mess
21	Copper Moki	Mt Mess and Moki
22	Waihapa/Ngaere	Tikorangi
23	Kapuni	Moki
24	Kapuni	Mangahewa
25	Rimu	Tariki, Rimu lst, bsmt
26	Manutahi	Matemateaonga
27	Kauri	Kauri
28	Kupe	Farewell
29	Maari	Moki
30	Maari	Mangahewa
31	Manaia	Mangahewa
32	Maui A	Mangahewa
33	Maui A	Kaimiro
34	Maui B	Mangahewa
35	Maui B	Kaimiro
36	Maui B	Farewell
37	Tui	Farewell
38	Amokura	Farewell
39	Pateke	Farewell
40	Karewa	Mangaa

Fig. 4. Map showing location of 40 assessed sites for UHS in Taranaki Basin, including all significant past and present petroleum fields; site 40 is an uncommercial gas discovery, and site 23 has no proven hydrocarbons and represents a deep aquifer site. Petroleum field locations from NZP&M.

assessment. "Unlikely to be economic" has been applied to those sites where the geological features are considered unfavourable or challenging (e.g., storage size is too small, or burial depth is too deep). However, all options would require a full economic assessment after completing site characterisation and before proceeding with UHS.

This approach efficiently evaluates the feasibility of potential sites and their respective fulfilment of the objective according to quantitative or qualitative and deterministic criteria. Each decision (square leaf node) has been assigned a number, starting at one for the root node, to compare potential UHS site positions on the tree.

4.2. Matrix approach to site evaluation

A criteria-driven matrix approach has historically been used by the petroleum industry for volumetric assessments and prospect analysis (e.g., Refs. [95,96]), and more recently to identify and prioritise sites for CCS [26,97,98]. We have applied a similar weighted decision matrix approach to potential UHS sites in Taranaki to compare results with the decision tree and generate a numerical ranking of sites. An initial site screening was first applied, based on selected parameter threshold criteria that we consider minimum requirements for the successful deployment of UHS in A-NZ. These are: H_2 capacity 1–20 TWh (working gas + cushion gas), top reservoir depth >1 km, and mean reservoir permeability >5 mD (refer Table 1).

The minimum and maximum storage capacity criteria are based on predicted energy storage requirements for A-NZ (see section 3.1). The minimum depth criterion (1 km) is also specific to A-NZ, whereby shallow reservoirs (<1 km) are very poorly consolidated and have typically experienced drilling problems during hydrocarbon production. It is therefore expected that repeated injection and withdrawal cycles, as required for UHS, will result in major issues related to reservoir and caprock degradation. While permeability of the A-NZ reservoirs is highly variable, several fields produce natural gas from tight reservoirs (e.g., Mangahewa, Turangi), where the average permeability is low (<1–5 mD). A fairly low average permeability of 5 mD was selected as the minimum criterion to exclude most of these tight gas reservoirs, which generally require fracture stimulation, while acknowledging that a lower permeability is expected for producing H_2 compared to natural

Table 1
Technical parameters and the assessment methods applied to UHS prospectivity analysis. The main technical considerations for each parameter and how they have been applied to Taranaki are summarised, with details provided in supplementary data file 1.

Technical Group	Technical Parameter	Technical Considerations	Application in Taranaki	Assessment Method
Site Basics	**1) Structural style - trap**	• Defined as structural, stratigraphic, or combined; • Trap complexity increases risk of closure & storage capacity; • Fault rock increases trap uncertainty; • A stratigraphic component requires a well-constrained geological model.	Dominated by structural traps formed by compressional tectonics; good–poor: • Simple 4-way dip anticline; • 3-way dip anticline with fault seal; • Anticline with fault compartmentalisation; • Overthrust anticline; • Multiple thrust slivers.	Qualitative: expert elicitation
	2) H_2 storage capacity	• Seasonal H_2 storage cycles should have the capacity to last several months [4,9] • This requires larger storage capacity than tanks and salt caverns [12,46,85] • However, limiting the size of the storage container will have economic and operational advantages • We suggest optimal storage capacity should be based on site-specific energy requirements	• H_2 storage capacity is estimated from recoverable petroleum reserves using gas to H_2 recovery factor [9,22], or oil volume to H_2 factor based on local conditions [86]; • Sites or compartments with **capacities of 1–20 TWh H_2 are considered for UHS in Taranaki** (working + cushion gas); • New Zealand UHS requirements can be met over the short term by 1–3 sites providing combined storage of 5–10 TWh H_2.	Quantitative (TWh calculated)
	3) Reservoir porosity	• Reservoir porosity is a measure of free space in a rock that can potentially be used to store gas [21]; • Total porosity is routinely measured on samples from hydrocarbon wells; • Total porosity ≠ effective porosity and is not a direct measure of storage capacity.	• Core porosity data is provided in well reports; • Effective porosity calculations are not available for all sites; • It is assumed that reservoirs with higher (average) total porosity are favourable for UHS.	Quantitative (average measured %)
	4) Storage depth	• Deeper sites (with higher T&P) provide more H_2 storage capacity than shallower sites [22,87], but this is offset by the cost of drilling deep [26]. Previous authors have suggested: • UHS should be in the range 500–2000 m [2,36]; • Offshore UHS should be >1.5 km to ensure H_2 densities of 10 kg m^{-3} [87].	• Shallow reservoirs in Taranaki comprise poorly–unconsolidated sands and are unsuitable for H_2 storage; **minimum depth to top reservoir of 1 km has been applied;** • **Optimal depth is considered to be 1.5–3.5 km** for UHS in Taranaki but with many good reservoirs in the better consolidated and more deeply buried Paleogene strata.	Quantitative (km to top reservoir)
Reservoir Injectivity	**5) Reservoir permeability**	• Reservoir permeability is the ability of a porous medium to transmit fluid when saturated by the fluid [88]; • Permeability is routinely measured on samples from hydrocarbon wells; • Higher permeability = higher injectivity [87]; • Low viscosity of H_2 will result in enhanced mobility compared to natural gas or CO_2 [6].	• Permeability is provided in well reports; • It is assumed that reservoirs with higher permeability are favourable for UHS; • **A minimum (average) permeability of 5 mD has been applied;** • No differentiation has been made at this stage for depleted hydrocarbon fields and deep aquifers.	Quantitative (average measured mD)
	6) Gas production rates	• Gas production rate represents the rate per unit time that natural gas is produced; • It is generally proportional to reservoir permeability; • H_2 can be withdrawn and injected at higher volume rates than natural gas [16].	• Maximum historical yearly gas production rates and maximum 2021 rates are provided by MBIE [84]; • It is assumed that higher gas production rates are favourable for UHS.	Quantitative (max yearly TJ/day)
	7) Stratigraphic heterogeneity	• Stratigraphic heterogeneity refers to lithological complexity (e.g., bed thickness); • High heterogeneity can result in injectivity and operational issues (e.g., pressure compartments); • Need to consider depositional facies/lithology & faults with clay gouge.	• A preliminary qualitative assessment has been based on available well reports; • Quality and quantity of pressure, facies and geometry data is highly variable; • Sites with low heterogeneity are favoured over complex sites with numerous pressure compartments.	Qualitative: expert elicitation
	8) Multiple production pools	• Multiple production pools refers to several small accumulations produced under the same field name; • Multiple (small) production pools will result in lower injectivity due to reservoir compartmentalisation.	In Taranaki multiple (small) pools include: • Small pools in the same structural closure but within different formations; • Pools at different levels of one formation; • The same reservoir interval but within structurally discrete traps.	Qualitative: expert elicitation
	9) Potential formation damage	• Formation damage during drilling can cause production problems and impair injectivity by reducing permeability in the near-wellbore region [89]; • Need to consider how the formation will perform over the multiple injection and production cycles required for UHS.	• A preliminary qualitative assessment of potential formation damage has been based on well reports detailing reservoir texture and composition; • In Taranaki the main considerations are the potential for sand production, fines migration and presence of swelling clays.	Qualitative: expert elicitation
	10) Aquifer risk	• A strong aquifer in a depleted petroleum field will be detrimental to H_2 injectivity [21]; • Water production in UHS simulations occurs more quickly in the water zone compared to oil or gas zones [51]; • Fields using depletion drive recovery are favourable to aquifer support recovery [90].	• A preliminary qualitative assessment of aquifer risk has been based on well reports; • However, public data on aquifer support and water influx are not easily accessible; • Aquifer risk has been qualitatively ranked, with a high uncertainty associated with this parameter.	Qualitative: expert elicitation

