Transport and Storage Options for Future Fuels: Multi-stage planning

Milestone 7

December 20, 2023

Project number: RP1.1-02B

Transport and Storage Options for Future Fuels

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Business Cooperative Research Centres Program

This work is funded by the Future Fuels CRC, supported through the Australian Government's Cooperative Research Centres Program. We gratefully acknowledge the cash and in-kind support from all our research, government and industry participants.

IMPORTANT DISCLAIMER

ACKNOWLEDGEMENT

This work is funded by the Future Fuels CRC, supported through the Australian Governments' Cooperative Research Centres Program. The cash and in-kind support from the industry participants is gratefully acknowledged.

PROJECT INFORMATION	
Project number	RP1.1-02B
Project title	Transport and Storage Options for Future Fuels
Research Program	RP1
Milestone Report Number	7: Extension to real options analysis. Final milestone report and case studies
Description	Report presents illustrative modelling of multi-stage integrated planning of electricity and hydrogen transmission and storage infrastructure for producing green hydrogen.
Research Provider	University of Melbourne
Project Leader and Team	Prof Pierluigi Mancarella (Lead), University of Melbourne Dr. Sleiman Mhanna, University of Melbourne Isam Saedi, University of Melbourne
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Related Commonwealth Schedule	Output Milestones 1.2 and 1.3.
Project start/completion date	July 2021/June 2023
IP Status	Confidential
Approved by	Dennis Van Puyvelde
Date of approval	13th December 2023

EXECUTIVE SUMMARY

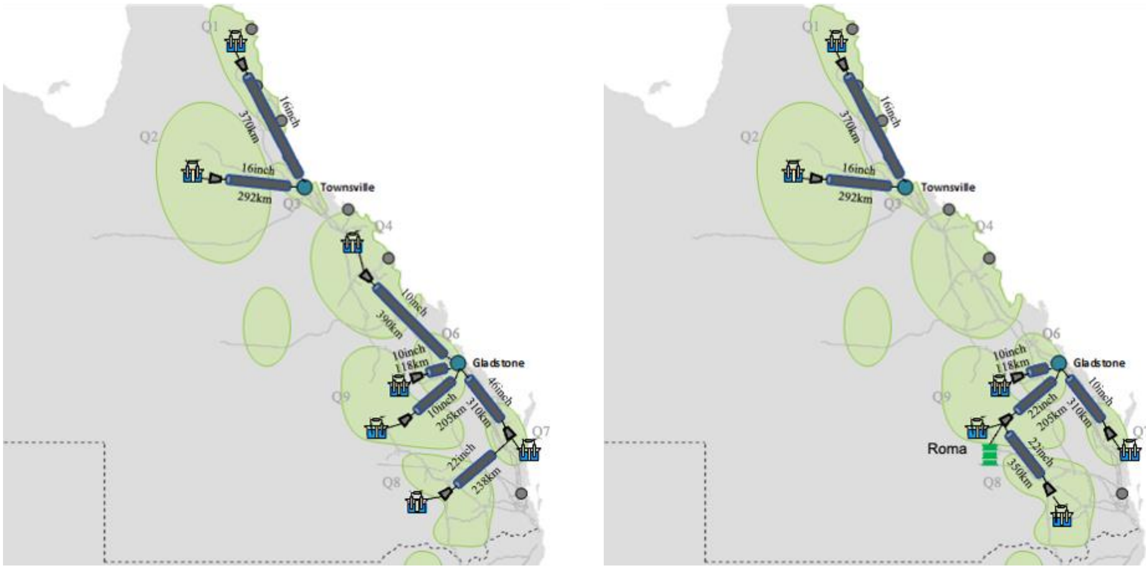
As the widespread adoption of hydrogen evokes the key question of which of the two options, transporting "green" molecules, or transporting "green" electricity, is the most cost-effective one, this report introduces a first-of-its-kind mathematical optimisation framework for finding the optimal greenfield *multi-stage* integrated planning of electricity and hydrogen transmission and storage infrastructure for producing *green* hydrogen. The capabilities of this model are demonstrated on a two-part proof-of-concept case study that considers all the renewable energy zones (REZ) stipulated in the 2022 *Integrated System Plan* (ISP) published by the Australian Energy Market Operator (AEMO) and connects them with provisional corridors to the hydrogen export ports whose demands are specified in the same ISP under the *Hydrogen Superpower* scenario for years (stages) 2027, 2032, and 2037. The case study also considers candidate underground hydrogen storage (UHS) facilities in the form of depleted gas fields, which can offer medium and long duration storage that can play a crucial role in buffering the variability of renewable energy sources (RES).

In contrast to most existing works, the developed optimisation framework not only considers all relevant infrastructure technologies such as high voltage direct current (HVDC), high voltage alternating current (HVAC), reactive power plants, battery energy storage systems (BESS), and hydrogen pipelines and compressors, but also incorporates all the essential nonlinearities that directly influence the optimal infrastructure investment decision, such as voltage drops due to impedances in HVAC and HVDC transmission lines, losses in HVDC converter stations, reactive power flow, pressure drops in pipelines, linepack, and nonlinear withdrawal/injection rates of UHS systems. The model adopts a relatively high temporal resolution that aligns with the resolution of the forecast VRE traces in AEMO's 2022 ISP to fully capture the variability of RES, the ability of storage technologies in buffering this variability, and their impact on the optimal investment decision. Moreover, in contrast to single-stage planning, multi-stage planning is an incremental expansion approach characterised by a long-sighted outlook that enables future incremental expansion at *cheaper costs* by making forward-thinking investments that can capture the gradual growth in hydrogen demand and VRE capacity, as well as lead time of construction of the assets. The multi-stage model also provides insights into the *option value* of investing early in larger pipelines in anticipation for high RES variability and/or uncertainty in the amount of installed RES capacity in subsequent years.

Under the specific cost assumptions, technical assumptions, corridor lengths, energy volumes, storage requirements, VRE forecasts, specific type and variability of the demand, and hydrogen export demand forecasts in this case study, in addition to the very nature of greenfield expansion planning in which no interaction with existing electricity and natural gas infrastructure is considered, the findings suggest that:

- Compared to an incremental but *myopic* planning approach that incrementally finds a solution by solving a single-stage planning problem in each year (stage) and locking in investments found in early stages, the multi-stage model, which is a single optimisation problem that considers all the stages simultaneously, is demonstrated to enable future incremental expansion at *cheaper costs* by making forward-thinking investments that consider a long-sighted outlook over the evolution of the demand and RES capacity. Under the considered case study, the solution found by the multi-stage planning model is AUD 4.75 B (~ 13%) cheaper than the solution found by an incremental but myopic planning approach (i.e., solving a single-stage planning problem in each year).

- The multi-stage model can capture the *option value* of installing larger pipelines in early years of the planning horizon in anticipation for uncertainty in RES capacity and location of investment in subsequent years and the high RES operational variability that may call for larger storage requirements. This is witnessed predominantly in South Australia when considering stages (years) 2027, 2032, and 2037. It is this flexibility derived from pre-defining a cost-effective action of investing early in larger pipelines that provides investors with the *option value*.
- Under steady-state throughputs (where no storage is required) hydrogen pipelines are more cost effective than their electricity counterparts across all the capacities and distances considered in this report. More details on this analysis can be found in the Milestone 6 report.
- Pipelines are once again deemed as the optimal transport infrastructure across all the considered planning stages (2027, 2032, and 2037). This is predominantly due to the high variability of RES, which requires in some cases more than 8 hours of storage to buffer this variability. Linepack storage is of utmost importance in this case as the RES supply is variable and the hydrogen export demand is assumed constant in each year (stage) state (QLD and SA) but distributed, not necessarily equally, over the envisaged hydrogen export ports in each state. These results align with the findings in the single corridor case study in the Milestone 6 report.
- Investing in UHS in the form of depleted gas fields in specific locations in Australia can significantly *decrease* the total investment costs of transport and storage infrastructure. This is because the marginal cost of storage in the considered UHS facilities is much lower than that of a pipeline, and as a result the storage capacity gained from installing the UHS can displace more expensive storage (linepack) in adjacent pipelines, thereby resulting in the downsizing of these pipelines. The optimal greenfield integrated multi-stage infrastructure designs for the two studies, one excluding UHS and one including UHS, considering REZ and hydrogen export demands from AEMO's 2022 ISP in stages (years) 2027, 2032, and 2037 are shown in Figure 1 a) and b) respectively. Figure 1 focusses on Queensland as UHS is only adopted for that state in this study. Being able to access UHS changes the pipeline requirements between the two cases, as illustrated.



a) Without UHS.

b) With UHS.

Figure 1: Optimal greenfield integrated multi-stage infrastructure and storage designs for the two cases: a) without UHS, and b) with UHS, in year (stage) 2037. Notice the difference in pipeline diameters in Queensland between the two cases.

This assessment does not consider electricity as demand – it only considers green hydrogen as export demand, with no assumptions of what this green hydrogen is used for. It should also be emphasised that the assessment and case studies in this report are classified under *greenfield* integrated expansion planning that optimises *newly* built electrolysis, transmission, and storage infrastructure network in *isolation* from existing infrastructure, for a specified constant (but increasing each year) green hydrogen export demand distributed (not necessarily equally) over the envisaged hydrogen export ports in each state.[1] In other words, this greenfield assessment does not consider the interactions between this newly built infrastructure network and the existing electricity transmission infrastructure such as the one in the National Electricity Market (NEM). The findings in this report might thus change if these interactions are considered as other elements in the electricity system (e.g., flexible generation, BESS, pumped hydro energy storage (PHES), and transmission network) could provide flexibility to buffer variability from RES, thereby potentially displacing additional storage requirements in pipelines. The assessment also neglects water requirements for electrolysers due to lack of data, which might also alter the findings when included. All the cost assumptions in this report are for year *2023*. Their NPV also considers 2023 as reference year. In addition to pipelines, other viable options for hydrogen transportation include tanker trucks and tube trailers. These options are discussed in more detail in the *Milestone 3: Literature review* of the project.

The modelling of UHS in this project, together with the electricity network modelling developed in “RP1.1-02A: Regional case studies on multi-energy system integration”, will pave for the way for project “*RP1.1-07: Integrated electricity-hydrogen: future system and market interactions under different storage considerations*” which commenced in October 2023.

Finally, the findings in this report should be considered solely for illustration and demonstration purposes rather than real guidelines for energy infrastructure planners and stakeholders, for which specific studies based on agreed input data and assumptions should be performed.

[1] The total hydrogen demand in each state is assumed constant – converted from Mt/year to m^3/s. However, instead of dividing this hydrogen demand equally across the export ports stipulated in AEMO’s 2022 ISP for each state, the model is setup to choose how to *optimally* distribute (i.e., with potentially varying proportions) this hydrogen demand across these ports.

