11 February 2022

Submission: 2022 Draft Integrated System Plan Consultation

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure with a focus on high-pressure gas transmission. APGA's members build, own and operate the gas transmission and processing infrastructure connecting natural and renewable gas production around the country to demand centres in cities and elsewhere. Offering a wide range of services to gas users, retailers and producers, APGA members ensure the safe and reliable delivery of 28 per cent of the end-use energy consumed in Australia and are at the forefront of Australia's renewable gas industry, helping achieve net-zero as quickly and affordably as possible.

APGA welcomes the opportunity to contribute to the Australian Energy Market Operator (AEMO) 2022 Draft Integrated System Plan (ISP) Consultation (the **Consultation**).

APGA supports a net zero emission future for Australia by 2050[1]. As set out in Gas Vision 2050[2], APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC[3], which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy.

APGA is pleased to see three key changes in AEMO's approach within the 2022 Draft ISP.

1. **Recognition of the rapidly advancing pace of change in the Australian energy market** through utilisation of the Step Change Scenario as the central scenario;
2. Recognition that **Gas Power Generation (GPG) will continue to be critical** within the generation mix through to 2050; and
3. Recognition that **a future in which Australia maximises its renewable gas potential** is the future in which **net zero emissions energy could be achieved fastest** and with the **greatest opportunity for the Australia economy**.

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[1] APGA Climate Statement
https://www.apga.org.au/apga-climate-statement
[2] Gas Vision 2050, APGA
https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[3] Future Fuels CRC Website
https://www.futurefuelscrc.com/

APGA provides the following feedback to assist in the development of the best possible ISP.

The importance of hydrogen infrastructure
The Hydrogen Superpower scenario currently only considers transportation of energy as electrons, with all hydrogen produced at demand sites. Section 3.12 of the 2021 Inputs, Assumptions and Scenarios Report (IASR) indicates AEMO is aware of the options for hydrogen and will consider modelling transportation of hydrogen as gas in future ISPs. APGA considers this an issue of paramount importance.

Hydrogen pipelines are a significantly more cost-effective energy transport and storage solution compared to electricity powerlines, utility scale batteries and pumped hydro energy storage. This has been shown in a recent report commissioned by APGA which directly compares these options across various distances and throughputs[4]. Hydrogen customers may be able to access lower hydrogen costs when hydrogen is produced at the electricity source and piped to the customer in comparison to when electricity is transmitted to electrolysis closer to the customer.

This report aligns with the 2020 Frontier Economics report which indicates that using 100% green hydrogen to decarbonising gas use would come at around half the additional cost of electrifying gas demand. The lower cost of hydrogen infrastructure means that it is economically impractical to assume that all electricity used for hydrogen production would be supplied via the NEM. Access to lower cost energy transport and storage via hydrogen pipelines would have the following implications:

1. Where electricity for the purposes of significant (greater than 100MW) hydrogen production is currently considered to be supplied via the NEM, it will be much more cost effective for electrolysis to be supplied electricity from behind the meter variable renewable electricity (VRE) and for hydrogen to be piped to the customer; and
2. Where the electrification of customer energy demand could technically be supplied by hydrogen, the lower cost of hydrogen infrastructure compared to electricity infrastructure could result in a lower net zero energy cost for customers through hydrogen rather than electrification, leading to lower and less challenging rates of electrification required for Australia to achieve its net zero emission goal.

These implications warrant further investigation in order to deliver the lowest costs to consumers. The high levels of electrification currently modelled under the Step Change scenario may change if interconnected with a viable hydrogen market. APGA recommends that Hydrogen Pathway 3 from Figure 54 of the IASR should be investigated as a matter of priority for both domestic and export applications.

APGA is not advocating for a future in which all energy transport and storage occurs via energy pipelines. Rather, APGA anticipates a future in which the relative merits of both pipeline and powerline infrastructure result in a blended, highly integrated system. This is

[4] Please see attached to this submission:
Pipelines vs Powerlines: a summary; and
Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context

not only theory but the practical experience of today's energy market in which gas and electricity networks operate side by side to deliver near equivalent volumes of energy to Australian households and businesses today.

Existing technologies offer predictable NEM reliability

Heavy reliance on depletable utility scale energy storage and opt-in Distributed Energy Resources (DER) means the 2022 Draft ISP reliability strategy relies upon technologies less reliable than the current NEM. The latter of these is of most concern. Energy customers will have the ability to remove their DER devices as they choose, disrupting the ability for the NEM to rely upon these resources. APGA recognises that economic models struggle with redundancy while physical models thrive on it, however balance is needed between the two modelling approaches on the topic of reliability.

In 2021, the Grattan Institute proposed that 90% variable renewable generation combined with 10% firm, dispatchable generation could deliver the lowest cost net-zero NEM by 2050[5]. Grattan identify mature technologies such as GPG (with offsets) as central to this opportunity. APGA notes that firm dispatchable generation currently drops below 10% by 2038-39 in the 2022 Draft ISP Step Change scenario, and below 6% by 2050.

Key to the forms of dispatchable generation identified as being critical by Grattan is the ability for today's highly reliable dispatchable generation market to draw its fuel supply from much larger adjacent markets. By drawing from these much larger markets, dispatchable generation like gas power generation rarely finds itself without access to fuel supply. This is a significant difference between the dispatchable generation of today and the dispatchable energy storge technologies proposed as the basis for grid reliability under the Step Change scenario.

Development of a 'Plan A' and 'Plan B' for energy security under the central Step Change scenario could help AEMO ensure deeply reliable technologies are considered alongside part of the plan in case options relying on more discrete energy stores or public energy market engagement prove unreliable.

Existing technologies offer predictable NEM security

The 2022 Draft ISP security strategy relies upon *advanced inverters with grid-forming capabilities*. AEMO notes in its *Application of Advanced Grid-scale Inverters in the NEM* white paper that the *potential [of advanced inverters] is not demonstrated at the necessary scale, and focused engineering development is urgently needed to address the remaining issues and realise the promise of this technology*[6]. This reliance on advanced inverters is despite there being technologically mature energy security options available upon which AEMO could have founded the 2022 Draft ISP central Step Change scenario.

In recognition of both the importance and complexity of energy security in the NEM, APGA proposes that the reliance on 'potential' technologies within the ISP be carefully considered

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[5] Go for Net-Zero, The Grattan Institute 2021
https://grattan.edu.au/wp-content/uploads/2021/04/Go-for-net-zero-Grattan-Report.pdf

[6] Application of Advanced Grid-scale Inverters in the NEM, AEMO 2021
https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf

by AEMO, especially where proven technologies exist and could have been included within its modelling[7]. Development of a 'Plan A' and 'Plan B' for energy security under this scenario could ensure appropriately mature technologies are considered alongside 'potential' technologies.

Recognising that it may not be practical to undertake significant remodelling and amendment of the 2022 Draft ISP prior to its delivery, APGA provides recommendations ahead of the 2022 ISP delivery alongside recommendations ahead of 2024 ISP delivery:

2022 ISP recommendations

- **Recognise that energy transport and storage by pipeline could result in lower cost, lower complexity scenarios, including where hydrogen is considered**, in particular under the Hydrogen Superpower scenario
- **Consider the uptake of an adjacent lower cost hydrogen supply chain may significantly reduce anticipated volumes of electrification**, reducing the expense of addressing complexities arising from modelled levels of electrification, including under the Step Change scenario.
- **Flag that maintaining sufficient GPG capacity to ensure grid reliability is expected to require new GPG development across the coming decades** as GPG reliability supports much greater uptake of VRE generation.
- **Better investigate the role of existing technologies can ensure security of energy supply in a Net Zero NEM** and could be used if 'potential' advanced inverters with grid-forming capabilities do not eventuate.

2024 ISP (and associated activities) Recommendations

- **All scenarios to consider hydrogen and other renewable gases within the ISP gas model** as energy solutions which have the potential to provide a lower cost alternative to electrification of gas and transport energy demand. This would include implications for how much bolstering of the NEM will be required to facilitate lower anticipated levels of electrification following higher uptake of hydrogen and other renewable gases, as well as reductions in the levels of grid storage required following broad access to lower cost hydrogen pipeline energy storage.
- **All scenarios considering hydrogen and other renewable gases to consider hydrogen energy transport and storage via pipeline**, investigating Hydrogen Pathway 3 from Figure 54 of the IASR for both domestic and export applications as a matter of priority.

APGA considers there is sufficient evidence to be confident that effective consideration of hydrogen infrastructure options will show that improved outcomes are achieved when gas infrastructure is widely deployed in a large-scale hydrogen industry.

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[7] In anticipation of rebuttal, Hydrogen Electrolyzer technologies have been identified as technologically mature by the CSIRO in their 2019 Hydrogen Research, Development and Demonstration report https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-research

- **Include a ‘Plan A’ and ‘Plan B’ for ensuring NEM reliability** in scenarios with high reliance on DER and shallow battery storage for grid reliability purposes in order to mitigate the risk of these aspects undermining the broader generation basis of the scenario. Plan A should include proven, mature energy reliability solutions which exist today to ensure NEM reliability.
- **Include a ‘Plan A’ and ‘Plan B’ for ensuring NEM security** in scenarios with high reliance on ‘potential’ technologies in order to mitigate the risk of these technologies not coming to fruition. Plan A should include proven, mature energy security solutions which exist today to ensure NEM security.

We welcome further engagement with AEMO on the finalisation of the 2022 ISP and look forward to working more closely with AEMO towards a further step changes in electricity – gas system interaction ahead of the 2024 ISP.

To discuss any of the above feedback further, please contact APGA National Policy Manager Jordan McCollum on +61 422 057 856 or jmccollum@apga.org.au.

Yours Sincerely,

STEVE DAVIES
Chief Executive Officer
Australian Pipelines and Gas Association

Detailed Feedback

APGA appreciates the opportunity to engage with AEMO on the 2022 Draft ISP and seek to provide feedback across three topics:

- Changes since the 2020 ISP
- Potential for improvement within the Draft 2022 ISP
- Proposed actions ahead of the 2022 ISP and 2024 ISP

APGA hopes to engage further with AEMO on these topics and more in the leadup to the 2022 ISP delivery, and in the leadup to Draft 2024 ISP development.

1. Changes since the 2020 ISP

APGA has observed a range of improvements in AEMO's approach to ISP development since the 2020 ISP. Three key areas observed by APGA include how AEMO has approached:

- The pace of change in the Australian energy market
- The role of Gas Power Generation in the NEM
- The value of renewable gases in a net zero emission future

1.1. The pace of change in the Australian energy market

The rapid pace of change in the Australian energy market is clear. Acknowledging this pace of change is necessary for AEMO to ensure change can be best anticipated and managed.

By considering progressive scenarios within the ISP, AEMO stimulates further conversation, ambition, and activity. In doing so, AEMO contributes to energy industry development. APGA values the enhanced activity driven by AEMO's Hydrogen Superpower scenario and hopes that industry developments can lead to hydrogen and renewable gas increasingly feature in central scenarios of ISPs to come.

1.2. The role of Gas Power Generation in the NEM

GPG forms an important part of AEMO's reliability and security strategy in the Step Change scenario, with no reduction in GPG capacity before 2030 and an increase to over 9GW GPG Capacity by 2050. This need means that as old GPG retires, new GPG will need to be constructed to provide reliability and security to a high VRE NEM.

By supporting the reliability and security of the NEM, GPG ensures the lowest cost net zero NEM is achievable[8,9,10]. APGA supports the view put forward by AEMO's Nicola Falcon in RenewEconomy's Energy Insiders podcast, saying that *it's not economically efficient for*

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[8] Potential for Gas-Powered Generation to support renewables, Frontier Economics 2021 https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/210219_potential_for_gpg_to_support_renewables_-_final_report_0.pdf

[9] The role of gas in the transition to net-zero power generation, Frontier Economics 2021 https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/frontier-economics-report-stc.pdf

[10] Go for Net Zero, The Grattan Institute 2021 https://grattan.edu.au/wp-content/uploads/2021/04/Go-for-net-zero-Grattan-Report.pdf

[AEMO] to build that much more storage capacity just to better cover… …one or two periods in the year that it might be very, very high demand[11]. Nicola goes on to identify that *peaking generation of some sort, whether it's fuelled by natural gas in the future, whether it's fuelled by green hydrogen, or some other sort of zero carbon fuel, [AEMO] see it still playing a really crucial role in helping to balance the system*.