(*continued on next page*)

Table 1 (*continued*)

Technical Group	Technical Parameter	Technical Considerations	Application in Taranaki	Assessment Method
H_2 Containment	**11) Hydrocarbon phase**	• The composition of the depleted, trapped hydrocarbon will have specific physico-chemical properties different to H_2 [19–24]; • Gas systems generate higher buoyant pressures than oil systems suggesting that a depleted gas reservoir may be more likely to hold back H_2 than a depleted oil reservoir; • H_2 is more diffusive, with lower viscosity and density, and is hence potentially more mobile than methane or CO_2 [6,21]; • H_2 has a lower solubility in water than other gases, reducing risk of dissolution into the seal [21].	• Depleted gas reservoirs are favoured over depleted oil reservoirs on the premise that caprocks proven to contain natural gas are more likely to contain H_2 than caprocks for liquid hydrocarbons; • A gas cap in a mixed phase reservoir is considered more favourable than an oil only reservoir; • Many of deeper (older) reservoir intervals in Taranaki contain gas; shallow (younger) reservoirs are oil prone (updip oil spill [91,92]); • Deep aquifer sites have no proven containment.	Oil, gas/cond, 2-phase, deep aquifer
	12) Top seal risk	• Top seal is dependent on lithology/facies (composition, continuity, quality) and wells; • Seal quality is based on capillary pressure & pore size distribution measurements [93]; • A given caprock is likely to retain at least as large a vertical column of H_2 as natural gas [22,87] and H_2 losses through caprocks are likely to be low [22,65]; • Further work is required to assess the impact of H_2 on seal properties [22,23].	• Effective hydrocarbon seals are proven in the depleted fields in Taranaki; • A preliminary qualitative assessment of top seal capacity & continuity has been based on available well reports and an understanding of facies trends; • The number of well penetrations into the reservoir interval has been included in the assessment for potential top seal risk.	Qualitative: expert elicitation
	13) Fault seal risk	• Fault seal risk is difficult to determine and requires evaluation of the fault shale gouge ratio and buoyancy pressures [93]; • An individual fault can locally provide a seal (e.g., pressure compartments) or a leakage pathway; • Fault and seal integrity can be compromised by drilling activity.	• Detailed fault analysis in Taranaki is generally sparce and inconsistent, and a preliminary qualitative assessment has been based on available well reports; • It is assumed that sites with extensive faulting through the caprock and/or with a fault-seal component to the trap are less favourable for UHS.	Qualitative: expert elicitation
H_2 Reactivity/ Contamination[a]	**14) H_2 – CO_2** **15) H_2 – coal** **16) H_2 – oil** **17) H_2 – carbonate**	• Work to date suggests that there is likely to be little reaction between siliciclastic minerals and H_2 over UHS time-scales [32,57–61]; • However, the potential for biochemical reactions is considered a major uncertainty [63,65] with H_2 providing the main source of energy for carbon-based minerals and hydrocarbons [21,22,32,60,65,68], sulphates and sulphides [12,23,57,61,65]; • These reactions can lead to H_2 losses and contamination [3,12,23,55,63,65], and/or changes in rock properties [56]; • Further work is required to assess potential reactivity under reservoir conditions [57,59,63].	• A qualitative, site-specific assessment has been made for reservoir/seal composition. In Taranaki: • Reservoir and seal rocks are dominated by siliciclastic minerals; • CO_2 content is highly variable; • Coals/carbonaceous matter is relatively common in Paleocene-Eocene reservoirs; • Carbonate cements are relatively common in Oligocene and Miocene strata; • Sulphates are generally not present; • Pyrite is generally minor ($\leq$1%); • It is assumed that reservoir and seal rocks with low CO_2, coal, carbonate and oil are favourable for UHS.	Qualitative: expert elicitation
Data	**18) Data availability/ quality**	• Data availability, vintage and quality of datasets are of paramount importance for UHS prospectivity analysis.	• In New Zealand there is a requirement to lodge data with MBIE, which becomes publicly available after 5 years; • Potential sites have been qualitatively assessed for data availability and quality.	Qualitative: expert elicitation

[a] reactivity of H_2-sulphide/sulphate would need to be addressed in the site characterisation work.

gas (due to the lower viscosity of H_2) [6]. An effective trap and top seal are two of the most important geological factors for UHS, but these parameters were not included at the preliminary screening stage given that UHS prospectivity has focused on developed fields with proven hydrocarbon accumulations (hence inferred trap and caprock). However, a minimum top seal thickness and/or maximum seal permeability would be recommended for screening of deep aquifers where trap and containment are largely unknown.

Sites that met the matrix-qualifying criteria have been assessed and ranked based on the geological parameters outlined in Table 1. For these sites, a value from 1 (poorest) to 3 (best) was assigned to each parameter. All parameters were also given a weighting from 1 (lowest) to 5 (highest), reflecting our understanding of the relative importance of different attributes for UHS. Confidence scores (high, mid, low) are provided for both parameter values (by site) and weightings. The rank score for each potential storage site was calculated as a value between 0 and 1 by summing the normalised, weighted parameter values (normalised criterion value x normalised weighting). As such, the score reflects a combined assessment of the overall technical suitability for UHS at each site. The data confidence and weighting confidence scores are not factored into this technical score but provide a measure of the uncertainties relating to individual sites and parameters.

This weighted decision matrix approach is subject to the biases of the authors and is very much dependent upon our current understanding of the most favourable parameters for UHS. The method used was preferred over a paired comparison matrix that assesses relative importance of two factors [4,26] because of the considerable uncertainties that remain regarding H_2 behaviour in the subsurface [6,22,23]. For example, there are high uncertainties with different H_2 reactivity parameters and how they will individually impact H_2 purity (Table 1), and we consider a pairwise comparison of these parameters would be more susceptible to author bias than the broad low–high (1–5) weighting scheme we have applied. We have undertaken some sensitivity analysis to address the uncertainty with parameter weightings, which assesses how rank score changes with different weightings. Sensitivity analysis was concentrated on parameter weightings that have the greatest uncertainties, and in this way, we were able to investigate how bias might influence the results. Weighting factors are liable to be changed and adapted as our understanding of the importance of specific parameters and criteria for UHS evolves.