Table of Contents

FIGURES

Tables

ACRONYMS

AACE	Association for Advancement of Cost Engineering
AEMO	Australia Energy Market Operator
AUD	Australian Dollar
BESS	Battery energy storage system/systems
CapEx	Capital expenditure
EVR	Erosional velocity ratio
H_2	Hydrogen gas
HHV	Higher heating value
HSC	Hydrogen supply chain
HVAC	High voltage alternating current
HVDC	High voltage direct current
ISP	Integrated system plan
LCC	Line commutated converters
LCOE	Levelised cost of energy
LHV	Lower heating value
MMC	Modular multilevel converters
NEM	National Electricity Market
NG	Natural gas
NPV	Net present value
NSW	New South Wales
OHL	Overhead line
OpEx	Operating expenditure
PEM	Proton exchange membrane
PHES	Pumped hydro energy storage
PtG	Power-to-gas
PV	Photovoltaic
QLD	Queensland
RES	Renewable energy sources
REZ	Renewable energy zones
SA	South Australia
SMYS	Specified minimum yield stress
SVC	Static VAr compensator

UHS	Underground hydrogen storage
USD	United State Dollar
VIC	Victoria
VRE	Variable renewable energy
VSC	Voltage-source converters

1. INTRODUCTION

Most energy system planners in countries with an abundance of renewable energy sources (RES), including the Australian Energy Market Operator (AEMO), are now considering in their transport infrastructure planning scenarios the potential deployment of large-scale green hydrogen production (through electrolysis) for export of green fuels and decarbonisation of heavy industry, which will lead to a massive increase in demand associated with such developments and thereby create major interactions between electricity and future green hydrogen systems. Depending on the evolution of hydrogen technology, its industry uptake, and the State and Federal Governments' support schemes and strategies, the impact on the planning of the electricity system can be substantial. AEMO's *Hydrogen Superpower* scenario in the 2022 *Integrated System Plan* (ISP) (Australian Energy Market Operator, 2022a) envisions that by 2050 the National Electricity Market (NEM) would need approximately 269 GW of wind and approximately 278 GW of solar – 34 times its current capacity of variable renewable energy (VRE) – to export green hydrogen, and support decarbonisation of heavy industry (e.g., green steel making), gas-fired generation (through hydrogen turbines), and end-use (by progressively switching households with natural gas (NG) connections to hydrogen-NG blend). This monumental scale of development will require the NEM to deliver eight times its current energy delivery by 2050.

Hydrogen can be produced from renewable energy through a power-to-gas (PtG) process (Hosseini & Wahid, 2016),[2] and transported and stored in liquid or compressed forms, or as a chemical compound such as ammonia (Lamb et al., 2019; Lambert, 2020; McKinsey & Company, 2021; Zhang et al., 2016). This imminent advent of large-scale green hydrogen production raises the central question of which of the two options, transporting green hydrogen from distributed hydrogen producers co-located at the renewable energy zones (REZ), or transporting green electricity from REZ to a central hydrogen production hub, is the most cost-effective one across different distances, for different renewable energy portfolios, and subject to local availability of water and multi-vector storage options. The role of hydrogen as a way to transport renewable energy over long distances was identified in a 2018 report from IRENA (IRENA, 2018), in light of the emissions reduction targets outlined in the Paris Agreement. IRENA's roadmap for the energy transition towards low-carbon emissions is centred on key green hydrogen production technologies as the main drivers, particularly proton exchange membrane (PEM) electrolysers and fuel cells, which are approaching technical maturity and economies of scale. According to a recent study by CSIRO, the cost of PEM hydrogen electrolysers is projected to drop to nearly a third of its current costs by 2035 (Graham et al., 2022).

Large-scale renewable energy hubs connected to hydrogen production hubs can unlock substantial economies of scale predicated on building a *cost-effective* VRE transport infrastructure that will address the challenging questions of (i) whether VRE hubs and electrolysers should be co-located, (ii) whether to transport[3] VRE as molecules in hydrogen pipelines or as electricity in electricity transmission lines, and (iii) the drivers and conditions that favour one investment option over another. Answering the above questions is a massive undertaking that requires new optimisation-based models for the planning of integrated

[2] The terms "PtG" and "electrolyser" are used interchangeably in this report.
[3] The terms "transport" and "transmission" are used interchangeably in this report.

electricity and hydrogen system (IEHS) to assess costs and benefits of different investment options.

As many of the challenges identified here are relatively new, existing knowledge and modelling tools are inadequate for performing such a large-scale *optimal* integrated infrastructure design exercise. In particular, existing state-of-the-art literature is either limited in scope to hydrogen supply chain (HSC) only (De-León Almaraz et al., 2014; Li et al., 2019; Moreno-Benito et al., 2017; Weber & Papageorgiou, 2018), i.e., disregarding electricity infrastructure options, or is limited in the variety of considered infrastructure technologies (DeSantis et al., 2021; Samsatli & Samsatli, 2018; Singlitico et al., 2021; Welder et al., 2019). Considering all the relevant transport and storage technologies in an integrated framework can unlock superior design solutions. This is especially true when considering the specific features associated with RES, and in particular when they are clustered in large-scale renewable energy hubs where wind and solar farms may be located far from the location of hydrogen utilisation.

Other essential aspects that are ignored in the literature include voltage drops due to impedances in transmission lines, pressure drops in pipelines, linepack,[4] compressor sizing, water availability for electrolysers, reactive power compensation, and nonlinear withdrawal/injection rates of underground hydrogen storage (UHS) systems, all of which play an important role in determining the optimal infrastructure investment decision. The modelling of the linepack is instrumental in quantifying the VRE storage capacity of the hydrogen pipeline network, which can in turn influence the sizing of hydrogen pipelines and compressors. In fact, most (if not all) existing works use *steady-state* gas flow models, which are generally inadequate in gas transmission networks where hydrogen injections from VRE introduce time-varying accumulation rates. More importantly, with only a few exceptions (Samsatli & Samsatli, 2018; Welder et al., 2019), the majority of existing research ((DeSantis et al., 2021; Moreno-Benito et al., 2017; Singlitico et al., 2021; Weber & Papageorgiou, 2018), (Rhodes et al., 2021)), only examine transport options between two nodes (point-to-point transmission), as opposed to over a network with a general topology (which may include loops and parallel corridors). At first glance, it might appear that the single-corridor analysis prevalent in existing literature can be applied to a network by treating each corridor independently, nonetheless such an approach quickly becomes infeasible even for a simple network with one variable renewable energy hub connected to two variable hydrogen demand points via two corridors with different lengths.

Furthermore, as demand and supply generally increase across the years, planning undertakings are often underpinned by *multiple* development stages. Multi-stage planning is also desired for capturing the lead investment time of assets, which is the period of time from conceptualisation to construction, all the way to commissioning. Nonetheless, in the context of integrated planning of electricity and hydrogen transport and storage infrastructure, most if not all existing works only focus on *single-stage* planning.

Against this backdrop, this report introduces a novel mathematical optimisation model that can find the optimal *greenfield* multi-stage integrated planning of transport and storage infrastructure for transporting large-scale VRE to hydrogen export demand locations in either electricity lines and/or hydrogen pipelines. Specifically, the model not only considers all relevant infrastructure technologies such as HVDC, HVAC, reactive power plants, battery

[4] The linepack is the amount of pressurised gas stored in a pipeline network.

energy storage systems (BESS), and hydrogen pipelines and compressors, but also incorporates all the essential nonlinearities that directly influence the optimal infrastructure investment decision, such as voltage drops due to impedances in HVAC and HVDC transmission lines, losses in HVDC converter stations, reactive power flow, pressure drops in pipelines, linepack, and nonlinear withdrawal/injection rates of UHS systems. Additionally, the model adopts a relatively high temporal resolution to suitably capture the variability of RES and its impact on the optimal investment decision. In contrast to single-stage approaches, the developed optimisation-based modelling in this project supports *multi-stage* planning which is an incremental expansion approach characterised by a long-sighted outlook that enables future incremental expansion at *cheaper costs* by making forward-thinking investments that can capture the gradual growth in hydrogen demand and VRE capacity, in addition to lead time of construction of the assets. The multi-stage model also provides insights into the *option value* of investing early in larger pipelines in anticipation for high RES variability and/or uncertainty in the amount of installed RES capacity in subsequent years.

The developed optimal *greenfield* multi-stage integrated infrastructure planning model is demonstrated on a two-part case study that considers all the REZ stipulated in AEMO's 2022 ISP (Australian Energy Market Operator, 2022a) and connects them with provisional corridors to the hydrogen export ports whose demands are specified in AEMO's 2022 ISP under the *Hydrogen Superpower* scenario. The case study is conducted with VRE traces and hydrogen export demand for years (stages) 2027, 2032, and 2037. As the widespread adoption of hydrogen in Australia may require medium and long duration storage, beyond typical storage capacities (linepack) of pipelines, to buffer the fluctuations in supply and demand (Amirthan & Perera, 2022a), the second part of the case study incorporates candidate UHS facilities in the form of depleted gas fields, as identified in FF CRC project "RP1.1-04: Underground storage of hydrogen: mapping out the options for Australia" (Ennis-King et al., 2021), as an initial test bed. Depleted gas fields are identified in project RP1.1-04 as a viable option for hydrogen storage in Australia as they can provide safe large-scale storage at a lower cost compared to saline aquifers (Amirthan & Perera, 2022b).

This milestone report extends the single-stage modelling in the Milestone 6 report to a multi-stage planning one that considers *multiple* development stages. Similar to the Milestone 6 report, all the cost assumptions in this report are for year *2023*. These are then projected to the respective years (epochs) under study (e.g., 2027, 2032, and 2037) using a constant inflation rate of 2.5% per year. Their NPV also considers 2023 as reference year.

2. MODELLING

A prototype *greenfield* integrated VRE transport and storage infrastructure planning model is shown in Figure 2, where three different technologies, namely, (high-pressure) hydrogen pipeline links (including carbon steel pipelines and inlet compression stations), HVAC transmission links (including overhead lines (OHL), transformer substations, and reactive power compensation), HVDC links (including OHL and converter stations) are considered as transport infrastructure options. Detailed mathematical modelling can be found in the Milestone 3 report and in (Mhanna et al., 2022). Storage technologies (in addition to pipeline storage) consist of UHS and BESS.

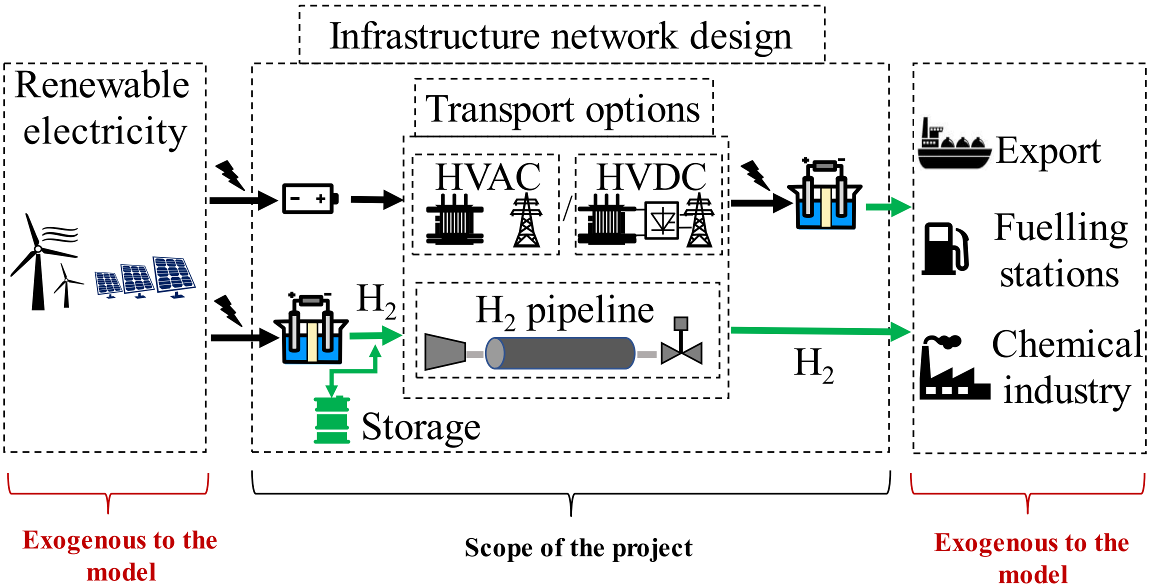


Figure 2: Illustration of a prototype integrated VRE transport and storage infrastructure model where the energy from multiple VRE hubs can be transported to a hydrogen demand hub using electricity lines and/or hydrogen pipelines over a network with arbitrary topology.