GPG today is a mature, high reliability form of dispatchable generation, ensuring that those regions which can reach high levels of VRE penetration are able maintain system reliability and security. It does so by combining GPGs fast start capabilities with the low-cost energy transport and storage via gas pipeline.

1.3. The value of renewable gases in a net zero emission future

AEMO's Hydrogen Superpower scenario provides insight into what is possible if renewable gases are developed alongside renewable electricity. Having the shortest time to achieve net zero and the greatest economic growth opportunity for the nation, the Hydrogen Superpower scenario indicates the potential of the growing renewable gas industry.

The Hydrogen Superpower scenario is an excellent start in considering a renewable gas future in Australia. Increased consideration of hydrogen in transport, hydrogen for heating and the role of gas infrastructure in a hydrogen industry are all likely to deliver further improved outcomes. APGA looks forward to working with AEMO to increase consideration of hydrogen and renewables gases in future ISPs.

The CSIRO places hydrogen technologies, including hydrogen electrolysers, fuel cells, internal combustion engines, and pipelines, all firmly at the highest Technology Readiness Level TRL 9. The technologies themselves are mature from a technical standpoint and are poised to deliver major cost reductions as the scale of deployment increases in the coming years.

2. Potential for improvement within the Draft 2022 ISP

APGA has identified a range of potential improvements which AEMO could apply to its current approach to 2022 Draft ISP development. Three key opportunities for improvement include:

- Analysis of hydrogen infrastructure
- Existing technologies offer predictable NEM reliability
- Existing technologies offer predictable NEM security

2.1. Analysis of hydrogen infrastructure

The Hydrogen Superpower scenario includes the earliest pathway to a net zero NEM and represents the greatest economic opportunity for the nation. This scenario currently only considers the use of electricity infrastructure to transport and store energy in a future

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[11] Transcript: Energy Insiders Podcast interview with Alex Wonhas, Energy Insiders Podcast, RenewEconomy 2021 https://reneweconomy.com.au/transcript-energy-insiders-podcast-interview-with-alex-wonhas/

hydrogen industry. This is highlighted in Section 3.12 of the IASR alongside a series of potential hydrogen pathways seen in Figure 54.

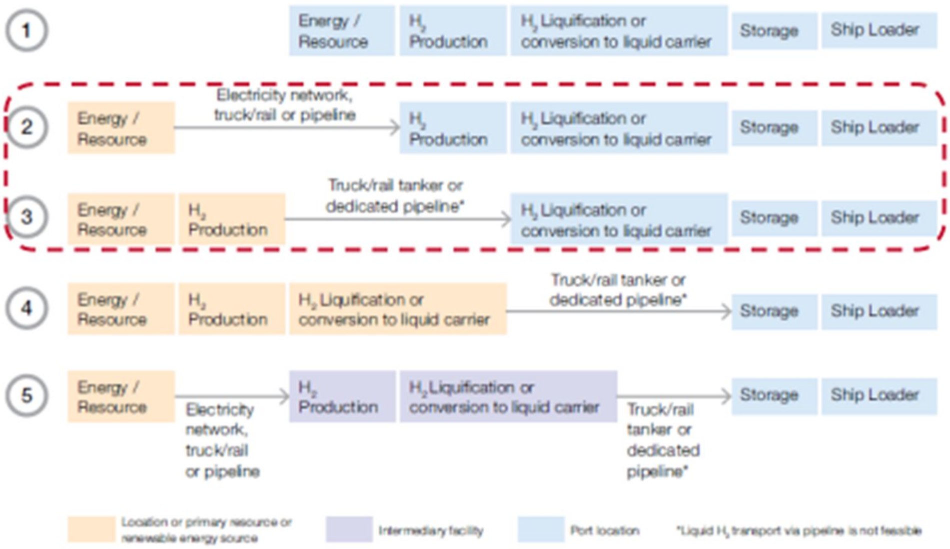

Figure 1: Figure 54 of the AEMO 2021 Inputs, Assumptions and Scenarios Report

Within this section of the IASR, AEMO goes on to note that *Pathway 3 may be explored in future ISPs*. Pathway 3 contemplates the production of hydrogen adjacent to the resources, and transporting hydrogen by truck, rail tanker or dedicated pipeline. APGA emphasises the importance of exploring the pipeline aspect of Pathway 3 through development of the 2024 ISP, both in the export context and the domestic context.

Today, pipelines transport more energy around Australia than electricity infrastructure does. In a study commissioned by APGA, GPA Engineering performed technoeconomic analysis comparing the cost of pipelines and powerlines across a series of like for like scenarios. APGA and GPA Engineering are releasing this report and an associated summary report in the week following the due date of the 2022 Draft ISP consultation process. APGA has attached pre-release copies of both documents to its submission in support of AEMO continuing to develop its understanding of hydrogen and gas infrastructure.

This analysis identifies that energy transport costs less via pipelines than via powerlines in every modelled scenario. Importantly, this included analysis of hydrogen pipelines too, which also transport energy at significantly lower cost than powerlines in all scenarios. Analysis spanned distances measuring from 25km to 500km and considered energy throughput capacities from 10 terajoules per day (116MW, 70t H2 per day) to 500 terajoules per day (5,800MW, 3,520t H2 per day) to ensure no factor was misinterpreted.

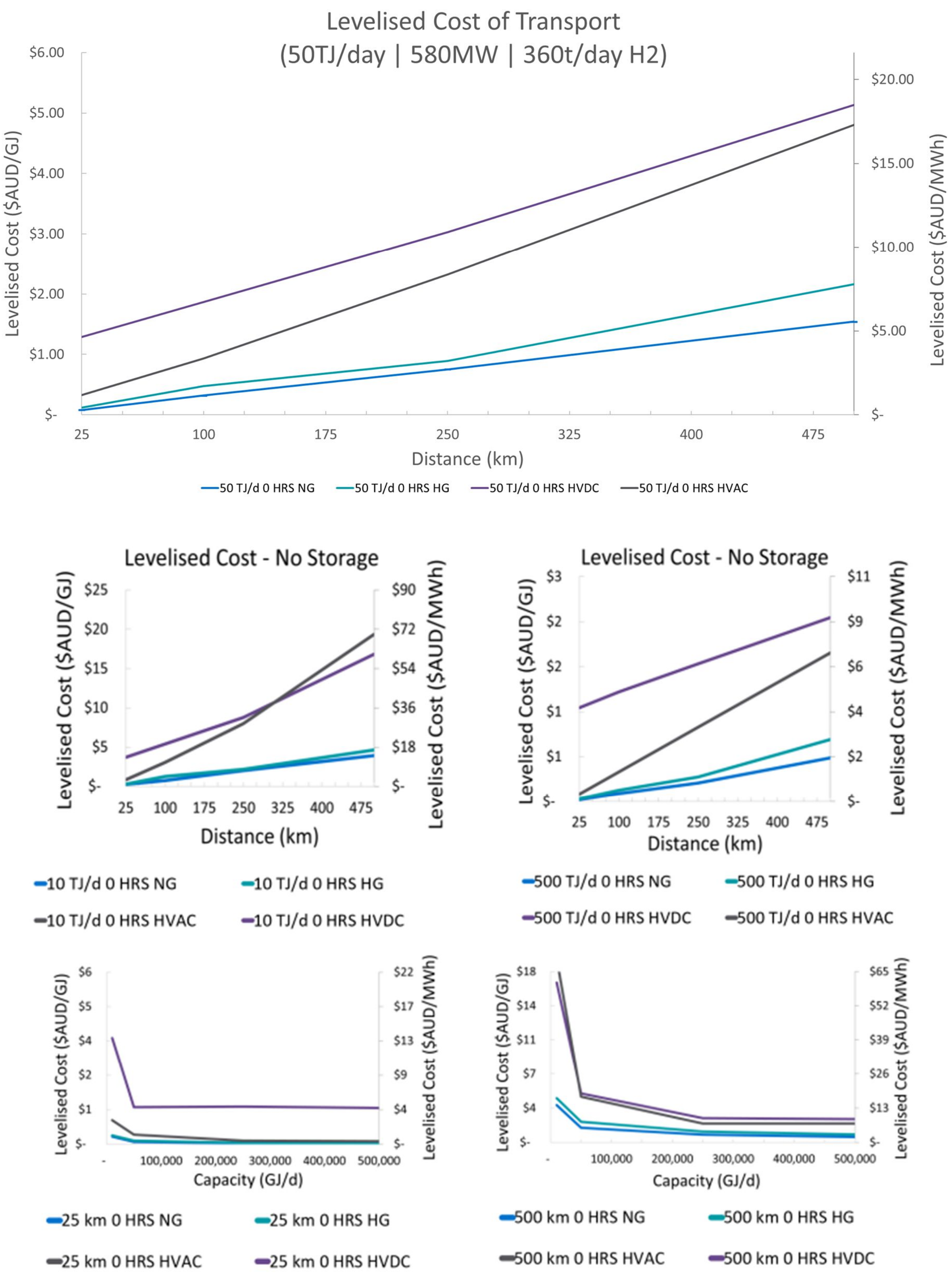

Figure 1: Levelised cost of transport (zeros storage) at throughput and distance extremes

Figure 2: Levelised Cost of Energy Transport data from Pipelines vs Powerlines report (attached)

The study also included analysis of the levelized cost of energy storage in pipelines, utility scale batteries and pumped hydro, showing once again that pipelines represent the lowest cost alternative. Storage volumes were assessed on an hours of design throughput basis, with 4hr, 12hr and 24hr energy storage intervals considered. Storing hydrogen in hydrogen pipelines was seen to cost 10’s to 100’s of times less than energy storage in batteries or pumped hydro across some scenarios.

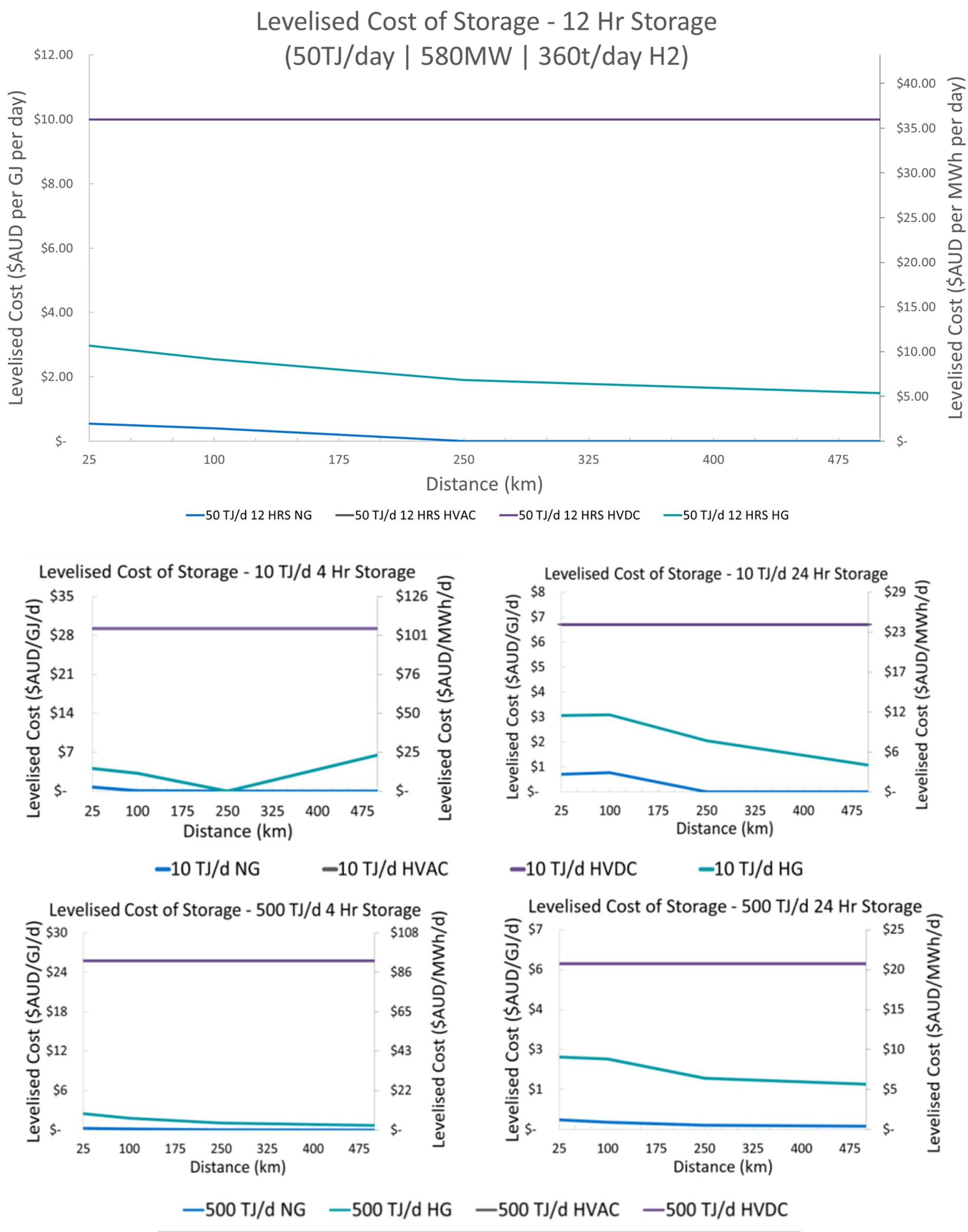

Figure 2: Levelised cost of storage (varying storage) for 10 and 500 TJ/d

Figure 3: Levelised Cost of Energy Storage data from Pipelines vs Powerlines report (attached)

While the lower prices are valuable, the energy supply chain implications of these costs combined with hydrogen production efficiencies are the real game changer for customer prices. As seen in the indicative comparable hydrogen value chains below, substantial reductions in hydrogen cost to customer can be achieved by transporting and storing energy via hydrogen pipelines. The opportunity to avoid transporting the energy lost through the electrification process gives hydrogen pipelines an even greater edge than their lower upfront cost alone.