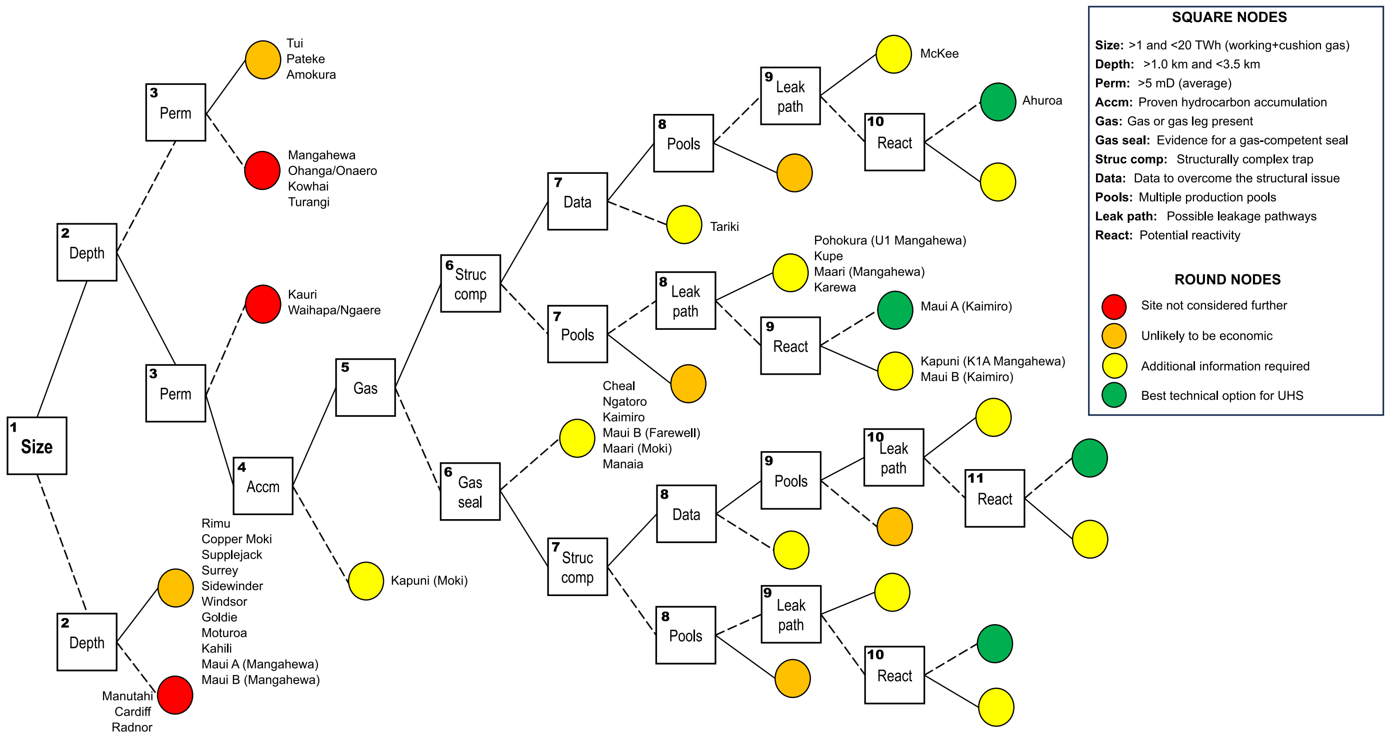


Fig. 5. Summary decision tree for evaluating the technical suitability of UHS sites. Square nodes represent questions with numbers reflecting the tree position. Solid line branches represent a “yes” response and dashed branches represent “no”. The position of sites is shown on the tree by the site name; reservoir interval in parentheses where there are multiple reservoir intervals.

5. Site prospectivity

A total of 40 sites have been assessed in this work, which are referred to by their site name and reservoir interval (site, reservoir; Fig. 4). They comprise gas fields, oil-bearing fields with gas caps, oil fields, one deep aquifer stratigraphically located above a commercial field (Kapuni, Moki), and one site with proven, but undeveloped (non-commercial) gas (Karewa, Mangaa). Sites without commercial production have some subsurface geological data, but are poorly characterised compared to the depleted oil and gas reservoirs. Site details, parameter results and data references are provided in supplementary data file 2.

5.1. Decision tree results

The summary decision tree is presented as Fig. 5, which illustrates the position of all 40 potential sites. Sites that are positioned high on the tree structure (e.g., nodes 2–3) are considered to have poor geological characteristics for UHS. They include sites ending on a red node (fail), or an orange node (unlikely to be economic), based on whether they meet the minimum and maximum size criteria (node 1), depth criteria (nodes 2), and minimum permeability criterion (nodes 3).

To progress down the main part of the tree structure the UHS site must have a proven oil or gas accumulation (node 4), which demonstrates a working trap-reservoir-caprock. If there is no proven accumulation the site will stop at node 4 and require additional information (yellow node). In the current study we have only included one deep aquifer where there are no proven hydrocarbons (Kapuni, Moki). However, any other deep aquifer that meets the storage size, permeability and depth criteria would finish at this node.

Sites that present further down the tree structure are considered more suitable for demonstrating UHS, with two branches relating to 1) natural gas reservoirs, including gas caps, and 2) oil only reservoirs. Natural gas reservoirs occupy the most favourable tree branch for UHS. Parameters that are considered along this branch comprise structural style, data availability/quality, number of production pools, potential for fault or top seal leakage, and potential reactivity. This represents a simplified set of parameters compared to the matrix approach (section 5.2). All sites that proceed along the oil only reservoirs branch are considered to have potential to leak gas through the seal, finishing at node 6, and requiring additional information (yellow node; e.g., Cheal). However, a greater understanding on H_2 mobility is required to assess the competence of seals for UHS, and the position of oil fields may change depending on results from future research.

Table 2 summarises the decision tree results, which lists nine eliminated sites (red nodes), two candidates with favourable geological characteristics (green nodes), and the relative position of other sites. The top two candidates are the natural gas storage site Ahuroa (Ahuroa, Tariki), and the offshore Maui A field (Maui A, Kaimiro). However, it is noted that the Ahuroa tree position is dependent upon provision of confidential data at site characterisation stage. Other potential UHS sites (finishing on nodes 7–9) are all Paleogene depleted gas or gas-cap reservoirs, which have ended on a yellow node for potential reactivity, H_2 leakage (caprock or fault), or data availability.

The position of sites on the decision tree is partly controlled by the parameter order (i.e. order that questions are posed). For example, if a question posed relatively high in the tree structure is switched with a question posed low in the tree structure (e.g., permeability switched with potential reactivity), then the resultant node position of sites would be different, although the node colour would be the same (e.g., yellow for additional information required, or green for preferred option). Site position on the decision tree is therefore dependent upon our current understanding of the most favourable parameters for UHS (e.g., sufficient permeability is considered more favourable for demonstrating UHS than the absence of potential reactants).

5.2. Matrix results

A list of criteria and relative weightings for the 18 technical parameters used in site ranking is presented in Table 3. The quality and quantity of data used to assess potential storage sites has a significant

Table 2
Technical suitability of sites for UHS in Taranaki Basin based on a decision tree approach.

#	Site Name	Reservoir Interval	Decision Tree Node Position and Results		
1	Ahuroa[a]	Tariki	**10**	**Green Node = Geologically Preferred Candidates**	
2	Maui A	Kaimiro	**9**		
3–5	Kapuni N field	Mangahewa (K1A)	**9**	**Yellow Node 9**, potential reactivity	**Geologically Possible Candidates: Additional information required**
	Maui B	Kaimiro	**9**		
	McKee[a]	McKee	**9**	**Yellow Node 9**, potential leakage	
6–9	Kupe	Farewell	**8**	**Yellow Node 8**, potential leakage (fault or seal)	
	Pohokura	Mangahewa (U1)	**8**		
	Maari	Mangahewa	**8**		
	Karewa	Mangaa	**8**		
10	Tariki	Tariki	**7**	**Yellow Node 7**, data needed to address uncertainties	
11–16	Maui B	Farewell	**6**	**Yellow Node 6**, oil reservoir with no gas containment	**Lower UHS potential based on current understanding: Additional information required**
	Manaia	Mangahewa	**6**		
	Maari	Moki	**6**		
	Kaimiro	Mount Messenger	**6**		
	Ngatoro	Mount Messenger	**6**		
	Cheal and Cheal E	Urenui & Mount Mess	**6**		
17	Kapuni	Moki	**4**	**Yellow Node 4**, no proven containment	
18–31	Tui area[b]	Farewell	**3**	**Orange Node 3**, deep reservoir	**Unlikely to be economic**
	Maui A	Mangahewa	**2**	**Orange 2**, container size too large	
	Maui B	Mangahewa	**2**		
	Rimu	Tariki, Rimu Lst, Basement	**2**	**Orange Node 2**, container size too small	
	Copper Moki	Mt Mess and Moki	**2**		
	Supplejack	Mt Mess and Moki	**2**		
	Surrey	Mount Messenger	**2**		
	Sidewinder	Mt Mess and Moki	**2**		
	Windsor	Mount Messenger	**2**		
	Goldie	Mount Messenger	**2**		
	Moturoa	Matemateaonga	**2**		
	Kahili	Tariki	**2**		
32–40	Kauri	Kauri	**3**	**Red Node 3**, failed on permeability	**Site not considered further**
	Waihapa/Ngaere	Tikorangi	**3**		
	Mangahewa	Mangahewa	**3**	**Red Node 3**, failed on depth and permeability	
	Ohanga/Onaero	Mangahewa/McKee	**3**		
	Kowhai	Mangahewa	**3**		
	Turangi	Mangahewa	**3**		
	Manutahi	Matemateaonga	**2**	**Red Node 2**, failed on container size and depth	
	Cardiff	Mangahewa	**2**		
	Radnor	Mangahewa	**2**		