Typical injection and withdrawal rates as functions of storage levels for underground natural gas (NG) storage facilities are shown in Figure 3 (see (Pozo et al., 2023) for more details). Similar behaviour is assumed for UHS in this report.[5]

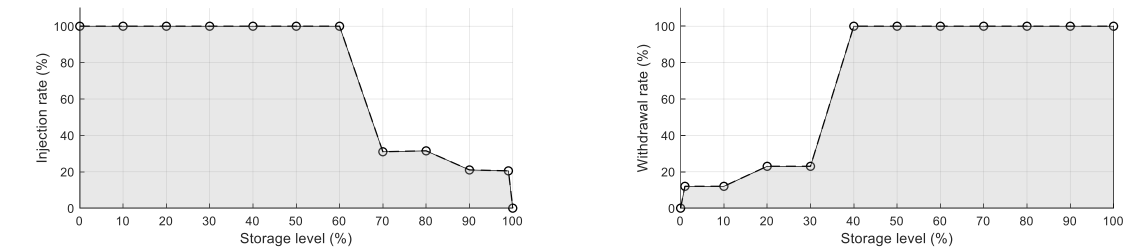


Figure 3: Typical withdrawal (left) and injection (right) rates as a function of gas storage level of underground NG storage facilities.

The following assumptions are adopted in the above integrated planning model:

[5] The injection and withdrawal rates in Figure 3 are intended to serve only as proof of concept. Such behaviour can change with different sizes and types of UHS and would thus require stakeholder consensus for targeted applications.

- Project life is 20 years from the time it is installed.
- Three planning stages (years)are considered, namely, 2027, 2032, and 2037.
- The optimisation model considers 4 representative weeks, one for each season, that are carefully selected to reflect the seasonable variability of RES. This reduction is necessary to ensure that the computational requirements fall within the current capabilities of current state-of-the-art industrial optimisation solvers such as Gurobi (Gurobi Optimization, 2018).[6]
- A 30-minute temporal resolution is considered, which aligns with the resolution of the VRE forecasts in AEMO's 2022 ISP. A less granular temporal resolution may not capture the variability of RES and linepack[7] to sufficient accuracy, which can in turn be detrimental to the quality of the computed solutions.
- Inflation rate is 2.5% per year.
- Lead time of each asset is 5 years.
- Discount rate is 6% per year.

In contrast to existing works, the above model is not limited to point-to-point instances (i.e., single corridor) but can find the optimal integrated transport and storage infrastructure design over a *network* with arbitrary topology and multiple variable supplies and demands. In a nutshell, the capabilities of the modelling so far include:

- Optimal investment planning of large-scale integrated electricity and hydrogen transmission and storage infrastructure networks, including UHS and BESS,
- Multiple variable supplies and demands,
- Multiple stages (years),
- Essential physics such as
    - Conversion and transportation losses,
    - Linepack (to manage RES variability),
    - Nonlinear injection and withdrawal rates of UHS.

The mathematical modelling in this project leverages advanced optimisation and computational methods that are designed with maximum flexibility in mind. In other words, the model is fully parametrised to rapidly incorporate and explore stakeholder insights**.**

[6] Even after this careful reduction in problem size, a typical multi-stage integrated planning problem in this report can take one week on average to solve.
[7] The *linepack* is the amount of pressurised gas stored in a pipeline network.

3. METHODOLGY

Mathematically, the objective of the multi-stage integrated infrastructure and storage planning problem is to minimise the total *net present value* (NPV) of both investment and operational costs for a predetermined hydrogen demand over the considered optimisation planning horizon and the considered stages (years) $s \in S$ as

$$\text{minimise} \quad \sum_{s\in S} NPV(CapEx_s^{\text{ptg}} + CapEx_s^{\text{pipe}} + CapEx_s^{\text{uhs}} + CapEx_s^{\text{hvac}} + CapEx_s^{\text{hvdc}} + CapEx_s^{\text{bess}} + OpEx_s^{\text{ptg}} + OpEx_s^{\text{pipe}} + OpEx_s^{\text{uhs}} + OpEx_s^{\text{hvac}} + OpEx_s^{\text{hvdc}} + OpEx_s^{\text{bess}}) \quad (1a)$$

$$\begin{aligned}
\text{subject to} \quad & \text{H}_2 \text{ demand}, \quad s \in S & (1b)\\
& \text{Operational constraints}, \quad s \in S & (1c)\\
& \text{Physics of flow of electricity}, \quad s \in S & (1d)\\
& \text{Physics of flow of H}_2 \text{ (Quasi-dynamic gas flow model)}, \quad s \in S & (1e)\\
& \text{UHS constraints (nonlinear injection/withdrawal rates)}, \quad s \in S & (1f)\\
& \text{BESS constraints}, \quad s \in S & (1g)\\
& \text{Coupling constraints (through PtG)}, \quad s \in S & (1h)\\
& \text{Investment constraints (incl., non-anticipativity}^{8}\text{)}. & (1i)
\end{aligned}$$

In contrast, a single-stage planning problem, such as the one developed and explored in the Milestone 6 report, solves the following optimisation problem

$$\text{minimise} \quad NPV(CapEx_s^{\text{ptg}} + CapEx_s^{\text{pipe}} + CapEx_s^{\text{uhs}} + CapEx_s^{\text{hvac}} + CapEx_s^{\text{hvdc}} + CapEx_s^{\text{bess}} + OpEx_s^{\text{ptg}} + OpEx_s^{\text{pipe}} + OpEx_s^{\text{uhs}} + OpEx_s^{\text{hvac}} + OpEx_s^{\text{hvdc}} + OpEx_s^{\text{bess}}) \quad (2a)$$

$$\begin{aligned}
\text{subject to} \quad & \text{H}_2 \text{ demand}, & (2b)\\
& \text{Operational constraints}, & (2c)\\
& \text{Physics of flow of electricity}, & (2d)\\
& \text{Physics of flow of H}_2 \text{ (Quasi-dynamic gas flow model)}, & (2e)\\
& \text{UHS constraints (nonlinear injection/withdrawal rates)}, & (2f)\\
& \text{BESS constraints}, & (2g)\\
& \text{Coupling constraints (through PtG)}, & (2h)
\end{aligned}$$

where s is the considered year.

The multistage optimisation problem in (1), including the objective function in (1a), considers all the years (stages) simultaneously in a *single optimisation problem*, whereas the single-stage problem in (2) does not. This equips the multistage optimisation problem in (1) with the ability to make forward-thinking investments that consider a long-sighted outlook over the evolution of the demand and RES capacity, manifesting in future incremental expansion at *cheaper costs* compared to a myopic approach consisting of solving a single-stage planning problem like the one in Problem (2) in each year and locking in investments found in early stages.

[8] Non-anticipativity constraints ensure that an investment made at a certain stage (year) will be present in subsequent stages.

As a result of incorporating this long-sighted outlook in a single optimisation problem, the multistage optimisation problem in (1) can also capture the *option value* of installing larger pipelines in early years of the planning horizon in anticipation for uncertainty in RES capacity and location of investment in subsequent years and the high RES operational variability that may call for larger storage requirements.

The advantages of solving a multistage problem such as the one in (1) above as opposed to solving the single-stage problem in (2) in each year and locking in investments found in early stages, are demonstrated in Section 4 below.

4. CASE STUDIES

The case study in this section, which is divided into two parts in Section 4.1 and Section 4.2 respectively, is a proof of concept of the capabilities of the developed first-of-its-kind optimisation framework to scale up the analysis to a general network with arbitrary topology, multiple variable supplies and demands, and multiple stages (years). In contrast to single-stage planning, multi-stage planning can capture the gradual growth in hydrogen demand and VRE capacity, in addition to lead time of building the assets. In particular, these capabilities are demonstrated on a case study involving the whole east coast of mainland Australia (excluding Tasmania) with REZ, VRE traces (30-minute resolution), hydrogen demands (assumed constant), and hydrogen export ports from the *Hydrogen Superpower* scenario in AEMO's 2022 ISP (Australian Energy Market Operator, 2022a) for years (stages) 2027, 2032, and 2037. More specifically, the case study considers all the mainland REZ stipulated in AEMO's 2022 ISP and connects them with provisional corridors to hydrogen export ports whose demands are specified in AEMO's 2022 ISP under the *Hydrogen Superpower* scenario for years 2027, 2032, and 2037. The case study also considers candidate UHS facilities in the form of depleted gas fields, as described in (Ennis-King et al., 2021) and (Amirthan & Perera, 2022b). These proposed provisional corridors and candidate UHS facilities are shown in Figure 4. It should be emphasized that the case study in this section is a *greenfield* expansion planning which optimises newly built electrolysis, transmission, and storage infrastructure network in *isolation* from existing infrastructure for a specified constant hydrogen export demand distributed (not necessarily equally) over the envisaged hydrogen export ports in each state.

The forecast hydrogen export demand from the whole NEM in 2027, 2032, and 2037, obtained from the "Inputs assumptions and scenarios workbook" in (Australian Energy Market Operator, 2022a) under the *Hydrogen Superpower*, is shown in Table 1.[9] The total hydrogen demand in each state is assumed constant – converted from Mt/year to m^3/s. However, instead of dividing this hydrogen demand equally across the export ports stipulated in AEMO's 2022 ISP for each state, the model is setup to choose how to optimally distribute (i.e., with potentially varying proportions) this hydrogen demand across these ports. A breakdown of the forecast RES capacity of each REZ in 2027, 2032, and 2037 is shown in Table 2. The hydrogen export demand in Table 1 and the forecast RES capacities in Table 2 (as well as forecast VRE traces) are inputs to the optimisation model.

Table 1: Hydrogen export demand in Mt/year from the whole NEM in 2027, 2032, and 2037 under the ISP's Hydrogen Superpower scenario (Australian Energy Market Operator, 2022b)**.**

	2027	2032	2037
SA	0.09	0.42	1.12
QLD	0.02	0.25	1.41
Total	0.11	0.67	2.53

[9] Forecast hydrogen export demand in 2027, 2032, and 2037 for each state is obtained from http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.

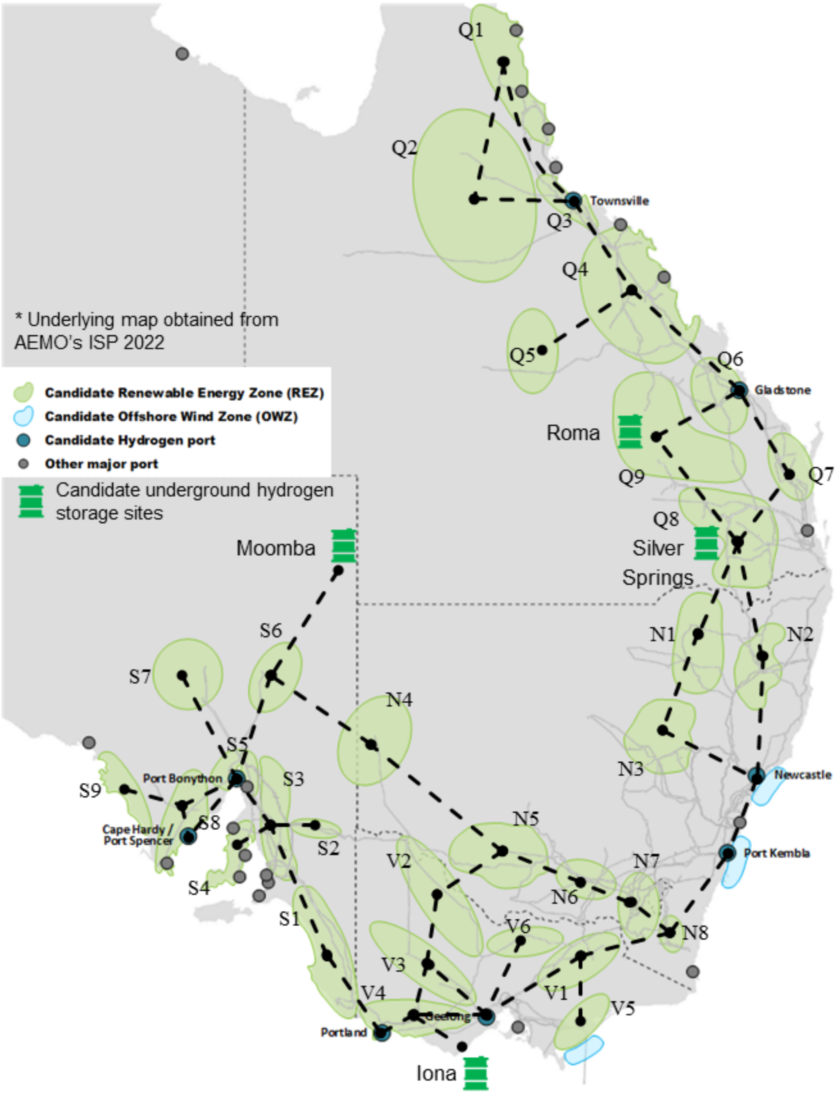


Figure 4: Dashed lines delineating the proposed provisional transmission corridors connecting REZ and hydrogen export ports. The figure also shows the proposed candidate UHS sites (Ennis-King et al., 2021). The underlying map is obtained from AEMO's 2022 ISP (Australian Energy Market Operator, 2022a).