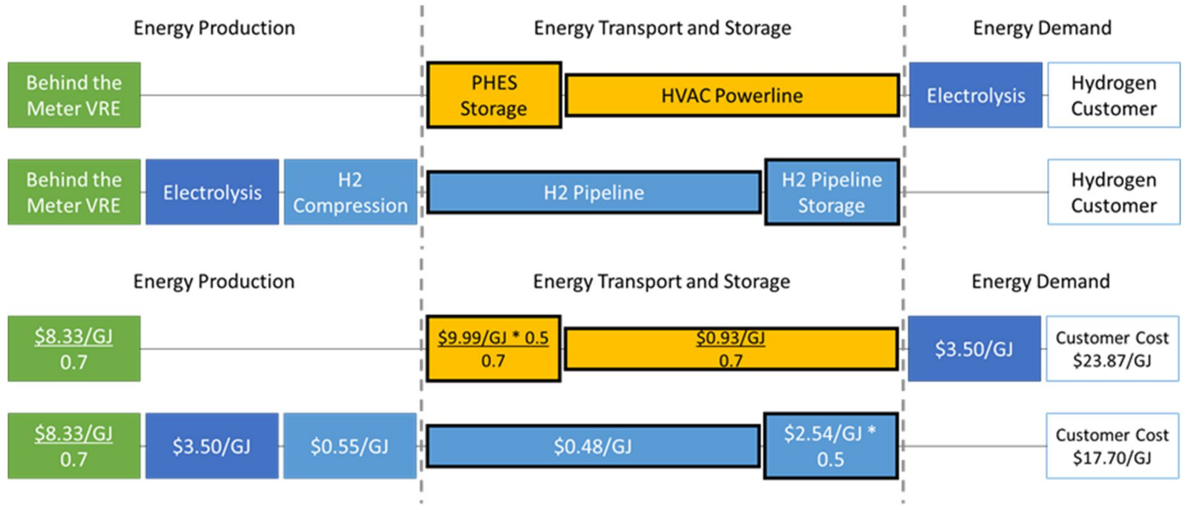

Figure 4: High level estimation of hydrogen cost for customer via example hydrogen supply chains

APGA recognises that there is a myriad of different hydrogen supply chain configurations. For some supply chains, energy cost for customers will be lower using pipelines, and for others, energy cost for customers will be lower using powerlines. APGA does not attempt to state that all energy transport should occur via pipelines. Rather, APGA anticipates that a balance of pipelines and powerlines will achieve the least cost energy system throughout Australia.

APGA looks forward to working with AEMO to ensure consideration of this information for future scenarios in the 2024 ISP.

2.2. Existing technologies offer predictable NEM reliability

When looking to the future of the NEM, the central scenario of the 2022 Draft ISP relies heavily on utility scale energy storage, distributed storage and DER. These options will be reliant on VRE generation via the very same market which they provide reliability for. APGA is concerned that these technologies may not always have the depth and certainty of energy availability provided by todays' market backed dispatchable generation options.

Mature technologies including GPG address grid reliability without the inherent risks of shallow energy storage options. They can do so in the future with a net zero outcome[10]. Whether fuelled by natural gas today (potentially decarbonised via offsets tomorrow) or supplied by renewable gas market in the future, GPG represents a deep, long-term solution to the challenge of reliability in a net zero NEM.

APGA has already noted above that AEMO sees a long-term role for GPG in the NEM. AEMO should consider maintaining deep dispatchable generation fuelled by secondary markets at or above the limit recommended within the Grattan Institute's Go for Net Zero report. The Grattan report proposes 10% dispatchable generation such as GPG (with offsets) alongside 90% variable renewable generation as the least cost approach to delivering a reliable net zero NEM. For reference, the 2022 Draft ISP central scenario sees firm dispatchable generation dropping below 10% by 2038-39 and below 6% by 2050.

Towards the top of the list of AEMO's priorities is the avoidance of blackouts across the NEM. AEMO know that mature technologies exist to secure grid reliability. APGA hopes that this knowledge combined with more progressive views around renewable gases and emissions offsets can lead to more reliable solutions to the NEM reliability challenge which lays in Australia's high VRE future.

2.3. Existing technologies offer predictable NEM security

Grid security within the NEM is one of the most crucial topics to get right in relation to Australia's net zero energy future. It is also one of the most complex topics, making it one of the hardest topics on which to have robust, public facing debate and discussion. There are three macro-level facts which can be stated about this challenge:

1. If sufficiently advanced grid forming inverters were to be developed and demonstrated to have sufficient fidelity to no longer require synchronous inertia within the NEM, this would be a boon for decarbonisation efforts globally and a huge leap forward in the global ability to achieve maximum possible VRE penetration in electricity markets;
2. Sufficiently advanced grid forming inverters are yet to be developed and demonstrated to have sufficient fidelity to no longer require synchronous inertia within the NEM;
3. Without sufficiently advanced grid forming inverters having been developed and demonstrated to have sufficient fidelity to no longer require synchronous inertia within the NEM, synchronous inertia is unequivocally required to ensure energy security within the NEM.

APGA know that system security is an AEMO priority, with significant work being undertaken throughout the Future Power System Security Program[12]. Improvements can be seen in overall NEM security, with recent improvements evident from the application of Primary Frequency Response measures[13]. Even after these improvements however, AEMO still regularly intervenes in the high Inverter Connected Generation (ICG) South Australia NEM

[12] Future Power System Security Program, Australian Energy Market Operator 2022 https://aemo.com.au/initiatives/major-programs/past-major-programs/future-power-system-security-program
[13] Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, Australian Energy Market Operator 2022 https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2022/pfr-implementation-report-v21-20-jan-22.pdf?la=en

Region[14]. Measures available to AEMO to date have been insufficient to fully secure the NEM without dispatching synchronous generation to physically provide synchronous inertia.

Despite this, and the availability of mature synchronous generation technologies, the central scenario of the 2022 Draft ISP identifies ‘potential’ advanced inverters with grid forming capabilities forming a key role in their future energy security strategy. Synchronous generation technologies such as GPG, whether fuelled by abated natural gas, hydrogen, or other forms of renewable gas, represent a here and now net zero solution to NEM security.

APGA considers that to great an emphasis has been placed on ‘potential’ advanced inverters and recommends that more emphasis be placed on existing options.

APGA provide additional commentary on two key subjects relevant to this section:

- Energy security case study: South Australia NEM region
- Relative technology maturity: Hydrogen and grid forming inverters

2.3.1. Energy security case study: South Australia NEM region

The South Australian NEM region has been Australia’s case study for an increasingly high VRE grid. The South Australian NEM region has had many renewable energy successes, including Australia’s first experience of VRE contributing 100% of South Australia’s net NEM region energy demand. That said, it is important to note that this has only been achieved on a net basis, and that behind every South Australian Net 100% VRE day lies support by a foundation of synchronous generation.

Since the system black event in 2016, AEMO have paid particular attention to energy security in this region, resulting in market intervention to ensure enough synchronous generation is maintained in the NEM region to ensure secure grid operation. While this has reduced over time, as a proportion of total generation, this has never reached zero. Analysis of total South Australian NEM generation across the past year displays that on no day did synchronous generation ever account for less than 17% of total NEM generation during this period. On each of the 21 days in which the South Australian NEM region could claim to have covered 100% of the state’s net electricity demand with renewable electricity, the quantity of electricity exports were either greater than or equal to the quantity of synchronous generation on the day.

[14] Directions to SA generator during billing weeks 37 to 40 2021 (and reports from previous periods), Australian Energy Market Operator 2022 https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports/directions-to-a-sa-generator-during-billing-weeks-37-to-40-2021

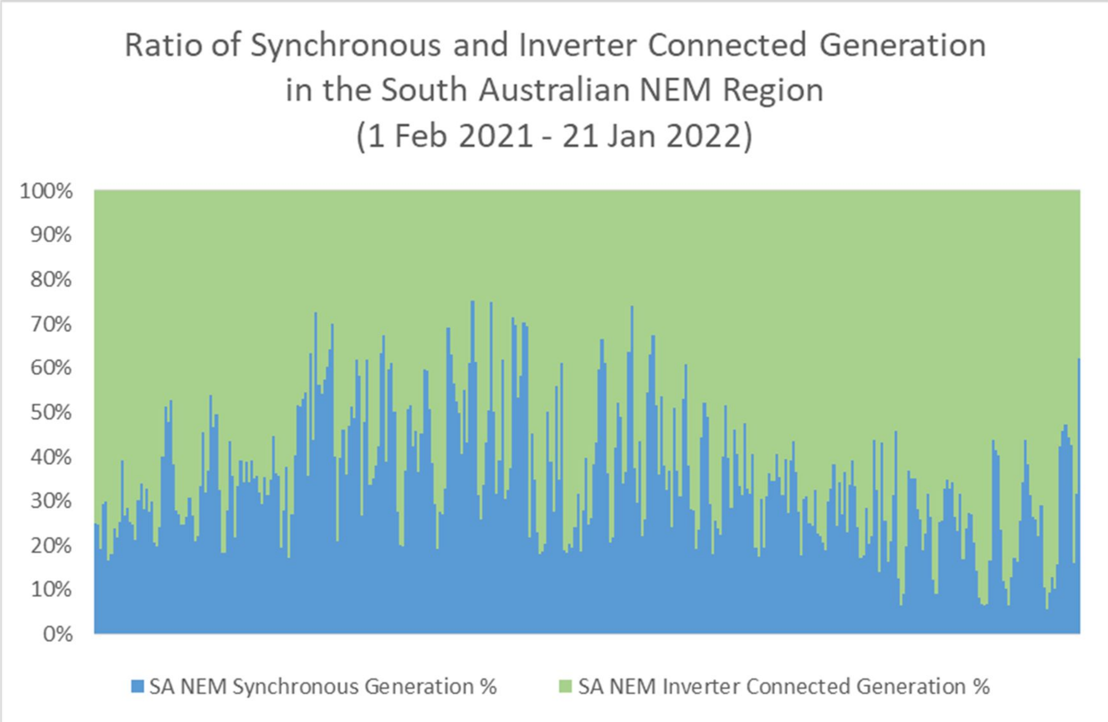

Figure 5: Ratio of Synchronous and Inverter Connected Generation in the South Australian NEM Region (1 Feb 2021 - 21 Jan 2022)[15]

This ratio is improving over time, and APGA congratulate all involved for reducing this ratio as much as possible. That said, it is clear that some level of synchronous inertia is required within the South Australian NEM region at all times. There are two mature technology approaches to the net zero emission provision this inertia, and one 'potential' approach:

a) Mature technology approach 1: Generating electricity through synchronous generation using carbon free or abated fuels
b) Mature technology approach 2: Using synchronous condensers as demand side inertia
c) 'Potential' technology approach: Using advanced inverters with grid forming capabilities

The challenge of energy security is demonstrated here through the South Australian example – a scenario which cannot cover 100% of net state energy demand without generating and exporting significant quantities of synchronously generated electricity. When planning for a secure, least cost net zero NEM, all pathways to providing energy security must be considered. A secure, net zero NEM could be achieved within the macro parameters of the central Step Change scenario through mature technologies, providing a greater chance of success for a 100% net zero NEM on a gross generation basis.