[a] site position dependent upon confidential data.
[b] Tui area comprises three separate fields (Tui, Pateke, Amokura).

Table 3
Criteria and relative weightings applied to parameters assessed for UHS prospectivity analysis, Taranaki Basin. Weighting values from 1 (low) to 5 (high). Normalised weighting = weighting value/sum of weighting values.

Technical Group	Technical Parameter	Criteria and Value			Weighting	Weighting Confidence	Normalised Weighting
		Poor - 1	Mid - 2	Good - 3			
Site Basics	1) Structural style	Complex	Mid	Simple	**3**	High	0.056
	2) Storage capacity (TWh)	15–20	1–2, 8–15	3–8	**4**	Mid	0.074
	3) Reservoir porosity (av. %)	<10	10–15	>15	**2**	High	0.037
	4) Storage depth (km)	1–1.5, >3.5	2.5–3.5	1.5–2.5	**3**	Mid	0.056
Reservoir Injectivity	5) Reservoir permeability (av. mD)	5–10	10–100	>100	**4**	High	0.074
	6) Stratigraphic heterogeneity	High	Mid	Low	**1**	Mid	0.019
	7) Multiple production pools	Many pools	2–3 contacts	Single accumulation	**3**	Mid	0.056
	8) Gas production rates (TJ/d)	<5	5–50	>50	**2**	Mid	0.037
	9) Potential formation damage	Confirmed	Suspected	No indication	**2**	Mid	0.037
	10) Water influx	Confirmed	Suspected	No indication	**1**	Low	0.019
H_2 Containment	11) Hydrocarbon phase	Oil reservoir	Gas cap	Gas reservoir	**5**	Mid	0.093
	12) Fault seal risk	Confirmed	Suspected	No indication	**5**	High	0.093
	13) Top seal risk	Confirmed	Suspected	No indication	**5**	High	0.093
H_2 Reactivity	14) H_2–CO_2 reactivity	>20% CO_2	3–20% CO_2	<3% CO_2	**3**	Low	0.056
	15) H_2-coal reactivity	Common coal	Rare coal	No coal	**2**	Low	0.037
	16) H_2-oil interaction	Common oil	Rare oil	No oil	**3**	Low	0.056
	17) H_2-carbonate reactivity	Common carb.	Locally carb.	Rare carb.	**1**	Low	0.019
Data	18) Data Availability/Quality	Poor	Fair	Good	**5**	High	0.093

influence on the results, and hence has been given the highest weighting (parameter 18, weighting 5). Highest weighting values have also been assigned to parameters that relate to containment, including risk of leakage through top seal or fault seal (parameters 12 and 13), and hydrocarbon phase (whereby a natural gas accumulation is considered more likely to contain H_2 compared to an oil reservoir with no proven gas cap; parameter 11). A high weighting (weighting 4) has been applied to reservoir permeability (parameter 5), which is essential for injectivity and to storage capacity. Lower weightings have been placed on parameters where there remains a high uncertainty with respect to their impact on hydrogen storage, and/or where there is limited information in the database (making comparisons difficult and resulting in high uncertainty). It is anticipated that future research should help to resolve some of these uncertainties, which may result in a revision to the parameter weightings. Additionally, in cases where the data are sparse or of poor quality, collection of new data may ultimately change the site scores.

Site ranking results are presented in Table 4. The top-ranking sites all comprise Paleogene depleted gas or gas-cap reservoirs, with the lowest ranking fields representing younger (Miocene) reservoirs and oil reservoirs from older (Paleogene) accumulations. Typically, the Miocene reservoirs rank low due to their small size, reservoir complexity/compartmentalised petroleum pools (which increases risk associated with reservoir injectivity), and their uncertainty for trapping gas (generally oil is the primary reservoir fluid). Additionally, these Miocene reservoirs are often poorly lithified, which, with the fine grain size, labile and clay-rich composition, makes them prone to reservoir degradation that could worsen over time due to the multiple injection/withdrawal cycles required for UHS.

The lowest matrix score is from the deep aquifer site (Kapuni, Moki) that overlies the commercial Kapuni Field at Mangahewa level. This very low score is primarily due to a significant risk of containment, and uncertainties associated with lack of publicly available data/interpretations. The second site with no commercial discovery (Karewa, Mangaa) is ranked at number 11, above the Miocene plays and some Paleogene oil sites. Karewa has some good quality data, including a 3D seismic survey and single borehole, with data availability and quality better than expected for a deep aquifer site. Data and interpretations are, however, much less detailed than those for a developed field. Critical factors that hinder UHS development of this site relate to the uncertainty with containment (fault and top seal risk), and reservoir quality (heterogeneity, production rates, formation damage).

A list of disqualified sites from the screening stage is provided in supplementary data file 2, with size being the main basis for ruling out potential sites. Many of the sites that are deemed to be too small for anticipated UHS requirements are onshore Miocene oil fields (e.g., Surrey). Several of the stratigraphically older reservoirs produce from deep/low permeability and locally small reservoirs, which would make UHS challenging (e.g., Cardiff) and have also been excluded. Only two sites have been eliminated due to storage capacities that are too large, and where a smaller compartment was not considered possible (Maui A and Maui B, Mangahewa; refer to supplementary data file 3).

5.3. Sensitivity analysis

There is a very small range in matrix scores for the top 10 sites (0.806 to 0.725, Table 4) and site order could change with input from different experts. We have therefore undertaken sensitivity analysis, primarily to investigate the impact of changing parameter weightings where there remains significant uncertainty with the weighting and/or the impact of the parameter on H_2 storage (e.g., H_2 reactivity). We have consistently applied the highest weightings to containment parameters, permeability, storage capacity, and data availability/quality.

A ranking comparison for some of these sensitivity analyses is provided in Table 5. In all cases the top 10 sites are dominated by Paleogene depleted gas or gas-cap reservoirs, with lower ranks associated with the younger Miocene reservoirs. However, there is some variability in the actual rank position for individual sites, which is dependent on the importance placed on different variables for the successful deployment of UHS.

The top three candidates are variably the natural gas storage site Ahuroa (Ahuroa, Tariki), the offshore Maui A field (Maui A, Kaimiro), the onshore Kapuni field (Kapuni, K1A Mangahewa), and the on/offshore Pohokura field (Pohokura, U1 Mangahewa). In most cases, Ahuroa is the preferred candidate, but its position is partly dependent upon high-quality, confidential (UGS) data. An adjacent field (Tariki, Tariki) is broadly analogous to Ahuroa in terms of its structural style, reservoir and seal but has a lower rank score. This result is primarily due to poor data availability/quality at Tariki, and the site rank is liable to change with acquisition of new datasets.