Table 2: Forecast RES capacity (GW) in each considered REZ in 2050 (Australian Energy Market Operator, 2022b)**.**

		Wind generation (GW)			Solar generation (GW)		
State	REZ	2027	2032	2037	2027	2032	2037
QLD	Q1	1.65	2.64	8.81	0.00	0.00	1.10
	Q2	0.79	3.73	4.74	0.24	1.23	2.90
	Q3	0.00	0.00	0.00	0.44	0.44	3.84
	Q4	0.69	1.00	1.85	0.62	0.95	4.11
	Q5	0.09	0.10	0.10	0.07	0.08	0.08
	Q6	1.70	2.57	3.50	1.62	3.25	7.53
	Q7	0.46	0.99	4.79	0.53	2.10	3.68
	Q8	4.80	5.30	11.68	1.83	4.37	8.10
	Q9	0.00	0.00	0.84	0.00	0.18	1.69

		Wind generation (GW)			Solar generation (GW)		
State	REZ	2027	2032	2037	2027	2032	2037
SA	S1	1.24	1.20	3.40	0.14	0.14	0.14
	S2	0.00	0.00	0.00	0.61	1.37	1.67
	S3	2.82	4.26	5.58	0.00	0.00	0.68
	S4	0.12	0.11	1.40	0.00	0.00	0.00
	S5	0.42	0.42	0.42	0.30	0.86	3.20
	S6	0.06	2.40	7.84	0.04	2.00	6.50
	S7	0.00	0.00	0.00	0.50	0.57	0.64
	S8	0.38	0.93	0.86	0.00	0.00	0.00
	S9	0.00	0.00	0.00	0.00	0.00	0.00

Potential UHS facilities in Australia along with their equivalent envisaged UHS capacities, injection and withdrawal rates, and costs are shown in Table 3. Assumptions on input technical parameters and costs of hydrogen pipeline links (including compressors), HVAC links, HVDC links, electrolysers, and BESS can be found in Appendix A: Cost and Parameter Assumptions. These assumptions are largely based on the assumptions in (i) pipelines and compressors ((GPA Engineering, 2022)), (ii) for BESS ((Graham et al., 2022)), and (iii) AEMO's transmission cost database in the 2022 ISP (Australian Energy Market Operator, 2022a) for HVDC links and HVAC links. The analysis is this section uses the same HVAC and HVDC options described in the REZ augmentation options and the flow path augmentation options in AEMO's 2022 ISP (Australian Energy Market Operator, 2022a).

It should be emphasised that the cost and parameter assumptions in Appendix A: Cost and Parameter Assumptions are for the sole purpose of demonstrating the novel integrated modelling in this report. Therefore, in the context of these specific costs and parameter assumptions, the findings in this report should be considered solely for illustration and demonstration purposes rather than real guidelines for energy infrastructure planners and stakeholders, for which specific studies based on agreed input data and assumptions should be performed.

Table 3: Potential UHS facilities in Australia along with their equivalent UHS capacity, injection and withdrawal rates, and costs (Ennis-King et al., 2021).[10]

Storage facility	Basin	Injection (TJ/d)	Withdrawal (TJ/d)	Capacity (PJ)	Cost (USD/kg)	OpEx (% of CapEx)	Efficiency (%)
Silver Springs	Bowen-Surat (QLD)	4	5	12	1.73	2	98
Roma	Bowen-Surat (QLD)	29	16	15	1.73	2	98
Moomba	Eromanga (SA)	30	20	23	1.73	2	98
Iona	Otway (VIC)	41	134	6.3	1.73	2	98

All the cost assumptions in this report are for year *2023*. These are then projected to the respective years (stages) under study using a constant inflation rate of 2.5% per year. Their NPV also considers 2023 as reference year.

[10] The costs in Table 3 are taken from Table 1 in (Ennis-King et al., 2021) as 1.42 USD/kg H_2 in 2014 and then converted to 2023 equivalents by applying a constant inflation rate of 2.5% per year. An exchange rate of 1 USD = 1.44 AUD is used in this report.

4.1. Multi-stage planning: Without UHS

This section is a demonstration of the developed optimal *greenfield* multi-stage integrated infrastructure planning model described in Section 2 on the proposed provisional transmission corridors connecting REZ and hydrogen export ports shown in Figure 4, but without the candidate UHS facilities. Under the cost and technical assumptions of the specific case study in this section (see Table 3 and Appendix A: Cost and Parameter Assumptions), in which a greenfield multi-stage integrated electricity and hydrogen infrastructure planning model is used to find the most cost-effective infrastructure design that connects the REZ in AEMO's 2022 ISP (Australian Energy Market Operator, 2022a) (see Figure 4) *directly* to a single type of demand, namely large-scale green hydrogen (i.e., molecules), results show that hydrogen pipelines are more cost effective than their electricity counterparts under the specific corridor lengths and energy volumes in years (stages) 2027, 2032, and 2037 in this case study (see Figure 4). This is another way of saying that in this case it is more cost effective to co-locate large-scale electrolysis and VRE, and transport the produced green hydrogen in pipelines, as opposed to installing large-scale electrolysis at the location of the hydrogen demand (in this case the export ports).

The optimal solution in year (stage) 2037 is shown in Figure 5, which indicates that the optimisation model chooses pipelines exclusively as the most cost-effective transport infrastructure. The gradual installation of the optimal transport and storage infrastructure from 2027 to 2032 is shown in Figure 6 and Figure 7. Figure 5 also shows the optimal diameter of each hydrogen pipeline, along with the length of the pipeline. The total NPV of this optimal integrated infrastructure design is AUD 35.3 B. A breakdown of this total NPV is shown in Table 4 for each technology and for each considered state (excluding Tasmania). Table 4 also shows that electrolysers constitute the largest proportion (~70%) of the total cost under today's cost curves which estimate the cost of PEM electrolysers at around AUD 0.864 M/MW (see Table 14 in Appendix A: Cost and Parameter Assumptions). Table 5 provides a further breakdown of the NPV of the transport costs (pipelines + compressors) in each stage for each considered state (excluding Tasmania) at the optimal solution of the multi-stage integrated transport infrastructure problem for the considered *Hydrogen Superpower* scenario. Table 5 highlights the capability of the model to optimise the diameters of pipelines as well as their location to match the gradual increase in forecast hydrogen demand (see Table 1) and VRE capacity (Table 2) over the considered stages (2027, 2032, and 2037), while considering the lead time of building each asset (as 5 years in this report) and the variability of the RES. Non-anticipativity constraints, which ensure that an investment made at a certain stage (year) will be present in subsequent stages, can be seen by comparing Table 5 with Figure 5.

Table 5 also lists the maximum amount of linepack storage (in hours) that each hydrogen pipeline is providing in each year (stage). The table shows that in this specific case, all the hydrogen pipelines are providing more than 2 hours of storage to buffer the variability of RES. These results align with the findings in *Milestone 6 report* of this project, which suggest that in a scenario where 2 hours of storage duration are required, hydrogen pipelines are generally more cost effective than electricity transmission infrastructure (HVAC + BESS or HVDC + BESS) across most of the considered distances and energy volumes. More interestingly, the linepack profiles in Queensland and South Australia in 2037 shown in Figure 8 and Figure 15, respectively, show that the optimal pipeline network in Figure 5 can provide around ~16 hours of storage in Queensland (~380 TJ) and around ~54 hours of storage in South Australia (~982

TJ), both of which are much higher than 2 hours. Corresponding profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for Queensland and South Australia are shown in Figure 9 and Figure 14 (see Appendix B: Supplementary Material).

Figure 9 and Figure 14 also show that the profile of total accommodated VRE has a much lower variability compared to the available VRE, and this is because the optimisation model finds the optimal location for the minimum possible capacity of electrolysers to ensure supplying the total (gradually increasing) hydrogen demand using the smallest possible pipeline diameters that provide adequate storage capacity (linepack) that buffers the variability of the RES in each stage (year).

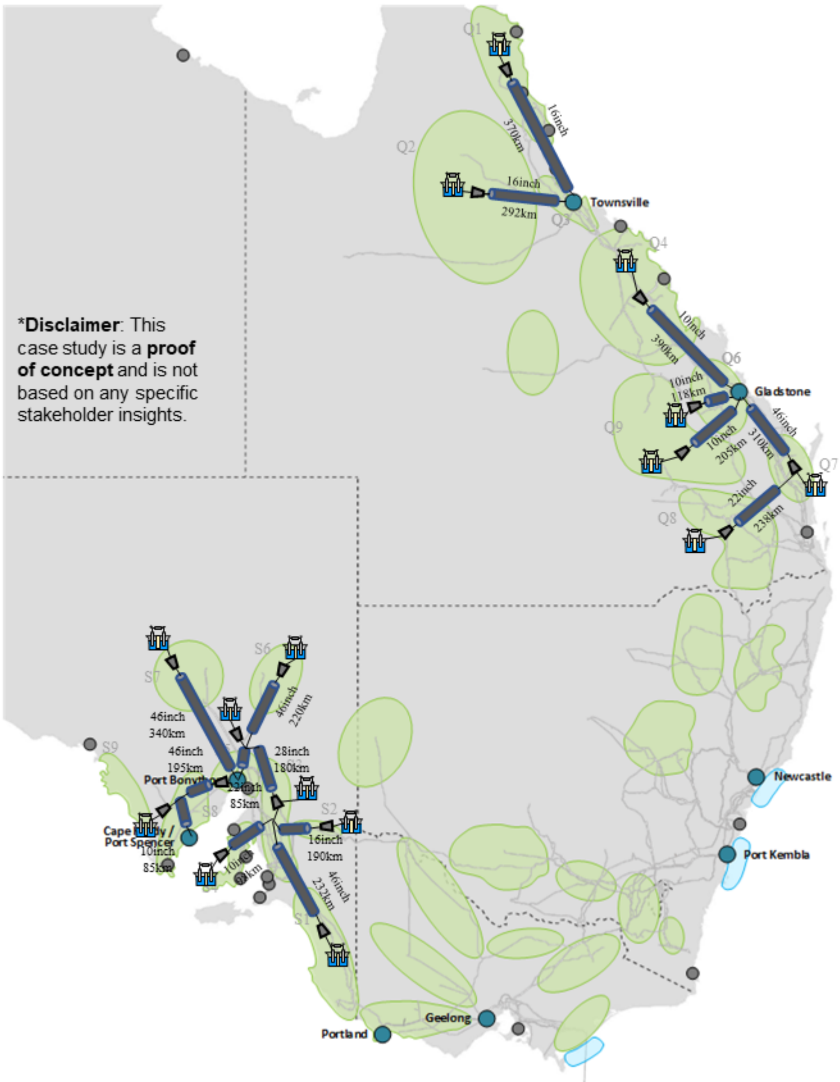


Figure 5: Optimal solution of the multi-stage integrated infrastructure planning problem for year (stage) 2037. Only pipelines are deemed as the optimal transport infrastructure in this case study.