[15] OpenNEM Website
https://opennem.org.au/energy/nem/

2.3.2. Relative technology maturity: Hydrogen and grid forming inverters

Throughout this submission, APGA attributes the term 'potential' to advanced inverters with grid forming capabilities as the term 'potential' is used by AEMO in describing this technology[16]. In this white paper, AEMO notes:

With sufficient attention, focus, and investment, advanced inverter technology may be able to address many of the challenges facing the NEM today for the integration of renewable (inverter-based) resources. However, at present this potential is not demonstrated at the necessary scale, and focused engineering development is urgently needed to address the remaining issues and realise the promise of this technology.

APGA anticipates that hydrogen sceptics may attempt to draw parallels between the technological maturity of advanced inverters with grid forming capabilities and hydrogen technologies. APGA notes that such parallels, if drawn, would be inaccurate.

The 2019 CSIRO Hydrogen Research, Development and Demonstration report considers hydrogen technologies against the internationally recognised Technology Readiness Level (TRL) framework[17]. CSIRO puts hydrogen electrolysers, fuel cells, internal combustion engines, and pipelines all firmly at the highest ranking of TRL 9. Whilst cost reductions are still required to achieve more cost competitive hydrogen production and fuel cell utilisation, the technologies themselves are mature from a technical standpoint and can be deployed today.

Additionally, utility scale hydrogen production is occurring across the globe, with the current round of Australian hydrogen projects being developed on par with the worlds' largest hydrogen production facility in Japan[18],[19]. South Korea recently opened the world's largest hydrogen fuel cell power plant with a capacity of 78.96MW of dispatchable renewable generation capacity, while GE have been producing 100% hydrogen capable turbines for years[20],[21]. The technology required for 100% Hydrogen energy value chains are mature today, unlike that of a 100% synthetic inertia NEM.

More importantly however, such comparison is unfair on those striving to develop advanced inverters with grid forming capabilities. The challenges faced by a 100% ICG capable NEM and a 100% hydrogen energy value chain are very different. The technological development

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[16] Application of Advanced Grid-scale Inverters in the NEM, AEMO 2021
[17] Hydrogen Research, Development and Demonstration, CSIRO 2019 https://www.csiro.au/-/media/Do-Business/Files/Futures/hydrogen/1900534ENFUTREPORTHydrogenRDDFullReportWEB191129.pdf
[18] Over $100 million to build Australia's first large-scale hydrogen plants, ARENA 2021 https://arena.gov.au/news/over-100-million-to-build-australias-first-large-scale-hydrogen-plants/#:~:text=ARENA%20has%20been%20active%20in,hydrogen%20production%2C%20power%20to%20gas
[19] The World's Largest Hydrogen-Production Facility on the Path to Zero Emissions, JapanGov 2022 https://www.japan.go.jp/kizuna/2021/03/hydrogen-production_facility.html#:~:text=The%20world's%20largest%20facility%20for,Energy%20Research%20Field%20(FH2R).
[20] H2 View 2021 https://www.h2-view.com/story/new-78-96mw-hydrogen-fuel-cell-power-plant-opens-in-south-korea/
[21] Hydrogen fuelled gas turbines, GE 2022 https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines

of grid forming inverters is simply more difficult than producing, transporting, storing, and using hydrogen.

3. Proposed actions ahead of the 2022 ISP and 2024 ISP

In light of changes identified since the 2020 ISP and potential for improvement within the Draft 2022 ISP, APGA proposes a range of actions through which AEMO could greatly improve ISP development. In recognition of the limited time ahead of 2022 ISP delivery, APGA recommends AEMO undertake more achievable actions ahead of the 2022 ISP, alongside more involved actions which AEMO could take ahead of the 2024 ISP.

3.1. Pre 2022 ISP

APGA proposes that AEMO prioritise ensuring that the Australian energy industry and general public are adequately and accurately informed of certain truths within the 2022 ISP.

Recognise that energy transport and storage by pipeline could result in lower cost, lower complexity scenarios, including where hydrogen is considered

As discussed in Section 2.1 of its submission, APGA identifies that by only considering electricity transmission and electricity storage technologies, the current version of the Hydrogen Superpower scenario misses out on the opportunity of lower cost hydrogen pipeline transport and storage. By utilising hydrogen infrastructure in place of electricity infrastructure, AEMO could achieve a lower cost, lower complexity solution for both the NEM and the broader Australian energy system under this scenario.

APGA propose that AEMO note within the 2022 ISP that the cost and complexity found within the Hydrogen Superpower scenario may be able to be reduced through the utilisation of hydrogen pipeline infrastructure as contemplated in hydrogen pathway 3 seen in Figure 54 of the IASR.

Consider the uptake of an adjacent lower cost hydrogen supply chain may significantly reduce anticipated volumes of electrification

Large-scale electrification within AEMO scenarios leads to an increase in NEM complexity in order to address larger variations in NEM supply and demand. This is seen to require significant infrastructure investment, at significant cost, including in the Step Change scenario. Much of the complexity caused by mass electrification could be avoided through the uptake of an adjacent, potentially lower cost hydrogen supply chain. This is not yet considered in AEMO's scenarios beyond the Hydrogen Superpower scenario. The Inclusion of large-scale hydrogen uptake may significantly reduce the currently anticipated volume of electrification, and as such, the expense of addressing the complexities which arise from the anticipated volume of electrification.

APGA propose that AEMO note within the 2022 ISP that the complexities caused by assumed levels of electrification seen in the Step Change and other scenarios may be reduced if a parallel hydrogen energy supply chain develops. Such an outcome would avoid much of the costly investment required to upgraded then NEM to meet all energy demand in a full electrification future.

The need for new GPG development to ensure the reliability of a high VRE NEM
After past ISPs proposed reductions in GPG capacity, new GPG development required to maintain sufficient GPG capacity under the Step Change scenario may be controversial. Investors and financiers alike will need certainty to combat incorrect views that no further GPG investment is required in the NEM.

APGA proposes that AEMO note within the 2022 ISP that the levels of GPG required to maintain grid reliability under the Step Change scenario will require further investment in new and repurposed GPG across the coming decades.

Existing synchronous generation technologies will be needed ensure grid stability if 'potential' advanced inverters with grid-forming capabilities do not eventuate

The Step Change scenario relies upon 'potential' advanced inverters with grid-forming capabilities, not contemplating how AEMO would ensure NEM security if such technologies do not eventuate. In this event, APGA anticipates that AEMO would need to propose investments in traditional, mature technologies to maintain energy security. Without prior advice of this necessity, such investments to secure grid security may receive opposition, impeding timely and cost-effective deployment, ultimately risking the energy security of the NEM.

To mitigate this risk, APGA proposes that AEMO note within the 2022 ISP that traditional, mature technologies would need to be deployed to ensure energy security within the NEM in the event that 'potential' technologies advanced inverters with grid-forming capabilities do not eventuate.

3.2. Pre 2024 ISP

In the leadup to the 2024 ISP, APGA proposes the following changes in AEMO development of the ISP:

- All scenarios to consider hydrogen and other renewable gases within the ISP gas model as energy solutions
- All scenarios considering hydrogen and other renewable gases to consider hydrogen energy transport and storage via pipeline
- A 'Plan A' and 'Plan B' for ensuring NEM reliability
- A 'Plan A' and 'Plan B' for ensuring NEM security

All scenarios to consider hydrogen and other renewable gases within the ISP gas model

The opportunity for renewable gases such as hydrogen and biomethane to compete with electrification will impact the economic validity of all scenarios, not just the Hydrogen Superpower scenario. APGA recognises that the Hydrogen Superpower scenario was AEMO's important first foray into considering renewable gases acting alongside renewable electricity in a net zero future, but not contemplating their broader impact in future ISP scenarios risks inefficient over investment in the NEM. Australian energy customers will opt for the least cost net zero energy option regardless of whether there is inefficient over investment to enable all energy to pass through the NEM.

Inefficient over investment in electricity infrastructure in the NEM has been seen in the past to result in unnecessarily higher energy costs for Australian homes and businesses[22]. AEMO has an obligation to consider the impacts of a future in which renewable gases compete with renewable electricity to ensure inefficient over investment can be avoided.

APGA proposes that all scenarios considered under the 2024 ISP include consideration of potential renewable gas uplift through to 2050 in order to demonstrate the levels of electrification and associated NEM complexity which could be avoided through renewable gas uptake. While this is preferred to occur through all scenarios, APGA could understand a reluctance to significantly modify 2022 scenarios ahead of 2024. In this case, as a minimum APGA proposes that a "Diverse Step Change" scenario be considered in which renewable gases grow along a similar trajectory experienced by renewable electricity across the past decades.

AEMO has at least 18 months to prepare for the 2024 ISP. APGA expects that this would be sufficient lead time for AEMO to develop the necessary capability to apply greater consideration to renewable gases ahead of the 2024 ISP. APGA notes that the Future Fuels CRC is researching and developing integrated electricity and gas system models that could be of use to future ISPs.

All scenarios considering hydrogen and other renewable gases to consider hydrogen energy transport and storage via pipeline

Alongside the opportunity for renewable gases to compete with electrification, the opportunity for lower cost pipeline infrastructure to compete with electricity infrastructure will impact the economic validity of all scenarios in which renewable gases are considered. Preparing for all energy destined for electrolysis to pass through the NEM under the Hydrogen Superpower scenario (or any future scenario) risks inefficient over investment in the NEM. Hydrogen producers will seek the least cost pathway to market regardless of whether inefficient over investment in the NEM occurs, and Australian renewable gas customers will opt for the least cost net zero energy option regardless of whether inefficient over investment occurs as well.

Inefficient over investment of electricity infrastructure in the NEM has been seen to result in unnecessarily higher energy costs for Australian homes and businesses in the past[22] above. AEMO has an obligation to consider the impacts of a future in which renewable gases compete with renewable electricity to ensure inefficient over investment can be avoided.

APGA proposes that the 2024 ISP consider the utilisation of lower cost pipeline infrastructure where renewable gases are considered within the energy system, in particular with relation to hydrogen pipelines. APGA anticipates that the integration of lower cost pipeline infrastructure into the broader Australian energy system will lead to an overall lower cost energy system, much like gas pipelines allow for today.

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[22] Cut energy bills by ending gold-plated investment, The Grattan Institute 2018 https://grattan.edu.au/news/cut-energy-bills-by-ending-gold-plated-investment/

A ‘Plan A’ and ‘Plan B’ for ensuring NEM reliability

Ensuring energy reliability in the NEM is a key deliverable of the ISP. APGA recognises that a future in which low reliability forms of dispatchable generation dominate reliability in the NEM is a possible future which needs to be prepared for. AEMO also needs to be prepared for a future in which distributed storage, DER and shallow utility scale storage are insufficient to ensure reliability in the NEM. AEMO are highly experienced in the application of mature technologies which are able to ensure energy reliability in the NEM and have the opportunity to provide a ‘Plan A’ and ‘Plan B’ for NEM reliability.

APGA proposes that AEMO develop a ‘Plan A’ and ‘Plan B’ for at least its central scenario to ensure the necessary actions required to ensure NEM reliability are taken in the event that current proposed options do not eventuate. Through such an approach, ‘Plan A’ would represent the no-risk approach to ensuring NEM reliability, using mature net zero emission technologies made deeply dispatchable via the support of large reliable energy markets. ‘Plan B’ could then focus on ensuring NEM reliability through shallow battery storage, distributed storage, and DER solutions in preparation for the event that this outcome unfolds.

A ‘Plan A’ and ‘Plan B’ for ensuring NEM security

Ensuring energy security in the NEM is a key deliverable of the ISP. APGA recognises that a future in which ‘potential’ advanced inverters with grid-forming capabilities ensure security in the NEM is a possible future which needs to be prepared for. AEMO also needs to be prepared for a future in which these technologies do not eventuate. AEMO are highly experienced in the application of mature technologies which are able to ensure energy security in the NEM and have the opportunity to provide a ‘Plan A’ and ‘Plan B’ for NEM security.

APGA proposes that AEMO develop a ‘Plan A’ and ‘Plan B’ for at least its central scenario to ensure the necessary actions required to ensure NEM security are taken in the event that ‘potential’ advanced inverters with grid-forming capabilities do not eventuate. Through such an approach, ‘Plan A’ would represent the no-risk approach to ensuring NEM security, using mature net zero emission technologies which are able to provide physical synchronous inertia. ‘Plan B’ could then be founded upon ensuring NEM security via ‘potential’ advanced inverters with grid-forming capabilities.