Sensitivity analysis shows that results are impacted by the weightings chosen by the panel and will need to be updated to integrate learnings from new studies as they become available. Based on current knowledge, the ranking matrix suggests that there are multiple sites in Taranaki that are likely to have broadly suitable geological characteristics for UHS.

Table 4
Ranking of sites in Taranaki Basin based on a matrix approach where the site number from Fig. 3 is shown in parentheses. Rank score = sum of weighted parameter values (normalised criterion value x normalised weighting). The ranking matrix addresses geological parameters required for UHS; economic, social/cultural and regulatory issues would need to be separately evaluated for each potential site before proceeding with any pilot project.

#	Site Name (Site Number)	Onshore/Offshore	Hydrocarbon Phase	Reservoir Age	Reservoir Interval	Seal Interval	Rank Score
1	Ahuroa (17)	Onshore	Gas/cond	Oligocene	Tariki	Otaraoa	**0.806**
2	Maui A (33)	Offshore	Gas/cond	Eocene	Kaimiro	Turi	**0.796**
3	Kapuni (24)	Onshore	Gas/cond	Eocene	Mangahewa (K1A)	Turi/Otaraoa	**0.784**
4	Pohokura (1)	Offshore	Gas/cond	Eocene	Mangahewa (U1)	Turi	**0.765**
5	McKee (4)	Onshore	Gas cap to oil leg	Eocene	McKee	Otaraoa	**0.762**
6	Kupe (28)	Offshore	Gas leg with oil rim	Paleocene	Farewell	Otaraoa	**0.756**
7	Tariki (16)	Onshore	Gas/cond	Oligocene	Tariki	Otaraoa	**0.756**
8	Maui B (35)	Offshore	Gas cap to oil leg	Eocene	Kaimiro	Turi	**0.753**
9	Tui area[3] (37)	Offshore	Oil	Paleocene	Farewell	Turi	**0.753**
10	Maari (30)	Offshore	Gas cap to oil leg	Eocene	Mangahewa	Turi/Otaraoa	**0.725**
11	Karewa (40)	Offshore	Uncommercial gas	Pliocene	Mangaa	Manganui	**0.713**
12	Maui B (36)	Offshore	Oil	Paleocene	Farewell	Turi	**0.701**
13	Manaia (31)	Offshore	Oil	Eocene	Mangahewa	Turi/Otaraoa	**0.617**
14	Maari (29)	Offshore	Oil, minor gas	Miocene	Moki	Manganui	**0.611**
15	Kaimiro (8)	Onshore	Oil, minor gas	Miocene	Mount Messenger	Manganui	**0.599**
16	Ngatoro (12)	Onshore	Oil, minor gas	Miocene	Mount Messenger	Manganui	**0.599**
17	Cheal/Cheal E (20)	Onshore	Oil and gas	Miocene	Urenui & Mount Mess	Manganui	**0.574**
18	Kapuni (23)	Onshore	Deep aquifer	Miocene	Moki	Manganui	**0.525**

Table 5
Comparison of site rank based on different weightings applied to selected parameters, where the rank score is shown in parentheses. **A)** Original weightings as presented in Table 3. **B)** Reactivity parameter weightings increased for CO_2 (4), coal (3), oil (4) and carbonate (3). **C)** Reactivity parameter weightings lowered for CO_2 (2), coal (1), oil (2). **D)** Reservoir parameter weightings increased for stratigraphic heterogeneity (3), formation damage (4), structural complexity (4) and aquifer risk (3). Top 10 sites are Paleogene reservoirs for all scenarios and lowest ranked sites are Miocene reservoirs (italics).

#	A) Original Weightings	B) Reactivity – higher weighting	C) Reactivity – lower weighting	D) Reservoir Parameters
1	Ahuroa, Tariki (0.806)	Ahuroa, Tariki (0.811)	Maui A, Kaimiro (0.804)	Ahuroa, Tariki (0.831)
2	Maui A, Kaimiro (0.796)	Maui A, Kaimiro (0.797)	Kapuni, K1A Mangahewa (0.797)	Kapuni, K1A Mangahewa (0.820)
3	Kapuni, K1A Mangahewa (0.784)	Pohokura, U1 Mangahewa (0.774)	Ahuroa, Tariki (0.794)	Maui A, Kaimiro (809)
4	Pohokura, U1 Mangahewa (0.765)	Tariki, Tariki (0.766)	Pohokura, U1 Mangahewa (0.765)	Pohokura, U1 Mangahewa (0.803)
5	McKee, McKee (0.762)	McKee, McKee (0.763)	Maui B, Kaimiro (0.765)	Kupe, Farewell (792)
6	Kupe, Farewell (0.756)	Tui area, Farewell (0.763)	Kupe, Farewell (0.761)	Tariki, Tariki (0.787)
7	Tariki, Tariki (0.756)	Kapuni, K1A Mangahewa (0.757)	McKee, McKee (0.758)	McKee, McKee (0.781)
8	Maui B, Kaimiro (0.753)	Maui B, Kaimiro (0.751)	Tui area, Farewell (0.752)	Maui B, Kaimiro (0.770)
9	Tui area, Farewell (0.753)	Kupe, Farewell (0.737)	Tariki, Tariki (0.742)	Tui area, Farewell (0.770)
10	Maari, Mangahewa (0.725)	Maari, Mangahewa (0.726)	Maari, Mangahewa (0.722)	Maari, Mangahewa (0.757)
11	Karewa, Mangaa (0.713)	Karewa, Mangaa (0.720)	Karewa, Mangaa (0.703)	Maui B, Farewell (0.732)
12	Maui B, Farewell (0.701)	Maui B, Farewell (0.709)	Maui B, Farewell (0.703)	Karewa, Mangaa (0.730)
13	Manaia, Mangahewa (0.617)	*Maari, Moki (0.621)*	Manaia, Mangahewa (0.618)	Manaia, Mangahewa (0.664)
14	*Maari, Moki (0.611)*	Manaia, Mangahewa (0.619)	*Maari, Moki (0.601)*	*Maari, Moki (0.628)*
15	*Kaimiro, Mt Mess (0.599)*	*Kaimiro, Mt Mess (0.605)*	*Kaimiro, Mt Mess (0.595)*	*Kaimiro, Mt Mess (0.596)*
16	*Ngatoro, Mt Mess (0.599)*	*Ngatoro, Mt Mess (0.605)*	*Ngatoro, Mt Mess (0.595)*	*Ngatoro, Mt Mess (0.596)*
17	*Cheal &Cheal E, Uren + MM (0.574)*	*Cheal & Cheal E, Uren + MM (0.588)*	*Cheal &Cheal E, Uren + MM (0.562)*	*Cheal &Cheal E, Uren + MM (0.574)*
18	*Kapuni, Moki (0.525)*	*Kapuni, Moki (0.537)*	*Kapuni, Moki (0.503)*	*Kapuni, Moki (0.546)*

6. Discussion

6.1. Comparison of approaches

Results are compared for the two different multi-criteria decision-making approaches used in UHS prospectivity analysis. The decision tree is a "fast-track" method that provides an evaluation without the need for assessing other sites. Conversely, the matrix approach is a more in-depth assessment and requires parameters for all sites prior to evaluation.

The top two sites for validating the technical feasibility of UHS in A–NZ are the same for both approaches, demonstrating the consistent criteria applied by the expert panel. Most other sites that fall within the top ten options using the decision tree (failing at node 7 or above, Table 2) are also ranked in the top ten on the matrix. The one exception is Karewa, an undeveloped gas discovery, which occurs in the top ten of the decision tree based on proven containment (gas); this site is ranked slightly lower in the matrix (position eleven) because of the uncertainty with the size of the accumulation and the amount of hydrocarbons that might have been leaked. The relatively simple approach of the tree structure does not allow for these more complex questions to be addressed in the analysis.