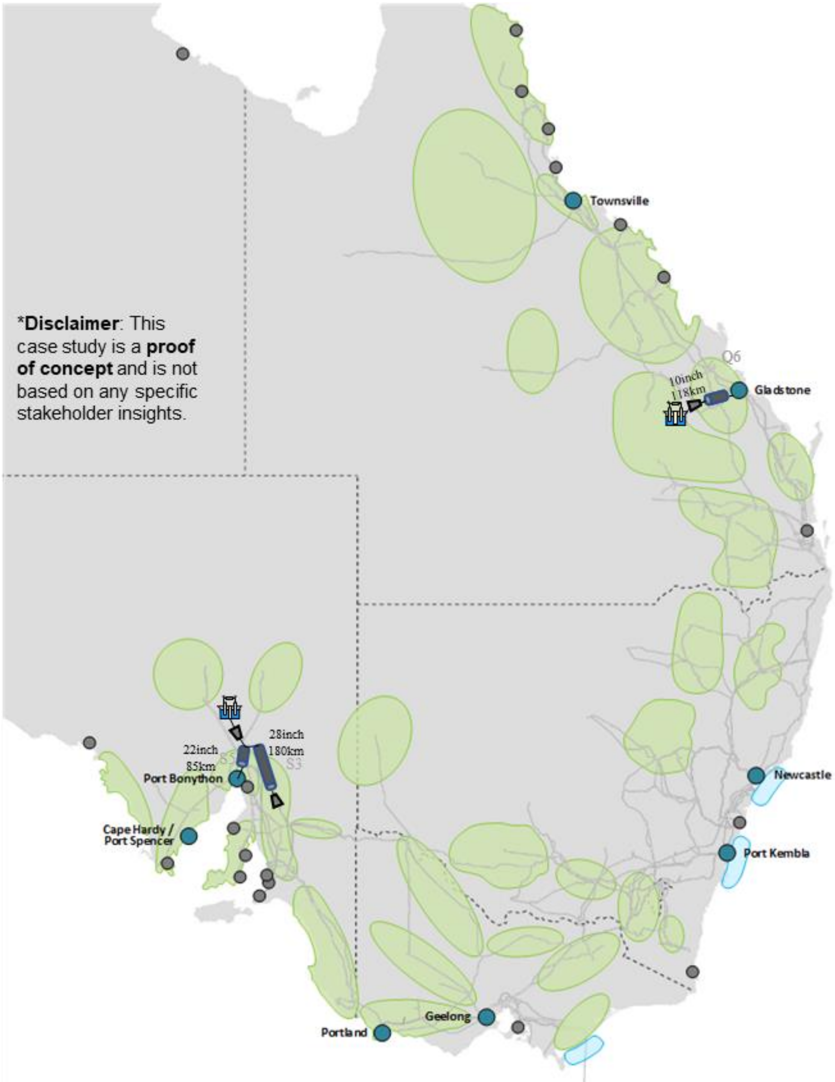


Figure 6: Optimal solution in year (stage) 2027.

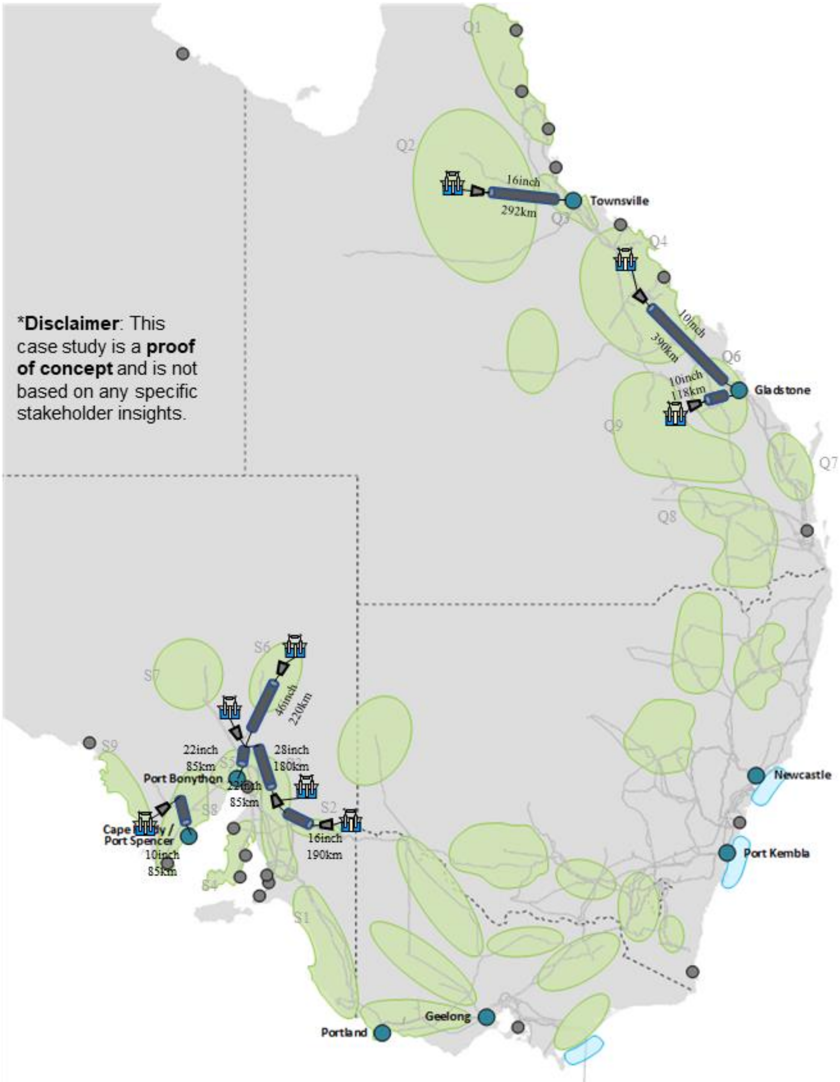


Figure 7: Optimal solution in year (stage) 2032.

Table 4: Breakdown of the total NPV for each technology and for each considered state (excluding Tasmania) at the optimal solution of the integrated multi-stage transport infrastructure problem for the considered *Hydrogen Superpower* scenario (see (Australian Energy Market Operator, 2022a)**) for years (stages) 2027, 2032, and 2037.**

	NPV (M AUD)						Total (B AUD)
State	**Pipelines**	**Compressors**	**HVAC**	**HVDC**	**BESS**	**PtG**	
NSW	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
QLD	3160.9	1717.1	0.0	0.0	0.0	7669.3	**12.5**
SA	6678.9	6428.8	0.0	0.0	0.0	9646.5	**22.8**
VIC	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	9839.7	8145.8	0.0	0.0	0.0	17315.8	**35.3**

Table 5: Breakdown of NPV of the transport costs (pipelines + compressors) in each stage for each considered state (excluding Tasmania) at the optimal solution of the integrated transport infrastructure problem for the considered *Hydrogen Superpower* scenario (see (Australian Energy Market Operator, 2022a)**). The table also shows the maximum amount of linepack storage (in hours) that each pipeline is providing in each year (stage).**

Corridor		Length (km)	D_n (inch)	Average throughput (MW)	Storage (hours)	NPV (MAUD)
From	**To**					
			2027			
Q6	Gladstone	118	10	99.4	9.0	197.7
S3	S5	180	28	344.8	36.0	1254.8
S5	Port Bonython	85	22	402.0	4.2	755.9
			2032			
Q2	Townsville	292	16	686.1	8.3	467.3
Q4	Gladstone	390	10	146.3	23.4	311.9
S2	S3	190	16	148.2	19.6	399.5
S6	S5	220	46	838.0	42.1	2848.7
S8	Cape Hardy	85	10	97.3	8.1	185.6
			2037			
Q1	Townsville	370	16	756.1	11.6	467.1
Q7	Gladstone	310	46	3245.0	13.8	2601.4
Q8	Q7	238	22	2094.2	4.0	646.3
Q9	Gladstone	205	10	182.7	9.9	186.3
S1	S3	232	46	782.6	42.7	2447.9
S4	S3	98	10	155.2	5.1	166.6
S7	Port Bonython	340	46	215.5	309.5	2703.9
Port Bonython	S8	195	46	412.1	113.4	2344.8
					Total NPV:	**17985.6**

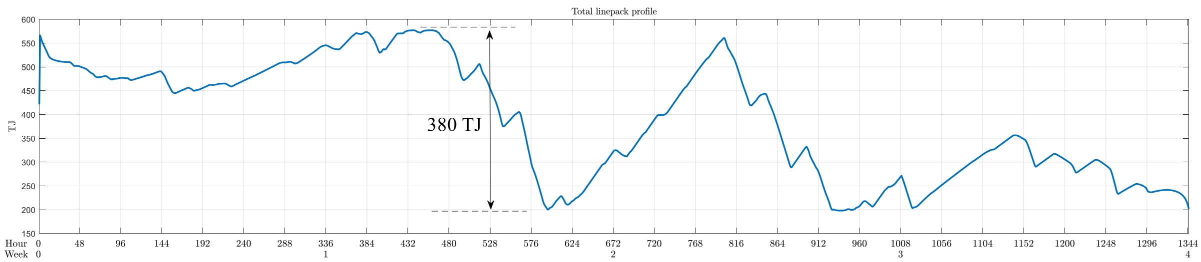


Figure 8: Profile of total linepack in the optimal hydrogen pipeline network in Queensland (see Figure 5) in year (stage) 2037. Note that the y-axis scale is from 150 TJ to 600 TJ.

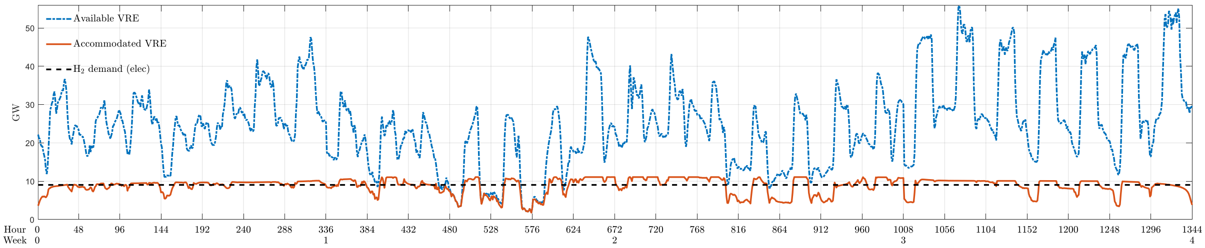


Figure 9: Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for Queensland under the optimal solution illustrated in Figure 5 for year (stage) 2037.

An interesting observation in this case study is the impact of the high variability of RES in South Australia on the total NPV. Table 4 shows that the total NPV in South Australia is AUD 22.8 B, which is almost double that of the total NPV in Queensland, despite a lower hydrogen demand in South Australia compared to Queensland (see Table 1). This high RES variability is evident when comparing Figure 14 to Figure 9. In particular, it can be seen from Figure 14 that many instances where the supply is much lower than the demand for an extended period of time, which necessitates much larger pipelines to store renewable energy in times when generation exceeds the demand. In other words, the optimisation model is now forced to install larger pipelines and large electrolysers to provide adequate linepack storage to meet the constant (total) hydrogen demand in South Australia in each year. This high amount of required linepack storage in South Australia can also be seen in Table 5, where some pipelines in South Australia are providing more than 40 hours of storage.