Attachment 1: Pipelines vs Powerlines: a summary

Pipelines vs Powerlines: a summary

Least-cost energy transport and storage in a net zero future

Pipelines vs Powerlines: Reviewing Energy Transmission

256 case map

Transmission distances
25km → 500km

Throughput capacities
10 TJ/day → 500 TJ/day

Storage scenarios
4hr, 12hr, 24hr

Hydrogen Pipeline
Natural Gas Pipeline
Vs.
HVAC Powerline
HVDC Powerline

A techno economic comparison of Australian energy transmission infrastructure, covering natural gas pipelines, gaseous hydrogen pipelines, HVAC and HVDC power lines.

Reliability of supply

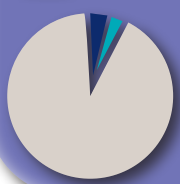
39,000 km of high pressure gas pipelines

0.03 events per 1000km a year loss of supply

43,000 km of high voltage power lines

0.42 events per 1000km a year loss of supply

Energy Storage



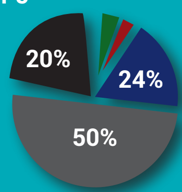
Electricity
0.017 TWh

Gas Pipelines
2.3 TWh

Underground Gas Storage
64.3 TWh

End Use Energy

Electricity 858 PJ
- renewables 194 PJ
- coal & oil 485 PJ
- gas 179 PJ



Coal 102 PJ
Gas 1,012 PJ
Renewables 170PJ
Refined Products 2,125 PJ

Energy transport through **pipelines** is up to **5 times more cost effective** than **energy transport** via **high voltage powerlines**

4hr energy storage often comes at **no additional cost** when using typical pipeline construction principles

Energy storage in **pipeline linepack** can be **100s** of times more **cost effective** than **utility scale battery** and **pumped hydro energy storage**

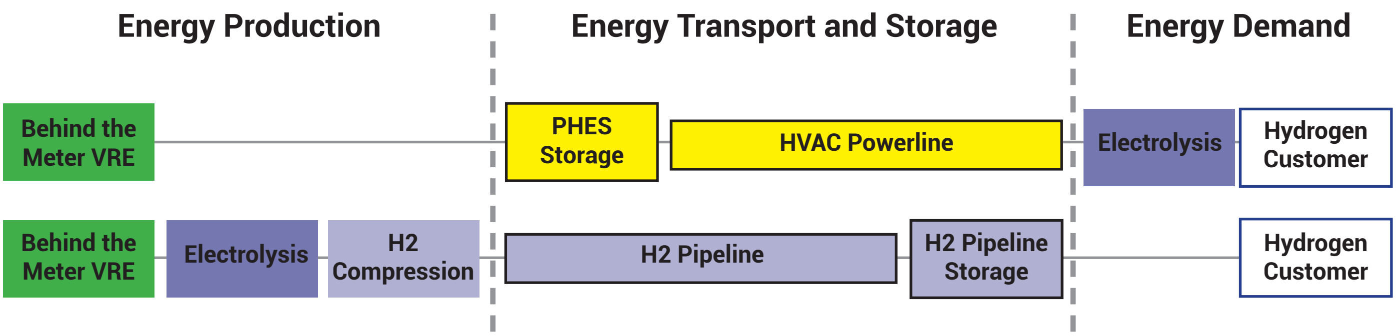
All cases modelled in this report show that energy transport and storage via hydrogen or natural gas pipeline is more cost effective than electricity transport and storage in all scenarios.

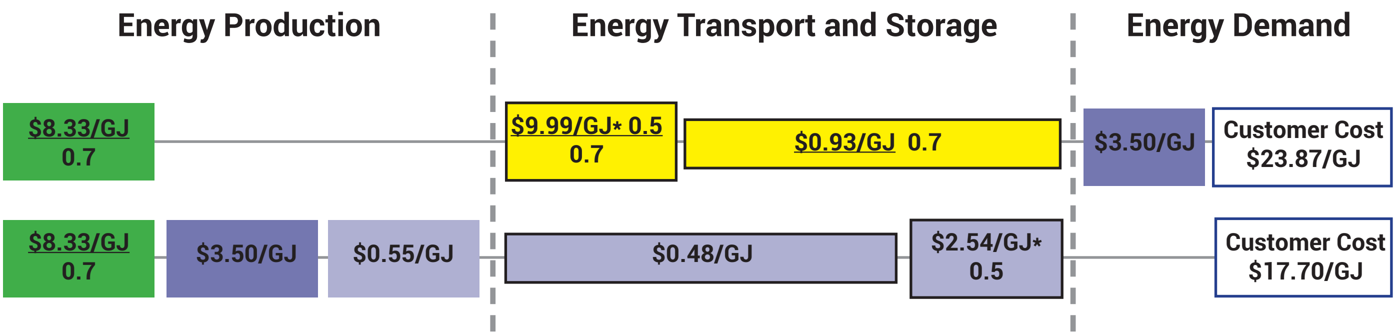
Introduction

The cost and reliability of energy transport and storage infrastructure is a crucial issue in the energy industry, with implications for energy access, affordability, the environment and public safety. APGA commissioned GPA Engineering to produce a report to analyse the cost of energy transport and storage across a range of different gas and electricity infrastructure options. This summary document uses data from the full report (available here [link]) to provide the information in a way that can inform all readers.

As part of the GPA analysis says to date, pipelines have been a lower cost form of energy transport compared to powerlines. The track record of pipeline infrastructure shows that it is more reliable and more environmentally friendly than electricity infrastructure.

As the Australian transition to net zero-energy ramps up, a sound understanding of the whole energy system, including energy transport and storage infrastructure, will ensure the least cost decarbonisation outcomes for the nation. Recognising this, APGA sought technoeconomic analysis looking at the historical and anticipated costs of pipelines and powerlines over a range of energy capacities, distances and quantities of energy storage. Cases span distances of 25km to 500km, energy throughput of 10 terajoules a day (TJ/day) to 500TJ/day, (equal to 116 megawatts (MW) a day to 5800MW/day or 70 tonnes of hydrogen a day to 3520t H2/day). Also studied were energy storage quantities of 4 hours, 12hr and 24hr of transport throughput capacity.





Through this analysis, GPA Engineering has identified that energy transport via hydrogen pipeline costs up to four times less than via powerlines when comparing like for like distance and capacity scenarios. Further, energy storage in hydrogen pipelines costs up to 37 times less than battery energy storage systems (BESS) and up to 10 times less than pumped hydro energy storage (PHES). These figures are even greater for methane pipelines, making energy transport and storage or renewable sources of methane more cost effective than renewable sources of hydrogen.

From the perspective of a hydrogen customer, these cost improvements aren't the only advantage of hydrogen pipelines. Hydrogen production can be collocated with the energy producer enabling access to lower cost energy to power electrolysis. This also allows for the energy consumed by electrolysis to be consumed before energy transport and storage, additionally reducing the cost of hydrogen to customers by around 30 per cent.

APGA acknowledges that different renewable gases are produced at different pressures and, as such, require different compression solutions. Different compression solutions will increase hydrogen production costs by different amounts relative to the production process in much the same way as experienced in natural gas production today. Neither this nor the cost of HVAC inverter connection were covered in broad detail in this study, instead they were considered within production scope as is the standard when costing energy production today.

Despite this, the gas infrastructure solution delivers hydrogen at 20 percent lower cost than the electricity infrastructure solution. This helps to demonstrate that customer outcomes are highly dependent on a range of costs and efficiencies spanning production, energy transport and storage, as well as end use. The opportunity for pipeline infrastructure and, in particular, hydrogen infrastructure, to provide a lower cost energy transport solution could play a significant role in Australia's least-cost net-zero energy future.

In publishing this information, APGA and GPA Engineering do not seek to make a case for all energy to be transported via hydrogen pipelines in a net-zero future. Instead, we seek to open the conversation about least-cost energy infrastructure to create a future in which a blended energy infrastructure system of pipelines and powerlines can deliver least-cost net-zero energy for Australian households, businesses and export industries.

For more information, please contact apga@apga.org.au

Steve Davies
APGA Chief Executive Officer

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Australia's complementary energy infrastructure systems

Australia has two parallel and complementary energy infrastructure systems supplying energy to households and businesses. The National Energy Market (NEM), Western Energy Market (WEM) and other electricity infrastructure deliver a combined 20 per cent of all end-use energy consumed in Australia. Australia's gas infrastructure builds on this, delivering 28 per cent of all end-use energy consumed in Australia, including fuel for the gas power generators (GPG) supplying 21 per cent of electricity demand.[1]

These systems work hand in hand. Today's gas system supplies cheap, reliable energy to households and businesses across the nation, it absorbs the seasonal variations in energy demand which reach far above total NEM capacity and it supports the NEM in periods of short-term high demand through providing GPG fuel supply.

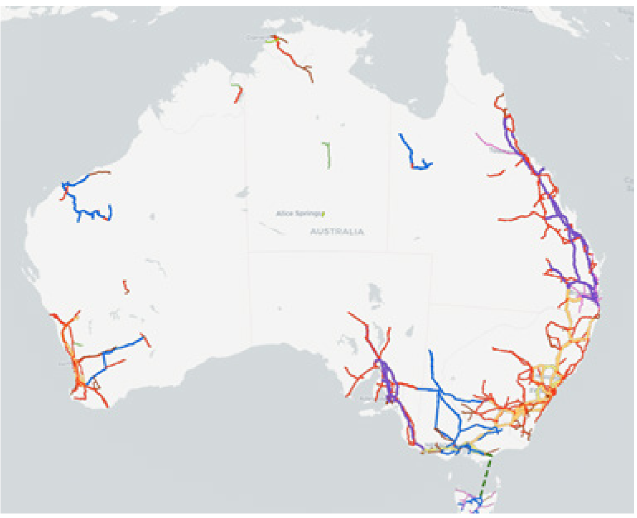
A range of applications are suited to using energy in both electrical and gaseous forms, and there are some applications more suited to one or the other. Both energy systems are on a decarbonisation journey. While the electricity system is more advanced in its journey at this point, Gas Vision 2050 sets out the ways that Australia's gas system is set to achieve net-zero emissions by 2050.

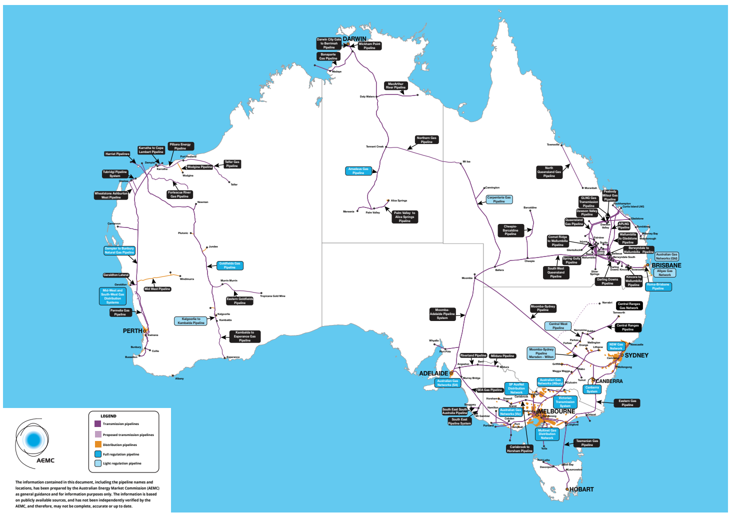
The role and advantages of gas infrastructure are critical to Gas Vision 2050 being achieved. Gas infrastructure is resilient, experiencing far fewer outages than electricity infrastructure. Gas infrastructure is buried underground, making it less likely to be impacted by weather.

Today, in Australia, more energy is transported and stored through gas infrastructure than through electricity infrastructure. This is predominantly due to gas infrastructure's ability to deliver energy transportation and storage services flexibly, reliably and at a comparatively lower infrastructure cost.

How does gas infrastructure do this?

Pipelines can move and store energy due to the physical characteristics of gas molecules. These physical characteristics are the same for all gases, while gas is often used interchangeably with natural gas, the term applies to all gases. Gases have no fixed shape and no fixed volume, they expand freely to fill whatever container they are in. They are highly compressible, meaning you can increase pressure and fit more in – this makes them easy to move and store. Gases are stable, making them easy to store over long periods of time. Pipelines, being long tubes, can hold large quantities of gas. By pressurising the pipeline, very large quantities of gas can be moved and stored relatively simply.