Generally, the criteria used in both approaches have been consistent and it is therefore not surprising that results for both methods are similar. Small variations in the results partly reflect differences in the application of reservoir depth criteria, and are also partly due to the combination of certain parameters in the decision tree approach.

The decision tree has included a minimum and maximum depth query, which occurs high up in the tree structure and provides the user with a visual prompt that deeply buried reservoirs are unlikely to be economic. We have used a maximum depth of 3.5 km, but this will vary for different geographical locations, and will be dependent on geological, geographical, social, regulatory and economic factors. A maximum depth has not been applied in the early screening stage of the matrix to prevent exclusion of good quality, deep reservoir options. This results in a poorer position on the decision tree for deep reservoirs (e.g., Tui area) compared to the matrix.

Several parameters have been combined on the decision tree, which simplifies the prospectivity assessment and does not accommodate the relative importance of different parameters. For example, a site containing many potential reactants (e.g., CO_2, coal, residual oil, carbonate) is not distinguished on the tree from a site that only has potential reactivity with coal, and the relative impact of H_2–CO_2, H_2–coal, H_2–oil, and H_2–carbonate reactions is not addressed.

Notwithstanding small variations in results for the two approaches, both suggest that based on our current understanding, the most geologically prospective UHS sites in Taranaki Basin are Paleogene reservoirs (rift to passive margin and earliest contractional deposits, Fig. 2B), and that younger reservoirs (active margin deposits) are typically poorer candidates. The one exception to this is the Karewa site (undeveloped, sub-commercial Pliocene reservoir), which is characterised by a simpler structural trap (4-way dip closure) compared to Miocene geostorage prospects, and has a small gas accumulation, compared to oil in most Miocene reservoirs.

Overall, the two sites without commercial hydrocarbons display similar positions for both decision tree and matrix approaches (Karewa, Mangaa positions 6–9 and 11 respectively, and Kapuni, Moki positions 17 and 18 respectively). Deep aquifer sites are downgraded in the matrix due to the absence of proven containment (hydrocarbon phase parameter = 0 where none proven, and top seal risk), with low parameter values typically also put on data availability/quality. If hydrocarbons are unproven, these sites finish early on the decision tree, with advice for more information required (yellow node). While this effectively deals with the Kapuni, Moki deep aquifer (stopping at node 4), the Karewa, Mangaa option has branched further down the tree to finish in a similar position to commercial gas reservoirs (i.e., Pohokura and Kupe, node 8; Fig. 5). These three sites are identified as all having the potential for some breach, but the presence of large gas columns at Pohokura and Kupe are not distinguished from the sub-commercial gas at Karewa.

The strength of the decision tree approach to prospectivity is simplicity, and the ability to apply it without the need for other site information. The decision tree visually demonstrates cause-and-effect relationships, providing a simplified view of complex issues and helps to clarify the choices, risks, objectives and gains. Additional information can be documented on the tree, highlighting any technical issues related to the failure node.

In comparison, the matrix approach provides a numerical rank score that would be beneficial for the large-scale screening of numerous storage sites. The matrix results do not present the user with an understanding of potential UHS issues. However, a visual comparison of site scores can be made using spider diagrams, the shape of which illustrates the strengths and weaknesses for different sites. Spider plots comparing the top five and bottom five ranking sites in Taranaki show that young Miocene reservoirs are characterised by spiky plots, indicative of their highly variable parameter values (Fig. 6). Most Miocene reservoirs score high values for porosity, coal/CO_2 and data availability, but low values

Table 6
Estimated H_2 storage capacity (working gas + cushion gas) for qualifying sites in Taranaki Basin based on recoverable 2P 2021 petroleum reserves from MBIE [84] unless otherwise stated. Natural gas to H_2 storage capacity uses the energy conversion factor of 0.27 [22], and oil to H_2 storage capacity converts oil volume to equivalent hydrogen mass based on specific reservoir temperatures and pressures [86]. Equivalent H_2 storage is recorded using the gas/condensate leg (g), the oil leg (o), or both (g + o); GDT = gas down-to. Illustrations, input data and references used for estimating H_2 storage capacity in large prospects is provided in supplementary data file 3.

Site Name	Reservoir Interval	Hydrocarbon Phase	Gas reserves (TWh)	Oil reserves (TWh)	Equiv. H_2 storage (TWh)	Comment
Large prospects requiring smaller compartments, details in italics						
Maui (A & B)	Mangahewa, Kaimiro, Farewell	Gas/cond, oil	1280	375	369 (g + o)	Full field reserves/storage for 3 reservoirs, 2 sites.
Maui A	*Kaimiro*	*Gas/cond*	*ND*	*ND*	*21.6 (g)*	*Petroleum reserves for individual reservoirs based on legacy reserve estimates; seismic mapping from open file datasets used to demonstrate smaller closures possible in structure (GDT); Maui A, B at Mangahewa level are considered too big.*
Maui B	*Kaimiro*	*Gas cap oil leg*	*ND*	*ND*	*17.8 (g)*	
Maui B	*Farewell*	*Oil*	*ND*	*ND*	*<22 (o)*	
Pohokura	Mangahewa (U1–U4)	Gas/cond	376	90	108 (g + o)	Full field reserves/storage for 4 intervals (U1–U4).
Pohokura	*Mangahewa (U1)*	*Gas/cond*	*ND*	*ND*	*47.8 (g)*	*U1 reserves based on operator reservoir model; smaller closure possible in structure (GDT).*
Kapuni	Mangahewa (K1A-K1E)	Gas/cond	333	108	99 (g + o)	Full field reserves/storage for several intervals (K1A-K1E).
Kapuni	*Mangahewa (K1A)*	*Gas/cond*	*ND*	*ND*	*19.7 (g)*	*K1A reserves based on operator production data; smaller closure possible in structure (GDT).*
Kupe	Farewell	Gas leg oil rim	162	34	46 (g + o)	Full field reserves/storage.
Kupe	*Farewell*	*Gas/cond*	*ND*	*ND*	*36 (g)*	*Storage in gas leg with smaller closure possible in structure (GDT).*
McKee	McKee	Gas cap oil leg	71.7	79.8	23 (g + o)	Full field reserves/storage.
McKee	*McKee*	*Gas/cond*	*ND*	*ND*	*19.4 (g)*	*Storage in gas leg with smaller closure possible in separate fault blocks.*
H_2 storage in gas/condensate prospects						
Ahuroa	Tariki	Gas/cond	5	N/A	1.4 (g)	Reserves data from natural gas storage (FirstGas).
Tariki	Tariki	Gas/cond	17.9	N/A	4.8 (g)	
H_2 storage in oil prospects ± gas						
Tui area	Farewell	Oil	N/A	62.6	3.7 m (o)	Combined reserves data for 3 fields (Tui-Amokura-Pateke); est. 1–2 TWh H_2 storage each.
Maari	Moki	Oil, minor gas	16.1	80.9	3.1 (g + o)	Combined field reserves data for Maari and Manaia with separate estimations for equivalent H_2 storage based on legacy reserves estimates.
Maari	Mangahewa	Gas cap oil leg			2.9 (g + o)	
Manaia	Mangahewa	Oil, minor gas			1.2 (g + o)	
Kaimiro/ Ngatoro	Mount Messenger	Oil, minor gas	18.6	16	5.6 (g + o)	Several small pools with combined reserves data; Kaimiro and Ngatoro represent largest pools.
Cheal/ Cheal E	Urenui & MM	Oil and gas	2.8	8.9	1.1 (g + o)	
H_2 storage in undeveloped sites						
Karewa	Mangaa	Non-com gas	(43.1)	ND	11.6 (g)	Contingent gas reserves from MBIE [84].
Kapuni	Moki	Aquifer	(14.6)	ND	3.9	Unrisked reserves from operator estimates.

for oil and some injectivity and containment parameters.