4.1.1. Comparison to a case with an incremental but myopic approach

To underscore the advantages of multi-stage planning, which is an incremental expansion approach characterised by a long-sighted outlook over the three considered years (stages), this subsection compares the optimal solution shown in Table 4, which obtained by solving Problem (1) in Section 3 to one obtained from an incremental but *myopic* planning approach that incrementally finds a solution by solving the single-stage planning problem[11] in each year (stage) and locking in investments found in early stages. The solution found by such a myopic approach, shown in Table 6, is AUD 4.75 B (~ 13%) more costly than the multi-stage solution in Table 4. This demonstrates how multi-stage planning enables future incremental expansion at *cheaper costs* by making forward-thinking investments that consider a long-sighted outlook over the evolution of both demand and RES capacity.

Looking at South Australia in particular, the multi-stage model in this case chooses the invest early in larger pipelines in anticipation for the high RES variability in subsequent years (stages). This can be seen in Table 5, and in particular in the 22-inch pipeline installed in S3-S5 in year 2027 and in the 46-inch pipeline installed in corridor S6-S5 in year 2032. Both of these pipelines are heavily underutilised in the early years (stages) they are installed in, as evidenced by a very low average steady-state throughput, whereas their average steady-state throughput dramatically increases in subsequent years to accommodate more VRE. On the other hand, adopting an incremental but myopic approach would incur higher costs of both

[11] See Problem (2) in Section 3 and Milestone 6 report for more details on single-stage planning.

pipelines and electrolysers in the long run, as can be seen in Table 6. It is this flexibility derived from pre-defining a cost-effective action of investing early in larger pipelines that provides investors with the *option value*.

Table 6: Breakdown of the total NPV for each technology and for each considered state (excluding Tasmania) for a solution found by an incremental but myopic approach.

	NPV (M AUD)						Total (B AUD)
State	**Pipelines**	**Compressors**	**HVAC**	**HVDC**	**BESS**	**PtG**	
NSW	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
QLD	3417.0	1398.6	0.0	0.0	0.0	9153.4	**14.0**
SA	7443.7	6560.2	0.0	0.0	0.0	12079.0	**26.1**
VIC	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	10860.7	7958.8	0.0	0.0	0.0	21232.4	**40.1**

4.1.2. Comparison with a case with only electricity options

This subsection compares the optimal solution shown in Table 4, which consists of pipeline options exclusively, with a solution that only considers electricity options, namely HVAC systems, HVDC systems, and BESS. The solution for a case with only electricity options, shown in Table 7, is more than 5x more expensive that the optimal one in Table 4. Looking at the BESS cost assumptions in Table 15, it is not surprising to find that BESS constitute the largest proportion of the NPV. In more detail, the high variability of RES and the assumption that the hydrogen demand is constant place stringent requirements on storage. This is witnessed in the optimal solution in Table 5 as well the linepack profiles in Figure 8 and Figure 15 for Queensland and South Australia in 2037 respectively, which show that the pipeline networks in both states are providing ~16h and ~54h of storage. Such astronomically high storage requirements, especially in South Australia, translate to substantially high costs of BESS as seen in Table 7.

These results are also congruent with the findings in Section 3.1 the Milestone 6 report which assessed the impact of capacity, corridor length, and amount of storage required on the transport and storage infrastructure investment decisions over a single corridor.

Table 7: Breakdown of the total NPV for each technology and for each considered state (excluding Tasmania) for an optimal solution for a case with only electricity options.

	NPV (M AUD)						Total (B AUD)
State	**Pipelines**	**Compressors**	**HVAC**	**HVDC**	**BESS**	**PtG**	
NSW	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
QLD	0.0	0.0	3368.6	2309.3	27393.4	7374.2	**40.4**
SA	0.0	0.0	3192.7	3997.1	147499.5	5339.2	**160.0**
VIC	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	0.0	0.0	6561.3	6306.4	174892.9	12713.4	**200.5**

As PHES is more suitable than BESS for long-duration storage, the cost of storage in Table 7 is expected to significantly decrease if PHES is considered as a long-duration storage option.

However, this would require a more targeted case study predicated on stakeholder consensus on the location of these candidate PHES sites. Such an assessment will be conducted as part of project "*RP1.1-07: Integrated electricity-hydrogen: future system and market interactions under different storage considerations*".

4.1.3. Comparison between steady-state and quasi-dynamic gas flow modelling

To highlight the importance of capturing the nonlinear behaviour of gas flow as well as linepack in capturing the variability of RES and in ensuring correct sizing of pipelines, the above results, which are obtained under a quasi-dynamic gas flow model, are compared against a case with a steady-state model of gas flow. Since steady-state gas flow modelling cannot capture RES variability (and linepack), capacity factors for wind and solar generators are used instead of the full VRE traces in 30-minute resolution. These capacity factors are obtained from AEMO's 2022 ISP (Australian Energy Market Operator, 2022a) as 0.477 and 0.291 for wind and solar generation respectively. In other words, the input RES generation profiles to the steady-state model are no longer variable, like the ones in Figure 9, but rather fixed capacity factors (i.e., average generation outputs over the whole planning horizon) for wind and solar. The results are shown in Table 8 which clearly shows a gross underestimation of the total cost of the pipeline network (~ AUD 2.3 B in Table 8 compared to ~ AUD 18 B in Table 5). This is not surprising since the steady-gas flow model does not capture the linepack, which manifests in an underestimation of the diameter of the pipelines when average supply (such as a capacity factors) is used instead of a variable one that can at times be exceeded by the demand, thus necessitating larger pipelines to provide storage in the form of linepack.

Table 8: Results of the multi-stage integrated transmission infrastructure planning under steady-state gas flow modelling under *capacity factors* of 0.477 and 0.291 for wind and solar generation respectively.

Corridor		Length (km)	Pipeline D_n (inch)	Average throughput (MW)	NPV (MAUD)
From	**To**				
2027					
Q6	Gladstone	118	16	99.36	387.8
S3	S5	180	6	75.15	132.9
S5	Port Bonython	85	20	276.32	633.9
S8	Cape Hardy	85	6	125.71	116.7
2032					
S6	S5	220	22	1207.98	734.1
2037					
Q2	Townsville	292	12	802.43	272.1
Q3	Townsville	49	8	747.98	98.1
Q7	Gladstone	310	20	2349.76	591.9
				Total NPV:	**2258.8**

4.2. Multi-stage planning: With UHS

This section expands the case study above by allowing the model to consider UHS facilities as a means for storing hydrogen. The optimal solution depicted in Figure 10 indicates that the model chooses to invest in the UHS facilities in Roma Queensland (see Table 3). All other UHS facilities were not deemed as economically competitive in this greenfield integrated planning problem. This UHS facility is chosen to be installed in 2037. Interestingly, investing in the UHS facility in Roma in 2037 substantially decreases the total NPV by around AUD 2.3 B (~6.5%), from AUD 35.3 B to AUD 33 B. A breakdown of this total NPV is shown in Table 9 for each technology and for each considered state (excluding Tasmania).

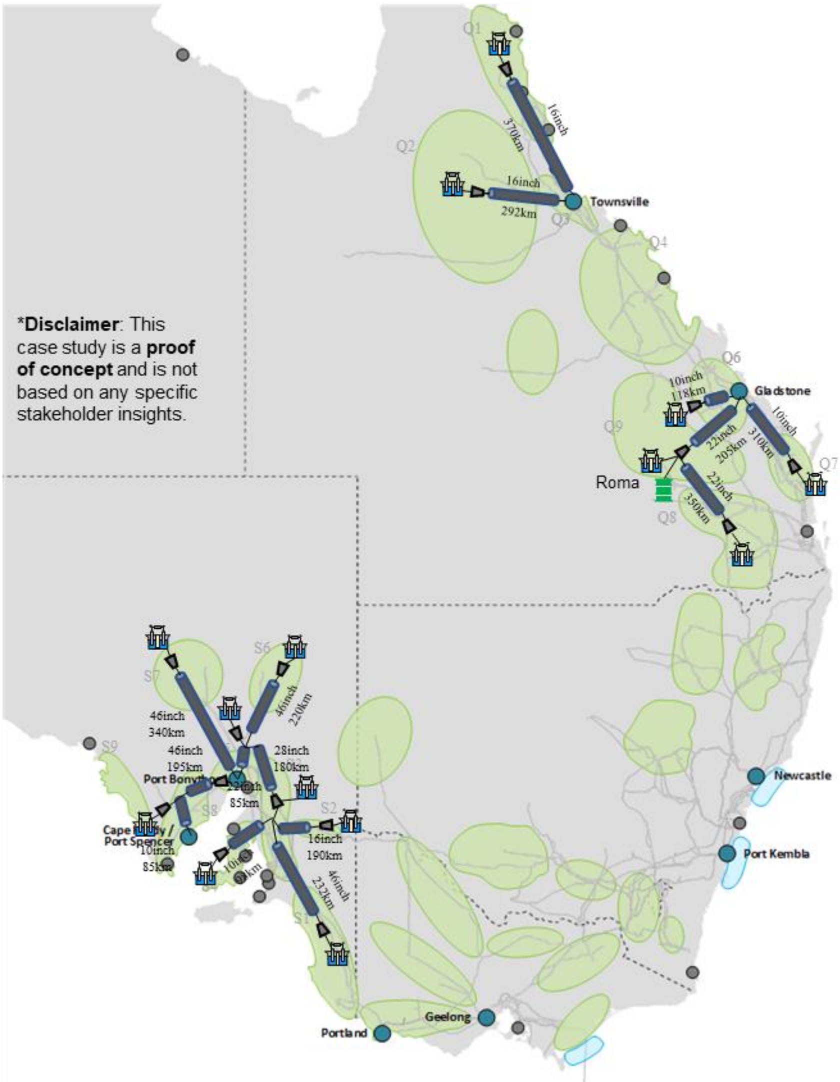


Figure 10: Optimal solution of the integrated infrastructure and storage planning problem for the considered multi-stage scenario with years (stages) 2027, 2032, and 2037. The model chooses to invest in only one of the two UHS facilities in Queensland (Roma). This UHS is installed in 2037, as optimally deemed by the developed model.

Table 10 provides a further breakdown of the NPV of the transport costs (pipelines + compressors) in each stage for each considered state (excluding Tasmania) at the optimal solution of the multi-stage integrated transport infrastructure problem for the considered *Hydrogen Superpower* scenario.

Table 10 highlights the capability of the model to optimise the diameters of pipelines as well as their location to match the gradual increase in forecast hydrogen demand (see Table 1) and VRE capacity (Table 2) over the considered stages (2027, 2032, and 2037), while considering the lead time of building each asset (as 5 years in this report) and the variability of the RES. Non-anticipativity constraints, which ensure that an investment made at a certain stage (year) will be present in subsequent stages, can be seen by comparing Table 10 with Figure 10. Table 10 also lists the maximum amount of linepack storage (in hours) that each hydrogen pipeline is providing in each year (stage). The impact of the UHS in displacing linepack storage can be seen by comparing the pipeline storage in Queensland in Table 10 with the ones in Table 5.

The main reason for this decrease in NPV is that the marginal cost of storage of the UHS facility in Roma is much lower compared to that of a pipeline, which generally requires increasing its diameter to provide additional storage, as described in the Milestone 6 report. If there is not enough headroom in the pipeline the extra storage requirement comes at the expense of increasing its diameter, and thereby its overall cost. As a result, the storage capacity gained from installing the UHS in Roma displaces more expensive storage (linepack) in adjacent pipelines as well as other remote pipelines in the Queensland network, thereby resulting in the downsizing of these pipelines. In other words, the increase in cost (AUD 204.8 M) due to investing in the UHS facility in Queensland in 2037 is offset by a much larger decrease in cost (4877.9 + 7669.3 – (2747.8 + 7337.6 + 204.8) = AUD 2.257 B) from downsizing adjacent pipelines (and also PtG). This downsizing can be seen by comparing the pipeline networks in Queensland in Figure 10 and Figure 5. The total storage profile of the UHS facility in Roma (see Table 3), which can provide ~3215 TJ of storage over the considered 4 representative weeks, is shown in Figure 11, and the associated profiles of injections and withdrawals are shown in Figure 12. In fact, this displacement in linepack capacity can be seen in Figure 13, which shows the profile of the total linepack in Queensland for the optimal solution shown in Figure 10. The total linepack capacity is now ~144 TJ compared to ~380 TJ in the case without the UHS facility in Roma, Queensland (see Figure 8), a ~236 TJ decrease thanks to the additional UHS storage capacity.