Lower historical cost of energy transport via pipeline than via powerline

Pipelines have long been used as a low-cost way to get energy to customers, with infrastructure extending directly to homes and businesses. Power stations are positioned relative to electricity infrastructure and demand to minimise electricity transmission costs, with pipelines used to transport fuel to GPG within the NEM.

Directly comparable examples of pipelines and powerlines are rare. However, one example is the comparison between regulated electricity and gas transmission and distribution infrastructure in the Victorian energy market.

Table E2: Costs and deliveries of Victoria's energy infrastructure (2019)

Transmission and Distribution Infrastructure	Regulated Asset Base ($m)	Actual Annual Revenues ($m)	Actual Energy Delivered (GWh)	Max Demand Capacity (MW)
Electricity	17,329	2,825	41,480	8,864
Gas	5,631	774	64,722	23,250

In comparing the regulated asset bases (RABs) of these parallel energy infrastructure pathways, we find the following:

- Victorian gas infrastructure delivers a third more energy than Victorian electricity infrastructure.
- Victorian gas infrastructure can support peak demand 60 per cent higher than Victorian electricity infrastructure.
- Victorian gas infrastructure generates only 27 per cent of the revenue from customers compared to Victorian electricity infrastructure.
- Victorian electricity infrastructure RAB value (the value of infrastructure) is three times more than Victorian gas infrastructure RAB.

While not a perfect like-for-like comparison, this example provides an indicative example of cost effectiveness of electricity and gas infrastructure with similar levels of energy demand within a specific region. In this example, gas infrastructure is clearly a more cost-effective form of energy transport than electricity infrastructure.

Pipelines are more reliable and have less local impact than powerlines

Reliability

Energy reliability is a key challenge faced by decarbonising energy markets, with variable renewable electricity (VRE) generation introducing new sources of instability in decarbonising electricity networks. While NEM reliability impacts of VRE have been minimal to date, Australian gas pipeline infrastructure has been more reliable than Australian electricity transmission infrastructure over the past decade.

The reliability of energy infrastructure can be considered in terms of loss of supply incidents per 1000km per annum. Over the past decade, gas pipelines demonstrate superior reliability when compared to high voltage transmission lines on this basis.

Table 3: Loss of Supply Comparison between Gas Transmission Pipelines and Electricity Transmission Powerlines

Infrastructure	Period of Review	Approximate length	Loss of Supply Events	Event per annum (average)	Events per annum per 1000 km installed
Gas pipelines	9 years (2009-2018)	39,000	10 (9 leaks, 1 rupture)	1.1	0.03
HV Powerlines	9 years (2010-2019)	43,000	164	18.2	0.42

Impact on local habitats, landholders, and communities

Pipelines also have lower impacts on the local habitats, landholders, and communities where they are installed and operate. The bushfire risk, land use impacts and visual pollution brought by above-ground powerlines is much greater than that of pipelines.

This is because the Australian gas pipeline industry buries its pipelines, increasing safety and visual amenity, and allowing a greater level of land use opportunities for landholders and communities with pipeline right of ways passing through their land. As a result, pipeline infrastructure is afforded greater social licence than powerlines, generally going unnoticed once installed.

The impact of above-ground powerlines can be greatly lessened by installing below-ground powerlines. Unfortunately, below-ground powerlines cost more than overhead powerlines, having been estimated at around five to six times the cost of above-ground powerlines in a recent study[2]. Due to this, only costs of above-ground powerlines have been considered in the GPA Engineering report in order to avoid unnecessary additional cost influencing the results of the report.

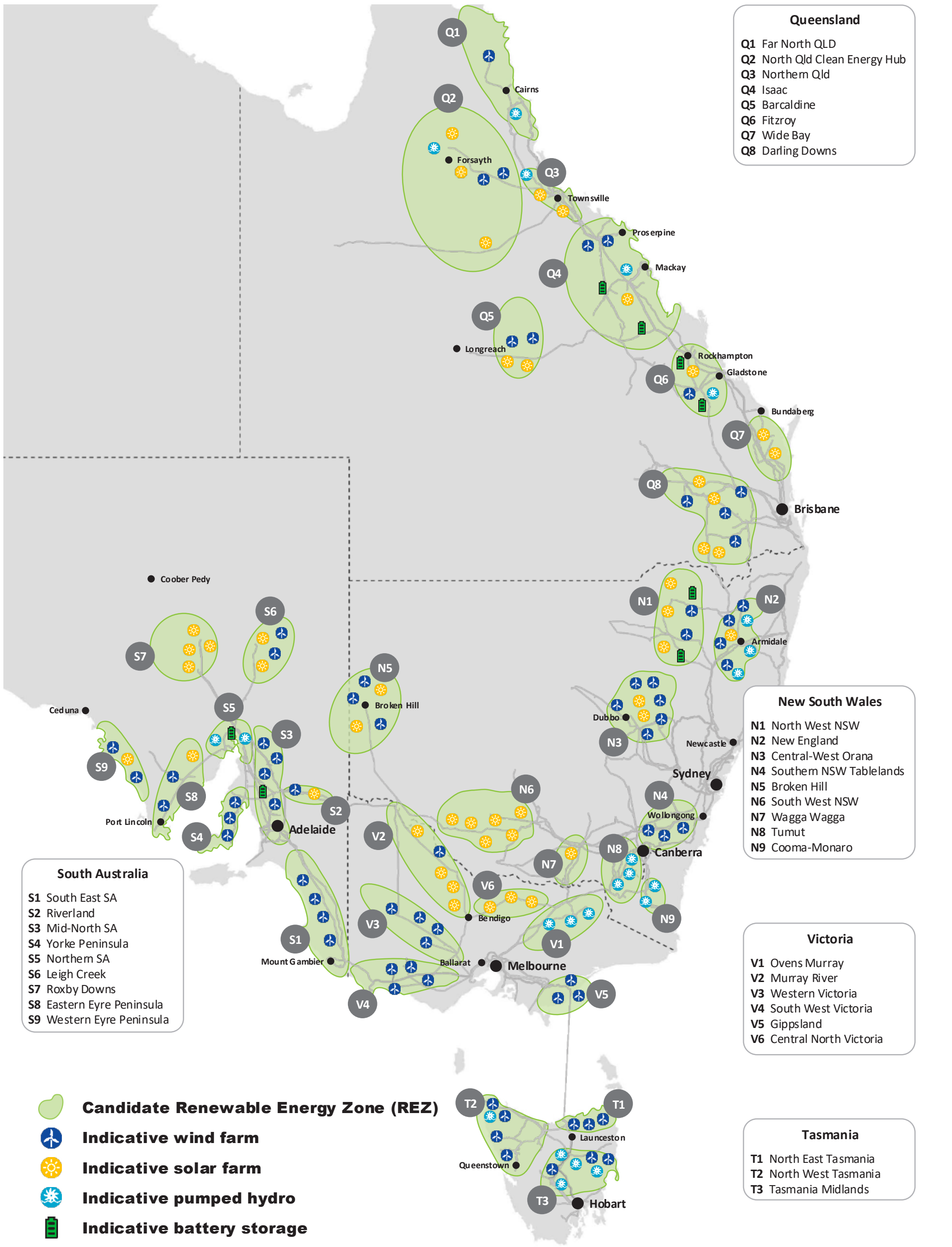
Powerline ROW, Pipeline ROW, Farmer's paddock with pipeline running through

Australian ramp up towards a net zero-energy system

The Australian energy industry has seen in increasingly rapid pace of change towards a net zero energy future. This has been recognised by the Australian Energy Market Operator through use of its Step Change scenario as the central scenario in the 2022 Integrated System Plan and responded to by the federal government through the creation of Renewable Energy Zones.

AEMO anticipates an accelerated decarbonisation of Australia through its Hydrogen Superpower scenario, forecasting that a full-scale hydrogen industry can deliver a net-zero NEM a decade earlier and with greater economic growth than options without hydrogen.

These hydrogen plans, alongside many others, consider energy transport and storage only via electricity. This is despite the fact there are many characteristics of gas infrastructure that suggest its the wide-spread use can deliver a lower cost renewable gas industry and pathway to decarbonisation.



REZs from 2022 Draft ISP (© statement) [3]

To consider this possibility, APGA commissioned GPA Engineering to deliver Pipelines vs Powerlines – A Technoeconomic Analysis in the Australian Context. In this report, technoeconomic comparisons of the cost of energy transport and storage were undertaken for natural gas (NG) pipelines, hydrogen (H2) pipelines, high voltage alternating current (HVAC) powerlines, and high voltage direct current (HVDC) powerlines. A summary of the results of this report can be seen in the following pages.

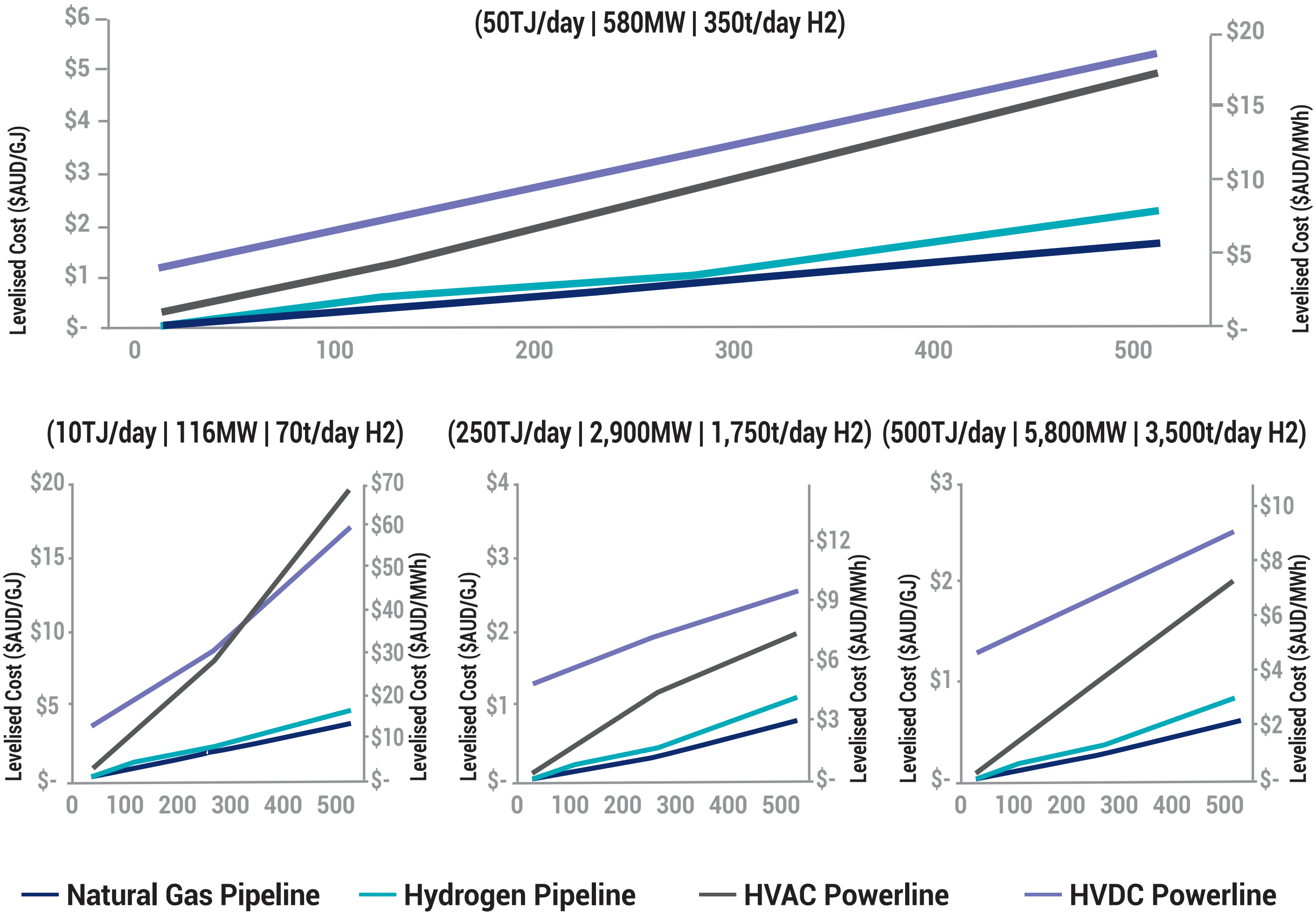
Energy transport via new pipelines costs less than energy transport via new powerlines

Technoeconomic analysis by GPA Engineering shows that while hydrogen pipelines do cost more than natural gas pipelines, both cost significantly less than energy transported via either HVAC or HVDC powerlines.