Once parameters for UHS are better understood and parameter weightings have been revised to reflect this, bias in the decision-making process is expected to reduce, and we suggest that the matrix approach could provide the user with a robust method of ranking multiple sites. A paired comparison matrix [35] may be applicable in future prospectivity analysis to further reduce potential biases of an expert panel, although that process also relies on expert opinion. Notably, there remains significant uncertainty with oil reservoirs, particularly relating to seal competence (for H_2), contamination issues (e.g., potential for methane production), and high residual fluids (see section 6.3). Pending further research, this could effectively disqualify these reservoirs as potential UHS sites. Furthermore, it is recommended that deep aquifer options, in addition to depleted reservoirs, need to be explored further once UHS technology in porous media has been proven. Given their specific requirements and profiles, it is suggested that different matrix parameters and criteria might be applicable for the three storage classes (i.e., gas, oil, and aquifer), and that future prospectivity analysis could result in three separate ranking profiles.

6.2. Summary of outcomes

We have assessed and ranked potential subsurface reservoirs in A-NZ for hydrogen storage based on publicly accessible data and geological interpretations, criteria-driven processes, and current understanding of the technical requirements for UHS. We suggest that storage sites in A-NZ should comprise a volume that is suitable for the size of the market (~0.5–10 TWh working gas), be deep enough to ensure sufficient H_2 densities and to prevent excessive production issues (>1 km), and have adequate reservoir quality for injectivity/withdrawal (average permeability >5 mD). Site-screening criteria that disqualified the largest number of potential UHS sites was minimum size, but this could be revised to a lower value if a storage development project was proven economic at a smaller scale. Once site-screening conditions have been satisfied, the most important parameters for suitable storage sites are thought to be related to H_2 containment and data availability/quality. However, the matrix ranking of sites is highly sensitive to weightings assigned to different parameters, and further work is required to determine the relative importance of different factors for UHS (see section 6.3).

Depleted hydrocarbon reservoirs are considered to represent the best options for developing commercial UHS projects, with depleted gas (or gas cap) reservoirs favoured over oil reservoirs, and Paleogene reservoirs favoured over younger reservoirs. Notably, some of the Miocene sites have top reservoir depths between 1 and 1.5 km and their inclusion as potential UHS sites is dependent upon the minimum depth criterion (>1 km). Some of these sites would be eliminated if the minimum depth was revised to 1.5 km, making it consistent with the recommendation of Hassanpouryouzband et al. [87] to maximise H_2 storage potential. Relatively low ranking of the single deep aquifer option suggests that

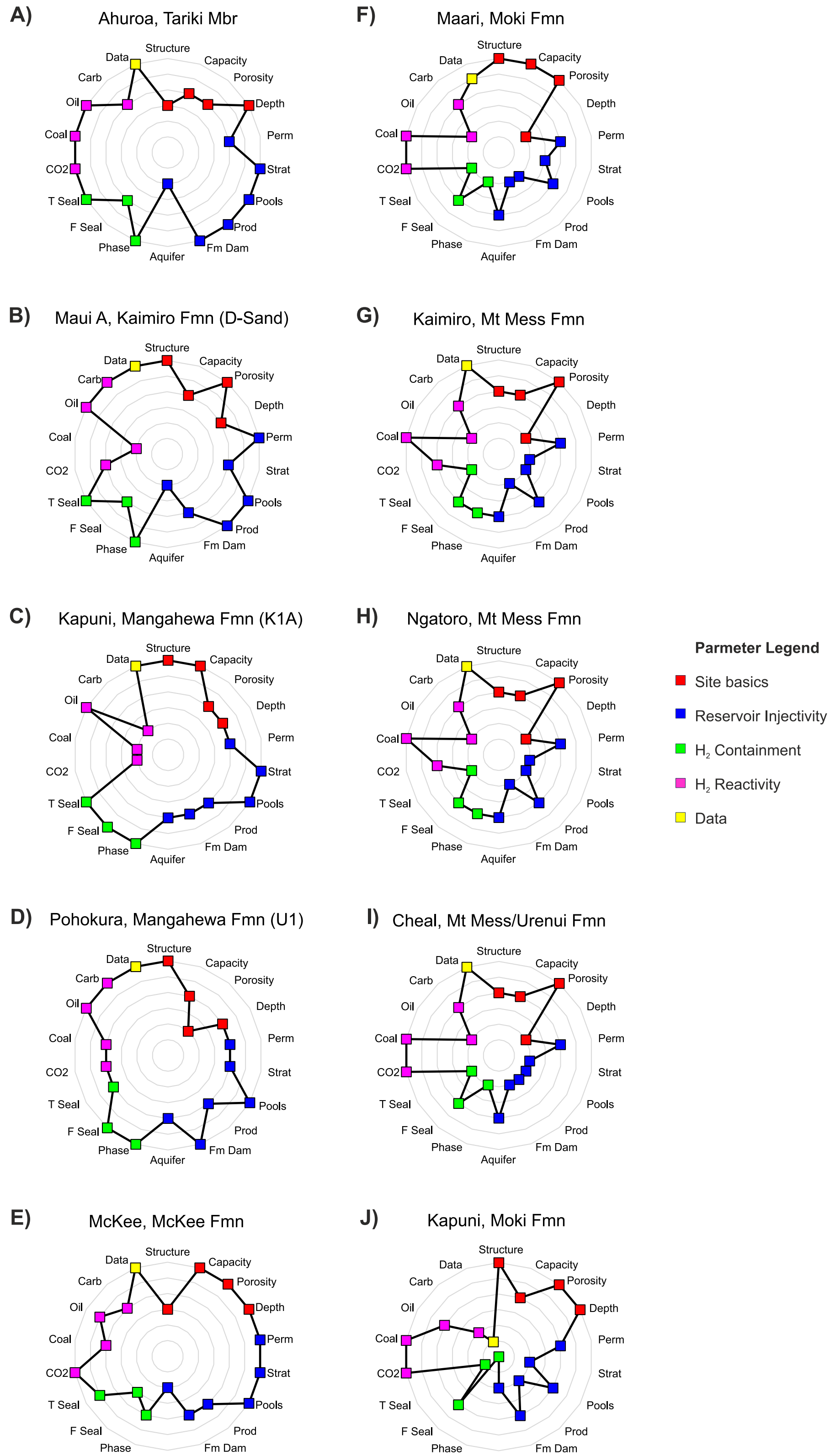


Fig. 6. Spider plots comparing parameter values used in the decision matrix approach to site selection. **A-E)** top five sites, deeper Paleogene reservoirs; **F-J)** bottom five sites, shallow Miocene reservoirs. Values from least favourable for UHS (0 at centre of plots) to most favourable (3 at outside edge of plots). Refer to Table 3 for parameter details and criteria.

this type of play is not advisable in the short-term, and aquifer sites will inevitably require significant technical work programmes prior to consideration.

Results from our prospectivity analysis are sensitive to capacity estimates, with reasonable estimates determined from recoverable reserves data and/or an evaluation of publicly available legacy data. Estimated H_2 storage capacity and a summary of input data used for qualifying sites is shown in Table 6, with higher uncertainties associated with capacity estimates derived from oil reservoirs, undeveloped sites, or combined fields. The maximum storage for Ahuroa (Ahuroa, Tariki) plus Maui A (Maui A, Kaimiro), which represent the top two candidates for demonstrating technical suitability of UHS in Taranaki, is 23 TWh H_2 (supplementary data file 2, Table 6). However, capacity estimates used in the current study assume total H_2 storage (i.e., working gas + cushion gas). Since the cushion gas does not participate in injection/withdrawal cycles it needs to be excluded from the more detailed site characterisation work. The amount of cushion gas will be site-specific and may vary from ~20% to 80% of the total gas storage volume. It will also be dependent on gas composition. Assuming a 50% cushion gas requirement, total estimated H_2 storage capacity across the top two sites exceeds the predicted 2050 domestic demand of ~5 TWh H_2 storage (refer section 3.1).