Table 9: Breakdown of the total NPV for each technology and for each considered state (excluding Tasmania) at the optimal solution of the integrated multi-stage transport and storage infrastructure problem for the considered *Hydrogen Superpower* scenario (see (Australian Energy Market Operator, 2022a)**) for years (stages) 2027, 2032, and 2037.**

	NPV (M AUD)					Total (B AUD)
State	Pipelines	Compressors	HVAC+HVDC+ BESS	UHS	PtG	
NSW	0.0	0.0	0.0	0.0	0.0	**0.0**
QLD	2012.4	735.4	0.0	204.8	7337.6	**10.3**
SA	6678.9	6428.8	0.0	0.0	9646.5	**22.8**
VIC	0.0	0.0	0.0	0.0	0.0	**0.0**
	8691.3	7164.2	0.0	204.8	16984.1	**33.0**

Table 10: Breakdown of NPV of the transport costs (pipelines + compressors) in each stage for each considered state (excluding Tasmania) at the optimal solution of the integrated transport and storage infrastructure problem for the considered *Hydrogen Superpower* scenario (see (Australian Energy Market Operator, 2022a)**). The table also shows the maximum amount of linepack storage (in hours) that each pipeline is providing in each year (stage).**

Corridor		Length (km)	D_n (inch)	Average throughput (MW)	Storage (hours)	NPV (MAUD)
From	**To**					
2027						
Q6	Gladstone	118	10	99.4	9.0	197.7
S3	S5	180	28	344.8	36.0	1254.8
S5	Port Bonython	85	22	402.0	4.2	755.9
2032						
Q2	Townsville	292	16	467.3	5.8	467.3
Q7	Gladstone	310	10	141.2	17.7	262.1
S2	S3	190	16	148.2	19.6	399.5
S6	S5	220	46	838.0	42.1	2848.7
S8	Cape Hardy	85	10	97.3	8.1	185.6
2037						
Q1	Townsville	370	16	1199.7	6.4	467.1
Q9	Gladstone	205	22	2689.2	2.3	600.0
Q8	Q9	350	22	2465.8	5.3	753.8
S1	S3	232	46	782.6	42.7	2447.9
S4	S3	98	10	155.2	5.1	166.6
S7	Port Bonython	340	46	215.5	309.5	2703.9
Port Bonython	S8	195	46	412.1	113.4	2344.8
					Total NPV:	**15855.5**

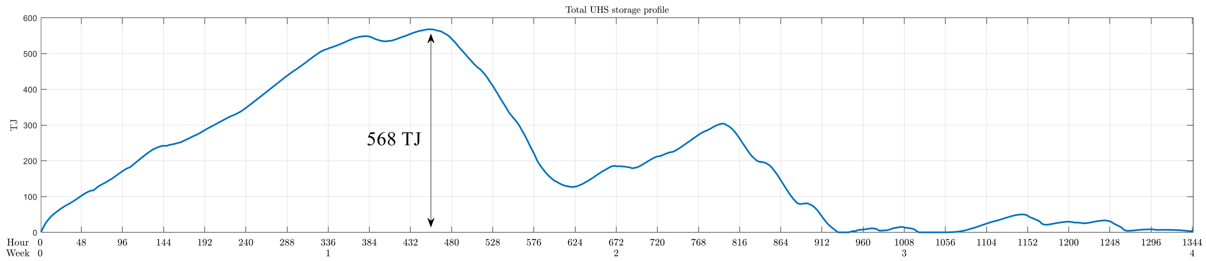


Figure 11: Total storage profile of the UHS facility in Roma (see Table 3) in year (stage) 2037. This UHS facility can provide ~568 TJ of storage over the selected 4 representative weeks.

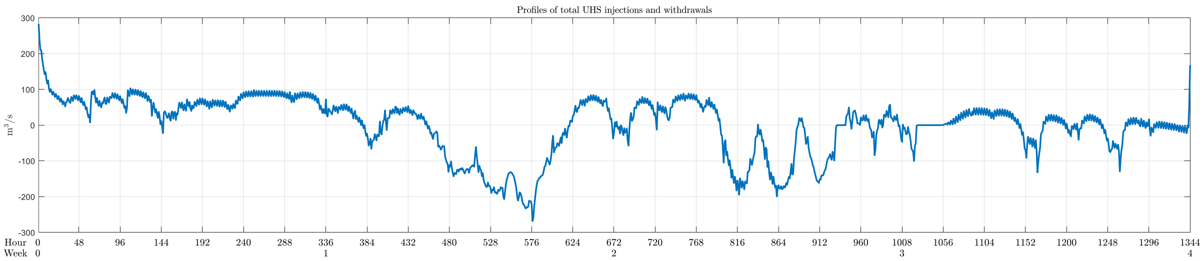


Figure 12: Total profiles of injections (positive) and withdrawals (negative) of the optimally selected UHS facility in Roma (see Figure 10) in year (stage) 2037.

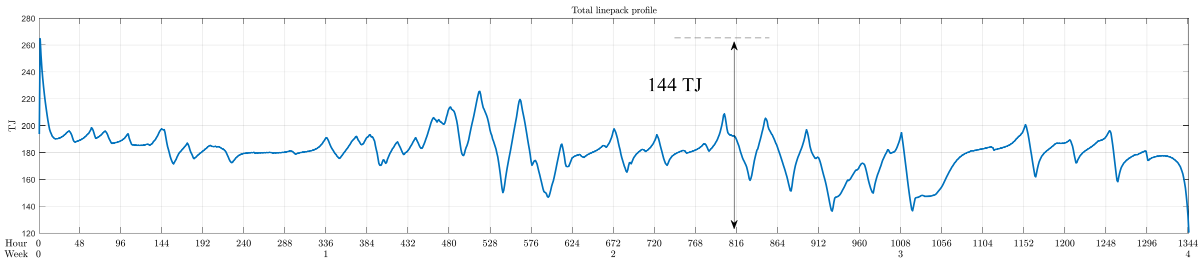


Figure 13: Profile of total linepack in the optimal hydrogen pipeline network in Queensland (see Figure 10) with the UHS in Roma in year (stage) 2037. Note that the y-axis scale is from 120 TJ to 280 TJ.

Although the UHS facility in Moomba (see Table 3 and Figure 4) is expected to have a larger capacity compared to the one in Roma, the main reason the model did not choose to invest in it is because of its remoteness from the REZ identified in AEMO's 2022 ISP, which would require building an additional pipeline of length of around 300 km to connect it to the rest of the hydrogen pipeline network in South Australia, thus increasing the total NPV instead of decreasing it. Similar reasoning applies to the Iona UHS facility in Victoria.[12]

It should be noted that the UHS is assumed completely empty at the start of the planning (optimisation) horizon to ensure fairness. Any other assumption on the initial storage would engender an unfair economic advantage in favour of installing the UHS, as the cost of that initial storage will be assumed as zero. Assuming the UHS is full greatly impacts the optimal solution, which not only manifests in smaller pipelines but also in much smaller PtG capacity, as this assumption also entails that the required capacity of electrolysers to convert VRE to the green hydrogen initially present in the UHS and the cost of that conversion are *not* accounted for.

[12] Results may be different if the analysis considered the cost of repurposing existing natural gas pipelines to support 100% hydrogen, alongside installing new hydrogen pipelines.

5. CONCLUSION

To address the challenging question of whether to transport large-scale VRE as molecules in hydrogen pipelines or as electricity in electricity transmission lines, this report introduced a first-of-its-kind mathematical optimisation framework for finding the optimal *greenfield multi-stage* integrated planning of electricity and hydrogen transmission and storage infrastructure. The model fills the gap in existing state-of-the-art literature by:

- Considering all relevant infrastructure technologies such as HVDC, HVAC, reactive power compensation, and hydrogen pipelines and inlet compressors, and by
- Incorporating essential nonlinearities such as voltage drops due to impedances in HVAC and HVDC transmission lines, losses in HVDC converter stations, reactive power flow, pressure drops in pipelines, linepack, and nonlinear withdrawal/injection rates of UHS systems, all of which play an important role in determining the optimal infrastructure investment decision.
- Extending the modelling to multi-stage planning that enables future incremental expansion at *cheaper costs* by capturing the gradual growth in hydrogen demand and VRE capacity, in addition to lead time of construction of the assets. The multi-stage model also provides insights into the *option value* of investing early in larger pipelines in anticipation for high RES variability and/or uncertainty in the amount of installed RES capacity in subsequent years.

The capabilities of this model are demonstrated on a proof-of-concept case study divided into two parts. The first part demonstrates the scalability of the developed model over a network with multiple variable supplies and demands and multiple stages by considering all the REZ stipulated in AEMO's 2022 ISP and connecting them with provisional corridors to the hydrogen export ports whose demands are specified in AEMO's 2022 ISP under the *Hydrogen Superpower* scenario for years (stages) 2027, 2032, and 2037. The second part considers candidate UHS facilities in the form of depleted gas fields, which can offer medium and long duration storage that plays a crucial role in buffering the variability of RES.

Under the specific cost assumptions, technical assumptions, corridor lengths, energy volumes, storage requirements, VRE forecasts, specific type and variability of this demand, and hydrogen export demand forecasts in this case study, in addition to the very nature of greenfield expansion planning in which no interaction with existing electricity and natural gas infrastructure is considered, the findings suggest that:

- Compared to an incremental but *myopic* planning approach that incrementally finds a solution by solving a single-stage planning problem in each year (stage) and locking in investments found in early stages, the multi-stage model, which is a single optimisation problem that considers all the stages simultaneously, is demonstrated to enable future incremental expansion at *cheaper costs* by making forward-thinking investments that consider a long-sighted outlook over the evolution of the demand and RES capacity. Under the considered case study, the solution found by the multi-stage planning model is AUD 4.75 B (~ 13%) cheaper than the solution found by an incremental but myopic planning approach (i.e., solving a single-stage planning problem in each year).
- The multi-stage model can capture the *option value* of installing larger pipelines in early years of the planning horizon in anticipation for uncertainty in RES capacity and location of investment in subsequent years and the high RES operational variability that may call for larger storage requirements. This is witnessed predominantly in South Australia when considering stages (years) 2027, 2032, and 2037. It is this flexibility derived from pre-

defining a cost-effective action of investing early in larger pipelines that provides investors with the *option value*.