This result was seen across all modelled scenarios. The study considered energy transport distances between 25km and 500km, and energy transport capacity as low at 10 terajoules per day to 500TJ/day, 9equal to 116 megawatts (MW) a day to 5800MW/day or 70 tonnes of hydrogen a day to 3520t H2/day).

APGA had expected to observe a crossover point over the distance and capacity ranges where powerlines may have become more cost-effective than powerlines, but this was not observed. This implies that if a crossover does exist, it is outside of the range of distances and capacities modelled. HVDC costs appear to converge with H2 PPL costs with increased distance in the 10TJ/day scenarios, but the trajectory from cases analysed puts the crossover well above the maximum end of study range.

Levelised Cost of Transport



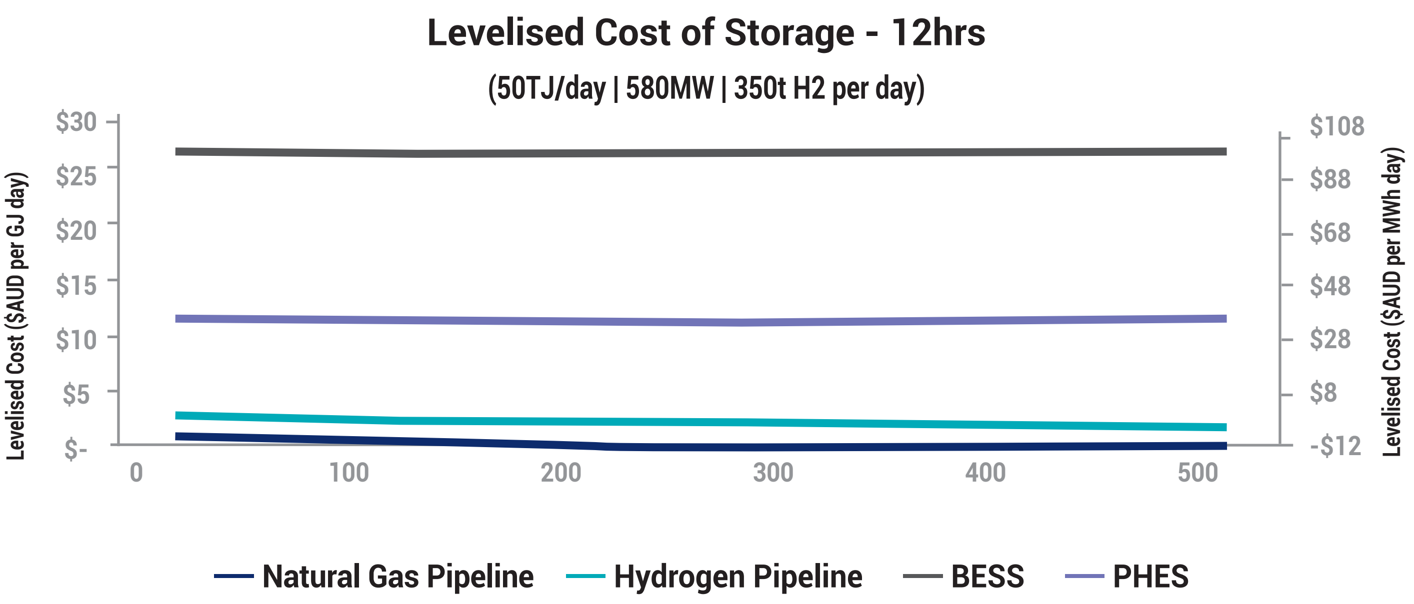
Energy Storage in new pipelines costs less than energy storage in BESS or pumped hydro

Due to the compressible nature of gases, pipelines transporting gases such as hydrogen and methane can store gas in the same pipeline at the same time as it is used to transport the gas to customers.

Designing a new pipeline to store a quantity of gas simply requires an increase in pipeline diameter once the pipeline diameter required to transport the gas is known. The additional cost of increasing pipeline diameter is the cost attributable to energy storage in pipelines, making the costs significantly less than bespoke energy storage technologies.

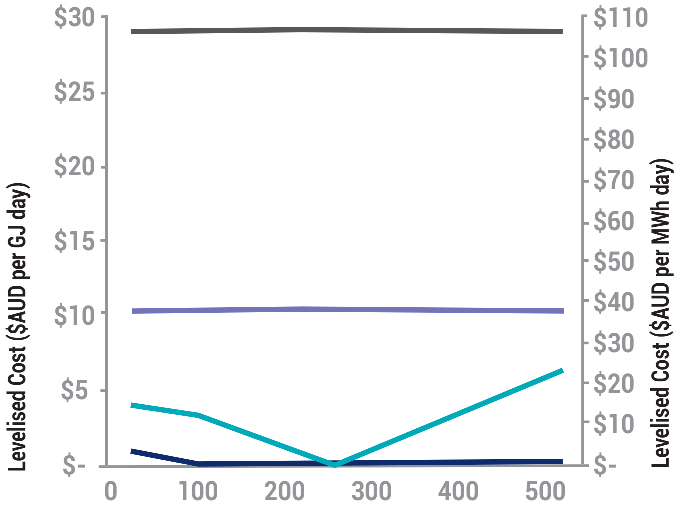
To compare the cost of pipeline energy storage with battery energy storage systems (BESS) or pumped hydroelectric energy storage (PHES), the additional cost to increase pipeline diameter was analysed over a range of energy storage cases. Storage cases were designed relative to energy transport capacity, targeting 4hrs, 12hrs and 24hrs of storage.

Non-zero pipeline energy storage costs span between $0.03 and $6.47/per GJ per day, or $0.11 to $23.29 per MWh per day. This is compared to PHES costs as low as $5.80 per GJ per day or $21 per MWh per day, and BESS costs as high as $29.23 per GJ per day or $105 per MWh per day. This makes energy storage costs in pipelines10s to 100s of times lower than electricity storage in BESS (x) and PHES (y). In some cases, 4hr energy storage in pipelines reaches $0 per gigajoule as typical pipeline size increments are already large enough to enable 4hrs worth of gas or hydrogen storage.



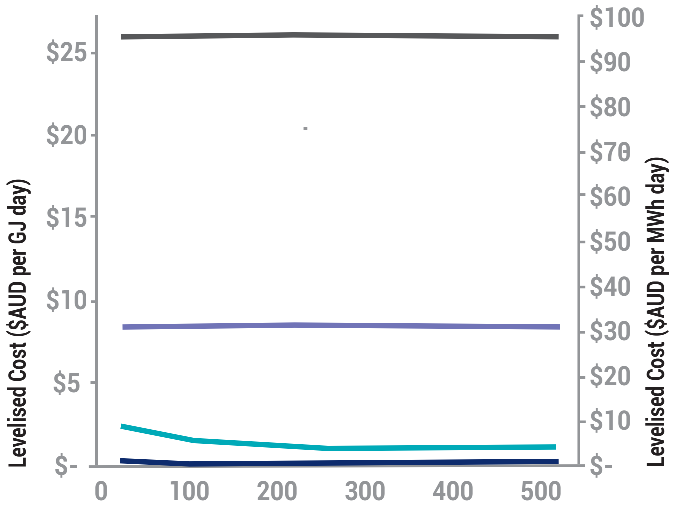
Levelised Cost of Storage - 4hrs

(10TJ/day | 116MW | 70t/day H2)



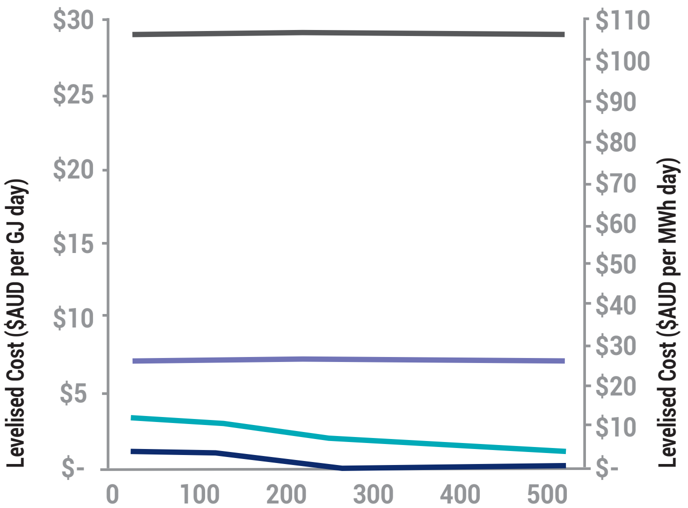
Levelised Cost of Storage - 4hrs

(500TJ/day | 5,800MW | 3,500t/day H2)



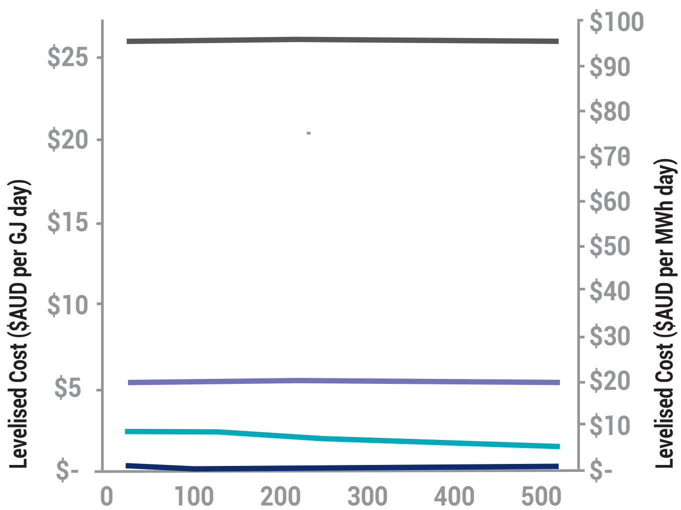
Levelised Cost of Storage - 24hrs

(10TJ/day | 116MW | 70t/day H2)



Levelised Cost of Storage - 4hrs

(500TJ/day | 5,800MW | 3,500t/day H2)



Natural Gas Pipeline — Hydrogen Pipeline — BESS — PHES

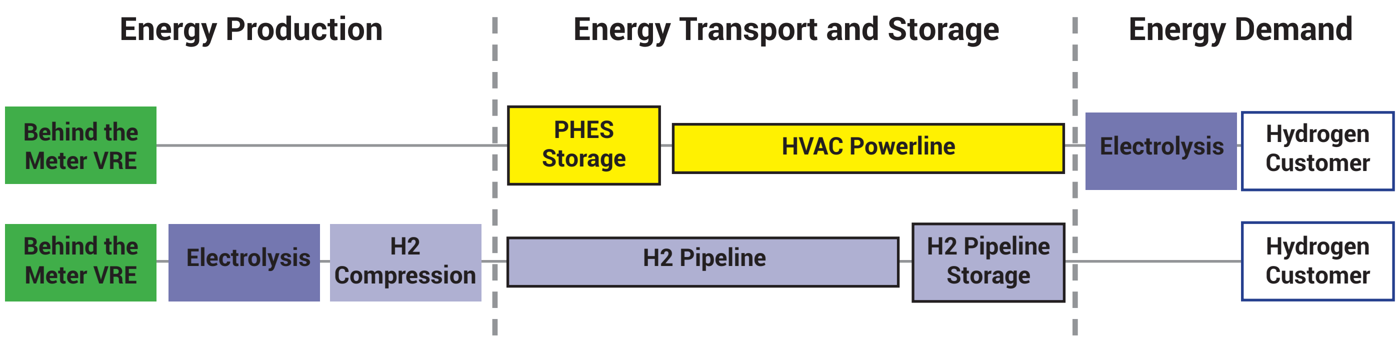
Hydrogen customer benefits greater than lower transport and storage cost alone

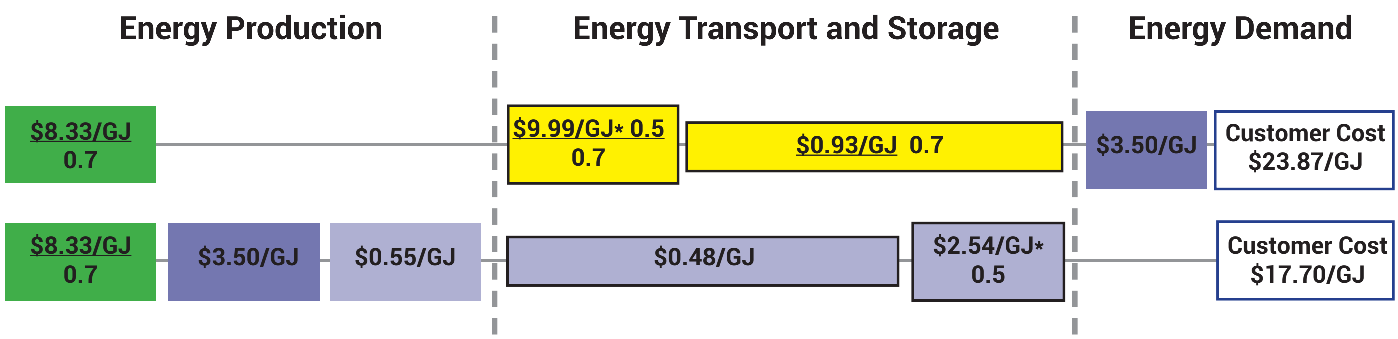
From the perspective of the hydrogen customer, the benefits of receiving hydrogen via pipeline are greater than the reduced transport and storage costs alone. Assuming that energy needs to be transported, transporting and storing energy after electrolysis rather than before electrolysis means that the energy consumed by electrolysis (typically 30 per cent) doesn't need to be transported.