It has been pointed out by several authors that a conflict of interest may arise for sites with potential for underground storage of natural gas, H_2, and/or CO_2 [21,99]. In the case of A-NZ, the Ahuroa Field is currently being used for natural gas storage and, perhaps unsurprisingly, it also has favourable geological characteristics for UHS (Tables 2 and 4). While a change of use from UGS to UHS would need to make commercial sense to those with a stake in the field, it would conform with the government directive to achieve a net-zero carbon economy by 2050 [73]. Some other storage sites in A-NZ are very large (e.g., Maui A, Mangahewa; Kapuni, K3E Mangahewa), and much larger than would be required for seasonal UHS. As such, it might be more appropriate for these very large sites to be used for CCS or, if reservoirs are compartmentalised, for simultaneous use with both H_2 and CO_2 storage. These operational issues (including potential gas leakage, contamination, and well placement) would need to be resolved as part of site characterisation work.

The current study has only considered the technical suitability of a site for UHS, yet economic, sociocultural, and regulatory factors can make a site unsuitable for development. Conversion of current infrastructure for hydrogen gas would be significant, and additionally, in A-NZ, the pore space rights and ownership, access and permission would need to be carefully assessed and discussed with respect to the indigenous population. Alongside improving our technical understanding of UHS systems, criteria must therefore be developed to evaluate regulatory, political, socio-economic, and environmental characteristics.

6.3. Research directions

Previous work has shown that while there is significant experience with UGS and CCS technology, there is limited understanding of the requirements for UHS. The specificity of H_2 requires significant research and testing before UHS technology is implemented on a commercial scale [21]. This is also highlighted by our study, with both approaches to prospectivity analysis dependent on, and restricted by, the current knowledge base. Criteria used in the current work will need to be revised in light of additional research into H_2 behaviour, in particular how it affects the seal and its potential reactivity with native pore fluid and mineral phases. Ultimately this will lead to a revision of applied criteria and weightings, thereby reducing risk in the selection process and providing the most technically suitable sites for UHS technology.

Some of the key uncertainties in A-NZ site evaluation that need addressing are listed below:

- H_2 reactivity: experimental work to investigate the impact of mineralogy and microbes on H_2 reactivity, losses and contamination. Kapuni, K1A Mangahewa is a potential site to investigate the effect of CO_2, coals and carbonates on UHS. Sulphide abundance in A-NZ rocks is uncertain, but work is recommended to address what amount of sulphide will render a site unsuitable for UHS; sulphates have not been documented in Taranaki but may need to be addressed in other areas.
- H_2 mobility through seal: experimental and modelling work to investigate the sealing requirements for H_2 properties, and the effect of multiple injection and withdrawal cycles where fluctuations in the reservoir pressure may result in induced effects on seal and reservoir. Examples may include seals with facies heterogeneities (e.g., Pohokura), fault-seal (e.g., Kupe), highly faulted structures (e.g., McKee), and/or an oil-only reservoir (e.g., Maui B, Farewell).
- Cushion gas composition: experimental work and dynamic modelling with gas mixtures (e.g., H_2–CH_4, H_2–CO_2) should help us to assess gas storage site conversions, predict the degree of gas mixing (contamination), and make recommendations for cushion gas compositions, which are likely to be site-specific.
- Volume of residual hydrocarbons: experimental and modelling work to investigate the impact of residual hydrocarbons on injectivity/withdrawal. Examples would include fields where significant oil is likely to remain in place following hydrocarbon production, or the uncommercial site Karewa, which has unknown gas reserves that would need displacing or removing prior to hydrogen injection. If results conclude that residual petroleum will be significantly detrimental to hydrogen purity, we suggest that an additional parameter of original hydrocarbon in place should be included in the prospectivity analysis. Time to petroleum depletion may also need to be considered for site prospectivity in other areas.
- Study of aquifer recharge: modelling the displacement of brine relative to reservoir heterogeneity and transport properties of H_2, and how it affects injection and withdrawal rates and scales. Good examples would be Maui A and B, Kaimiro, which have active aquifer charge in high-permeability zones, or Ahuroa, which has recorded aquifer ingress when operating at low pressures.
- Minimum depth criterion: experimental and modelling work to determine the effect of multiple injection and withdrawal cycles on poorly consolidated Miocene reservoirs with depths 1–1.5 km.
- Induced seismicity: an investigation into the historical seismicity of Taranaki with fault mapping and geomechanical studies to predict the degree of induced seismicity likely to result from H_2 injection. Knowledge on managing and derisking seismicity due to fluid injection would be drawn from CCS studies [100,101]. For Taranaki, a regional network of seismometers (GeoNet) provides a unique opportunity for studying historical seismicity, and if UHS is implemented, this could be used with a local seismic array for seismicity monitoring.

The geological feasibility of a site represents just one step in the process of UHS site selection, and there is a need to integrate results from the technical study with social, economic, political, and regulatory criteria before an operator will consider moving towards a pilot project. It is therefore recommended that similar appraisal work is undertaken with the facility operators and local community with any future site assessment also considering storage capacity in relation to economics and location of renewable energy production.

7. Conclusions

Potential hydrogen storage sites have been assessed to determine the most promising locations for demonstrating technical feasibility of underground hydrogen storage (UHS) in Taranaki Basin, Aotearoa New Zealand. Two different methods have been undertaken. The decision tree provides a visual and simplified approach to site evaluation, without the need for input from other sites. As such it can be quickly applied and highlights potential issues that require further investigation. The weighted decision matrix approach uses a criteria-driven workflow and scoring system that provides a more robust method of ranking sites once parameters are better understood. Both methodologies can easily be adapted with revised criteria for regions that have different technical challenges.

We consider that the most important parameters for assessing UHS feasibility are storage capacity, reservoir depth, and parameters that affect injectivity and containment. Provisional recommended criteria for UHS in Taranaki Basin are H_2 capacity (working gas + cushion gas) in the range 1–20 TWh, minimum top reservoir depth of 1 km, and minimum average permeability of 5 mD. Depleted oil and gas reservoirs are considered the best options for demonstrating UHS technology given their established datasets, proven reservoirs, seals and traps, and existing infrastructure. Depleted gas reservoirs (and gas caps overlying oil legs) are favoured over depleted oil reservoirs on the premise that caprocks proven to contain natural gas are more likely to contain H_2 than caprocks for liquid hydrocarbons.

Individual UHS sites in Taranaki Basin offer a wide range of H_2 storage capacities ($\ll$1 TWh to $\gg$20 TWh). Based on our assessment, we suggest that commercial development of one or two depleted fields (or compartments thereof) would provide sufficient storage capacity for UHS development in A-NZ by 2050 (>5 TWh). Highest ranking sites are all from Paleogene reservoirs, which are typically fine-to coarse-grained, quartzo-feldspathic sandstones that were deposited during the rift to passive margin and earliest contractional stages of basin history. The lowest ranking sites are mostly from the finer grained, labile, clay-rich, small and typically compartmentalised Miocene reservoirs that were deposited in an active margin and are relatively poorly lithified.

Prospectivity analysis has highlighted several parameters that need to be better understood before UHS sites can be identified. Our studies suggest that the main risks requiring further research include: a) potential losses and contamination of stored gas associated with H_2 reactivity (with CO_2, coal etc.), and b) potential leakage of H_2 through seals due to the higher diffusivity, lower viscosity and lower density of hydrogen compared to methane. We aim to select sites for characterisation that can address some of these outstanding risks, with subsequent revision of parameters, weightings, and criteria to reflect hydrogen storage requirements. Ultimately this work will help in developing a consistent methodology for UHS prospectivity analysis to ensure safe, secure, and economic deployment of hydrogen storage that can be applied globally.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2024.05.098.

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