- Under steady-state throughputs (where no storage is required) hydrogen pipelines are more cost effective than their electricity counterparts across all the capacities and distances considered in this report. More details on this analysis can be found in the Milestone 6 report.
- Pipelines are once again deemed as the optimal transport infrastructure across all the considered planning stages (2027, 2032, and 2037). This is predominantly due to the high variability of RES, which requires in some cases more than 8 hours of storage to buffer this variability. Linepack storage is of utmost importance in this case as the RES supply is variable and the hydrogen export demand is assumed constant in each year (stage) state (QLD and SA) but distributed, not necessarily equally, over the envisaged hydrogen export ports in each state. These results align with the findings in the Milestone 6 report single corridor case study.
- The multi-stage model demonstrates the ability to capture the *option value* of installing larger pipelines in early years of the planning horizon in anticipation for uncertainty in RES capacity and location of investment in subsequent years and the high RES operational variability that may call for larger storage requirements. This is witnessed predominantly in South Australia when considering stages (years) 2027, 2032, and 2037.
- Investing in UHS in the form of depleted gas fields in specific locations in Australia can significantly *decrease* the total investment costs of transport and storage infrastructure. This is because the marginal cost of storage in the considered UHS facilities is much lower than that of a pipeline, and as a result the storage capacity gained from installing the UHS can displace more expensive storage (linepack) in adjacent pipelines, thereby resulting in the downsizing of these pipelines.
- In contrast to existing works, which are predominantly limited to a single corridor with static supplies and demand profiles, the developed optimisation-based modelling can find the *optimal* integrated transport and storage infrastructure design over a *network* with arbitrary topology and with multiple variable supplies and demands, and multiple stages (years). In contrast to a single corridor, optimising over a network with more than one corridor adds *geographical location* and RES variability to the list of defining factors that impact the optimal infrastructure and storage design. At first glance, it might appear that the single-corridor analysis prevalent in existing literature can be applied to a network by treating each corridor independently, nonetheless such an approach quickly becomes infeasible even for a simple network with one variable renewable energy hub connected to two variable hydrogen demand points via two corridors with different lengths. In other words, having more than one corridor entails finding the *optimal* compromise between (i) energy volumes, (ii) distance, (iii) storage requirements, *and* (iv) geographical location, in addition to (v) variability RES. Furthermore, optimising over multiple stages (years) further adds the gradual growth in hydrogen demand and VRE capacity, the lead time of building the assets, as well as the *option value* of investing early in larger pipelines (e.g., in anticipation for high RES variability and/or uncertainty in the amount of installed RES capacity in subsequent years) to the list of defining factors that impact optimal infrastructure and storage design, thus making the analysis much more complex. Despite this complexity, the novel insights and assessments in this report are made possible thanks to state-of-the-art mathematical optimisation methods and scalable numerical algorithms.

This assessment does not consider electricity as demand – it only considers green hydrogen as export demand, with no assumptions of what this green hydrogen is used for. It should also be emphasised that the assessment and case studies in this report are classified under *greenfield* integrated expansion planning that optimises *newly* built electrolysis, transmission, and storage infrastructure network in *isolation* from existing infrastructure, for a specified constant (but increasing each year) green hydrogen export demand distributed (not necessarily equally) over the envisaged hydrogen export ports in each state.[13] In other words, this greenfield assessment does not consider the interactions between this newly built infrastructure network and the existing electricity transmission infrastructure such as the one in the National Electricity Market (NEM). The findings in this report might thus change if these interactions are considered as other elements in the electricity system (e.g., flexible generation, BESS, pumped hydro energy storage (PHES), and transmission network) could provide flexibility to buffer variability from RES, thereby potentially displacing additional storage requirements in pipelines. The assessment also neglects water requirements for electrolysers due to lack of data, which might also alter the findings when included. All the cost assumptions in this report are for year *2023*. Their NPV also considers 2023 as reference year. In addition to pipelines, other viable options for hydrogen transportation include tanker trucks and tube trailers. These options are discussed in more detail in the *Milestone 3: Literature review* of the project.

6. NEXT STEP AND FUTURE WORK

Future work, which will mainly be conducted under project "*RP1.1-07: Integrated electricity-hydrogen: future system and market interactions under different storage considerations*", will leverage the modelling of UHS and hydrogen pipelines in this project, together with the electricity network modelling developed in "RP1.1-02A: Regional case studies on multi-energy system integration" to assess the impact of different storage considerations and large-scale grid-connected electrolysers in future integrated electricity-hydrogen systems on the security, reliability, and resilience of the NEM and future electricity-hydrogen systems in general in Australia.

Project RP1.1-07 will also extend the current modelling and cost assumptions of UHS in depleted gas reservoirs to consider buffer systems, hydrogen mixing with existing gases in the reservoir and subsequent purification requirements, and the capital cost of cushion gas (hydrogen) and the compression system (Salmachi et al., 2023).

[13] The total hydrogen demand in each state is assumed constant – converted from Mt/year to m^3/s. However, instead of dividing this hydrogen demand equally across the export ports stipulated in AEMO's 2022 ISP for each state, the model is setup to choose how to *optimally* distribute (i.e., with potentially varying proportions) this hydrogen demand across these ports.

APPENDIX A: COST AND PARAMETER ASSUMPTIONS

This appendix lists the assumptions on input technical parameters and costs of hydrogen pipeline links in Table 11, HVAC links in Table 12, HVDC links in Table 13, electrolysers in Table 14, and battery storage systems in Table 15. These cost estimates are obtained from various reliable publicly available sources, including AEMO (Australian Energy Market Operator, 2022a) and the peak body representing Australian pipeline infrastructure (GPA Engineering, 2022). Cost estimates of pipelines and compressors fall under Class 4 of the Association for Advancement of Cost Engineering (AACE) classification system with a CapEx accuracy of -30%/+50%, whereas cost estimates of HVAC and HVDC links fall Class 5 (±30%). Cost assumptions for UHS facilities can be found in Table 3. All the cost assumptions in this report are for year *2023*. These are then projected to the respective years under study (e.g., 2027, 2032, and 2037) using a constant inflation rate of 2.5% per year. Their NPV also considers 2023 as reference year.

Table 11: Cost and parameters assumptions of pipelines and compressors (GPA Engineering, 2022)**.**

Parameter		Option			
Diameter (inch)		4	6	…	46
Minimum pressure (MPa)		3	3	…	3
Maximum allowable operating pressure (MPa)		12	12	…	12
Specified minimum yield strength (psi)		52000	52000	…	52000
Design factor		0.5	0.5	…	0.5
Erosional velocity ratio		0.8	0.8	…	0.8
Manufacturing cost (USD/Tonne)		2649	2649	…	2649
Insurance and freight (USD/Tonne)[14]		218	218	…	218
Installation cost (kAUD/ inch/km)[15]	<100 km	70	70	…	70
	<250 km	50	50	…	50
	<500 km	40	40	…	40
	>500 km	37.8	37.8	…	37.8
Engineering costs (% of procurement and installation costs)	≤100 km	10	10	…	10
	>100 km	5	5	…	5
OpEx (% of CapEx)	≤50 km	3.75	3.75	…	3.75
	≤100 km	3.25	3.25	…	3.25
	≤200 km	2.25	2.25	…	2.25
	≤500 km	2.11	2.11	…	2.11
	>500 km	1.875	1.875	…	1.875

[14] Insurance and freight costs are from the supplier (Welspun) to Port Hedland, Western Australia (GPA Engineering, 2022).
[15] Please refer to (GPA Engineering, 2022) for a full list of factors that installation costs include.

Compressors	See Tables 6, 26, and 27 in (GPA Engineering, 2022).

Table 12: Cost and parameters assumptions of HVAC links (Australian Energy Market Operator, 2022b; Prysmian Group, 2015)**.**

Parameter		Option						
Voltage (kV)		500	500	330	275	330	275	132
OHL cost (MAUD/km)		3.747	2.907	2.839	2.205	2.041	1.717	1.241
OpEx (% of CapEx)	<250 km	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	≥250 km	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Capacity (MVA)		6080	2900	2400	1900	1000	536	169
Circuits		Double	Single	Double	Double	Single	Single	Single
Conductor		Orange	Orange	Mango	Olive	Orange	Lemon	Mango
Bundle		4	4	3	2	2	2	1
Resistance (Ω/km)		0.0207	0.0207	0.0322	0.0358	0.0413	0.0835	0.0967
Reactance (Ω/km)		0.2603	0.2603	0.2685	0.3027	0.3051	0.3149	0.3994
Shunt admittance (µS/km)		4.22	4.22	4.09	3.63	3.60	3.49	2.75
Substation 1 cost (MAUD)		178.5	107.9	89.7	78.9	45.8	26	12.3
Substation 2 cost (MAUD)		172.2	107.9	89.7	54	45.8	26	12.3

Table 13: Cost and parameters assumptions of HVDC links (Australian Energy Market Operator, 2022b; Prysmian Group, 2015)**.**

Parameter		Option	
Voltage (kV)		±320	±500
Capacity (GW)		1.5	2
OHL cost (MAUD/km)		1.99	2.54
Resistance (Ω/km)		0.0119	0.0119
Converter station 1 (MAUD)		474.68	507.37
Converter station 2 (MAUD)		357.82	509.20
OpEx (% of CapEx)	<250 km	0.5	0.5
	≥250 km	0.25	0.25
Alpha (MW)		6.62	6.62
Beta (V)		1800	1800
Gamma (Ω)		1.98	1.98
Technology		HVDC - VSC	HVDC - VSC
Details		2 × Asymmetrical Monopole (Bipole metallic return)	2 × Asymmetrical Monopole (Bipole metallic return)

Table 14: Cost and parameters assumptions of electrolysers (Reuß et al., 2017, 2019).[16]

Parameter	Value
Capacity of a single electrolyser (MW)	17.5
Electrolyser unit cost (MUSD)	10.5
OpEx (% of CapEx)	2
Efficiency (%)	70
Water consumption (kg/kg H_2)	10
Technology	PEM

Table 15: Cost and parameter assumptions of battery storage systems (GPA Engineering, 2022; Graham et al., 2022)**.**

Parameter		Value (AUD/MWh)
CapEx (AUD/MWh)	1 h	820,000
	2 h	550,000
	3 h	500,000
	4 h	450,000
	8 h	410,000
OpEx (AUD/kWh/year)		7.5
Efficiency (%)		95
Technology		Lithium-Ion

[16] The model can readily include different sizes and types of electrolysers.

APPENDIX B: SUPPLEMENTARY MATERIAL

Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for South Australia are shown in Figure 14. The total linepack profile in the optimal hydrogen pipeline network in South Australia is shown in Figure 15.

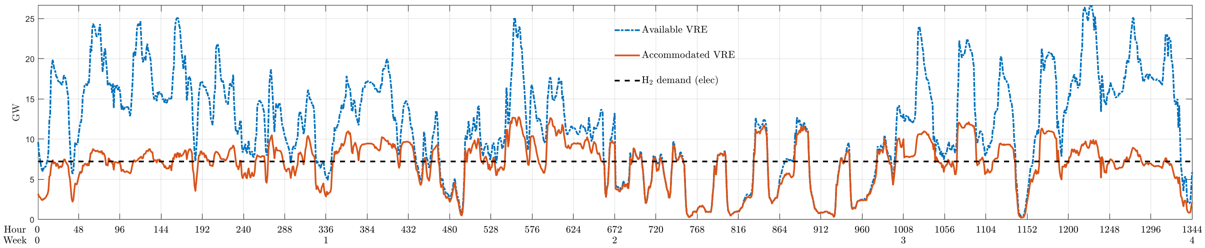


Figure 14: Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for South Australia under the optimal solution (see Figure 5) in year (stage) 2037.

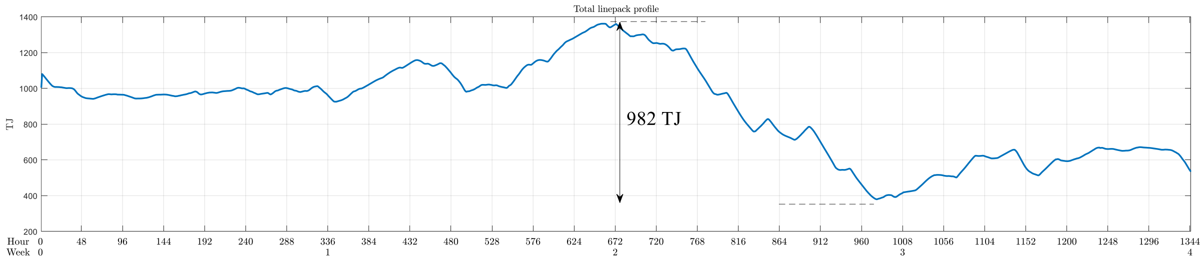


Figure 15: Profile of total linepack in the optimal hydrogen pipeline network in South Australia (see Figure 5) in year (stage) 2037.

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