This reduces the throughput capacity of energy transport and storage infrastructure, resulting in a lower cost of hydrogen for customers. This also opens the opportunity for hydrogen customers to access low-cost behind the meter solar PV and wind generation for hydrogen production.

An indicative hydrogen supply chain comparison undertaken by GPA Engineering can be seen below. Through this example, the expense of transporting the energy lost through electrolysis can be seen as significantly contributing to the cost of hydrogen for customers.

While this is a one-for-one comparison, the opportunity of network economics applies to electricity and gas infrastructure alike, meaning that networks of hydrogen pipeline are expected to deliver energy at a lower cost than electricity networks as well. The full value created through hydrogen networks relative to electricity networks or individual hydrogen pipelines requires further analysis.





How you can use this data

When undertaking energy value chain analysis, an understanding of energy production and use technologies alone are insufficient to understand the entire value chain. It is possible for one energy production technology to produce more expensive energy than another, but for energy infrastructure to result in equal or opposite costs for customers.

APGA commissioned the Pipelines vs Powerlines study to be undertaken in such a way which would allow anyone interested in a hydrogen or renewable gas future to consider pipeline infrastructure alongside powerlines infrastructure options.

Prior to this report, little robust Australian data existed comparing the costs of new pipeline and powerline infrastructure, and even less considering the opportunity of hydrogen pipeline infrastructure.

Using the data available in the Pipelines vs Powerlines report, energy transport and storage costs per unit energy can be estimated and inserted in high-level value chain cost estimates such as the one seen on the previous page. Where distances longer than 500km are required, this can be estimated by adding pipeline lengths together and adding an estimate of midline compressor cost also available in the report.

It is hoped that with these high-level cost estimates, developers, policy makers and climate advocates alike can come to informed conclusions about the potential for a renewable gas future delivered via renewable gas infrastructure.

APGA intends to build on this study by considering where such a renewable gas future could take the nation, and by integrating this data with the growing body of renewable gas industry analysis being developed around the globe.

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[1] Australian Energy Update 2021, Australian Federal Government Department of Industry, Science, Energy and Resources 2021
https://www.energy.gov.au/publications/australian-energy-update-2021

[2] Western Victorian Transmission Network Project High-Level HVDC Alternative Scoping Report, Moorabool Shire Council 2021
https://www.moorabool.vic.gov.au/files/content/public/about-council/large-projects-impacting-moorabool/western-victoria-transmission-network-project/wvtnp-high-level-hvdc-alternative-scoping-report.pdf

[3] 2020 ISP Appendix 5. Renewable Energy Zones, Australian Energy Market Operator 2020
https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en

Attachment 2: Pipelines vs Powerlines – A Technoeconomic Analysis in the Australian Context

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Final Report

Pipelines vs Powerlines – A Technoeconomic Analysis in the Australian Context

GPA Project No: 210739
GPA Document No: 210739-REP-001
Report commissioned by the Australian Pipelines and Gas Association

Pipelines vs Powerlines: Reviewing Energy Transmission

256 case map

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4hr, 12hr, 24hr

Hydrogen Pipeline | Natural Gas Pipeline
Vs.
HVAC Powerline | HVDC Powerline

A techno economic comparison of Australian energy transmission infrastructure, covering natural gas pipelines, gaseous hydrogen pipelines, HVAC and HVDC power lines.

Reliability of supply

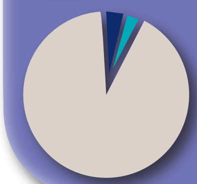
39,000 km of high pressure gas pipelines

0.03 events per 1000km a year loss of supply

43,000 km of high voltage power lines

0.42 events per 1000km a year loss of supply

Energy Storage 2020



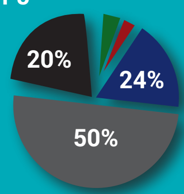
Electricity
0.017 TWh

Gas Pipelines
2.3 TWh

Underground Gas Storage
64.3 TWh

Energy End Use (2019/2020)

Electricity 858 PJ
- renewables 194 PJ
- coal & oil 485 PJ
- gas 179 PJ



Coal 102 PJ

Gas 1,012 PJ

Renewables 170PJ

Refined Products 2,125 PJ

Energy transport through **pipelines** is up to **5 times more cost effective** than **energy transport** via **high voltage powerlines**

4hr energy storage often comes at **no additional cost** when using typical pipeline construction principles

Energy storage in **pipeline linepack** can be **100s** of times more **cost effective** than **utility scale battery** and **pumped hydro energy storage**

All cases modelled in this report show that energy transport and storage via hydrogen or natural gas pipeline is more cost effective than electricity transport and storage in all scenarios.

EXECUTIVE SUMMARY

Gas and electricity energy transmission networks transfer energy around Australia from producers to its consumers at the time and place it is needed. As Australia transitions to a net-zero emissions future, major new transmission infrastructure will be needed. Finding the most cost-effective means of energy transport and storage is a high priority to ensure energy remains as affordable and reliable as possible.

Today, more energy is transported and stored through gas infrastructure than through electricity infrastructure[1,2]. This is in part due to gas infrastructure's ability to deliver energy transportation and storage services flexibly, reliably and at a comparatively lower infrastructure cost. APGA engaged GPA Engineering to assess comparative options for energy transmission by examining:

- costs of energy transport of high-voltage direct current (HVDC), high-voltage alternating current (HVAC) transmission lines, natural gas pipelines and hydrogen pipelines;
- costs-of energy storage of batteries, pumped-hydro, natural gas pipeline packing and hydrogen pipeline packing; and
- Investigating reliability and environmental impacts of electricity, gas transmission and storage infrastructure.

Levelised Cost of Energy Transport

The Study finds that, across a wide range of scenarios, newly constructed pipelines are more cost-effective than newly constructed electricity transmission infrastructure at transporting energy by a wide margin. The physical properties of hydrogen and the current safety factors applied for hydrogen transport by pipeline result in it costing more than natural gas. Despite this, transporting the same amount of energy as hydrogen in a pipeline, compared to electricity via either HVAC or HVDC powerlines, is cheaper.

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[1] In *Energy Storage: we can be happy underground (2018),* Energy Networks Australia calculates gas pipeline storage at around 5 Snowy 2.0s.
https://www.energynetworks.com.au/news/energy-insider/energy-storage-we-can-be-happy-underground/

[2] The *Australian Energy Update 2021* shows 1,012PJ of final gas consumption compared to 858PJ final electricity consumption, with 179PJ of final electricity consumption coming from gas power generation. https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202021%20Energy%20Update%20Report.pdf

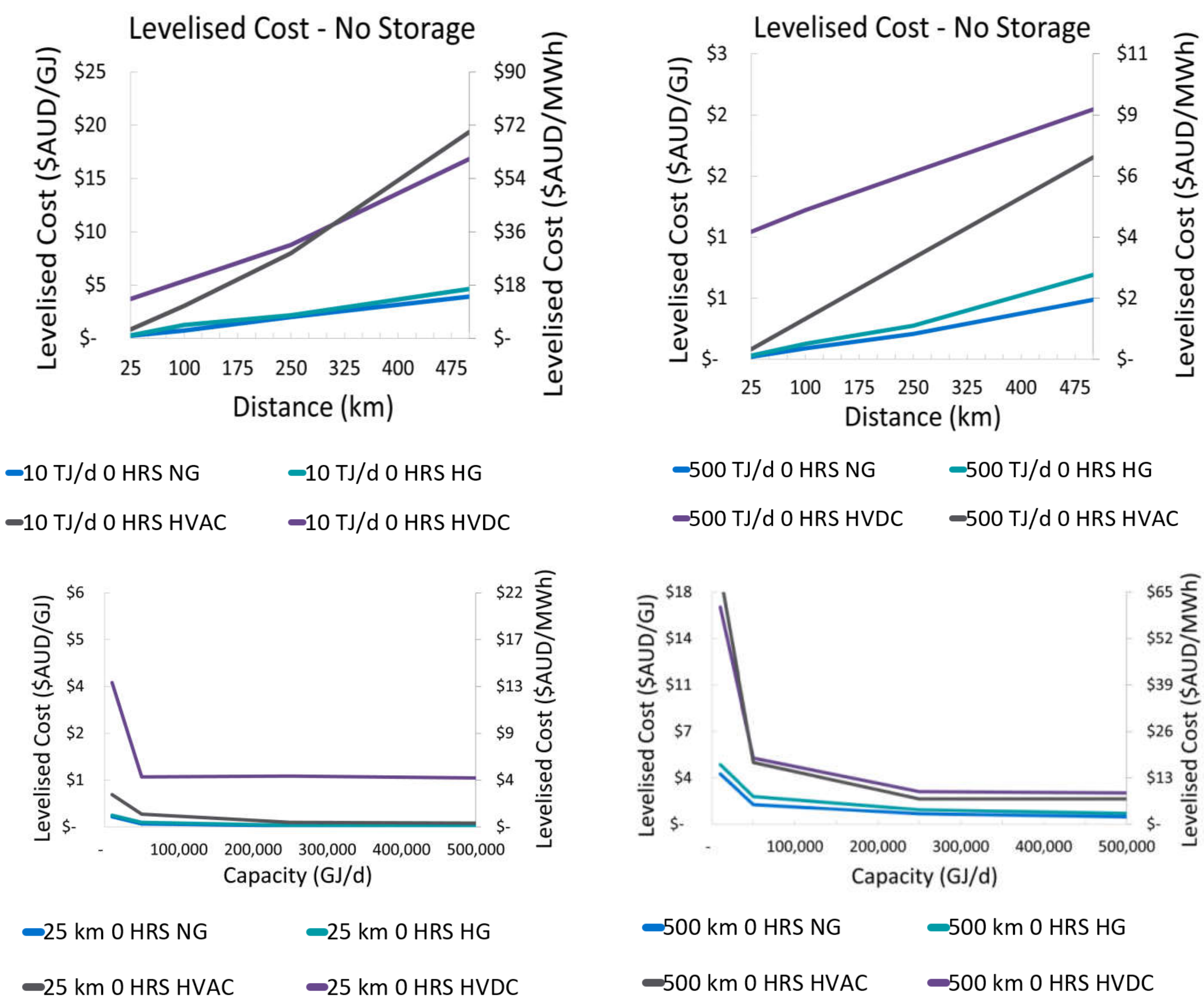

Figure 1: Levelised cost of transport (zeros storage) at throughput and distance extremes

> ***Hydrogen** pipelines are a **more cost effective** means of energy transport than either **HVAC** or **HVDC** powerlines*

The cost advantage of pipeline infrastructure tends to increase with distance with the cost of energy transport through gas pipeline remaining well below the cost of energy transport by powerline even at the energy throughput extremes examined. Notably, there is still a notable advantage at the lower range examined with energy throughput as low as 10TJ/day (116MW) and at distances as short as 25km.

Energy Storage Outcomes

Further advantages associated with pipeline infrastructure can be seen when considering the cost of energy storage. Figure 2 demonstrates the significantly lower costs to store a given volume of energy as gas or hydrogen compared with storing the same volume of energy in utility scale batteries (BESS) for short duration and pumped hydro energy storage (PHES) for storage durations above four hours. As with energy transport, energy storage in hydrogen pipelines is more expensive than energy storage in natural gas or renewable methane pipelines but is significantly less expensive than energy storage via the electricity storage options of BESS or PHES.

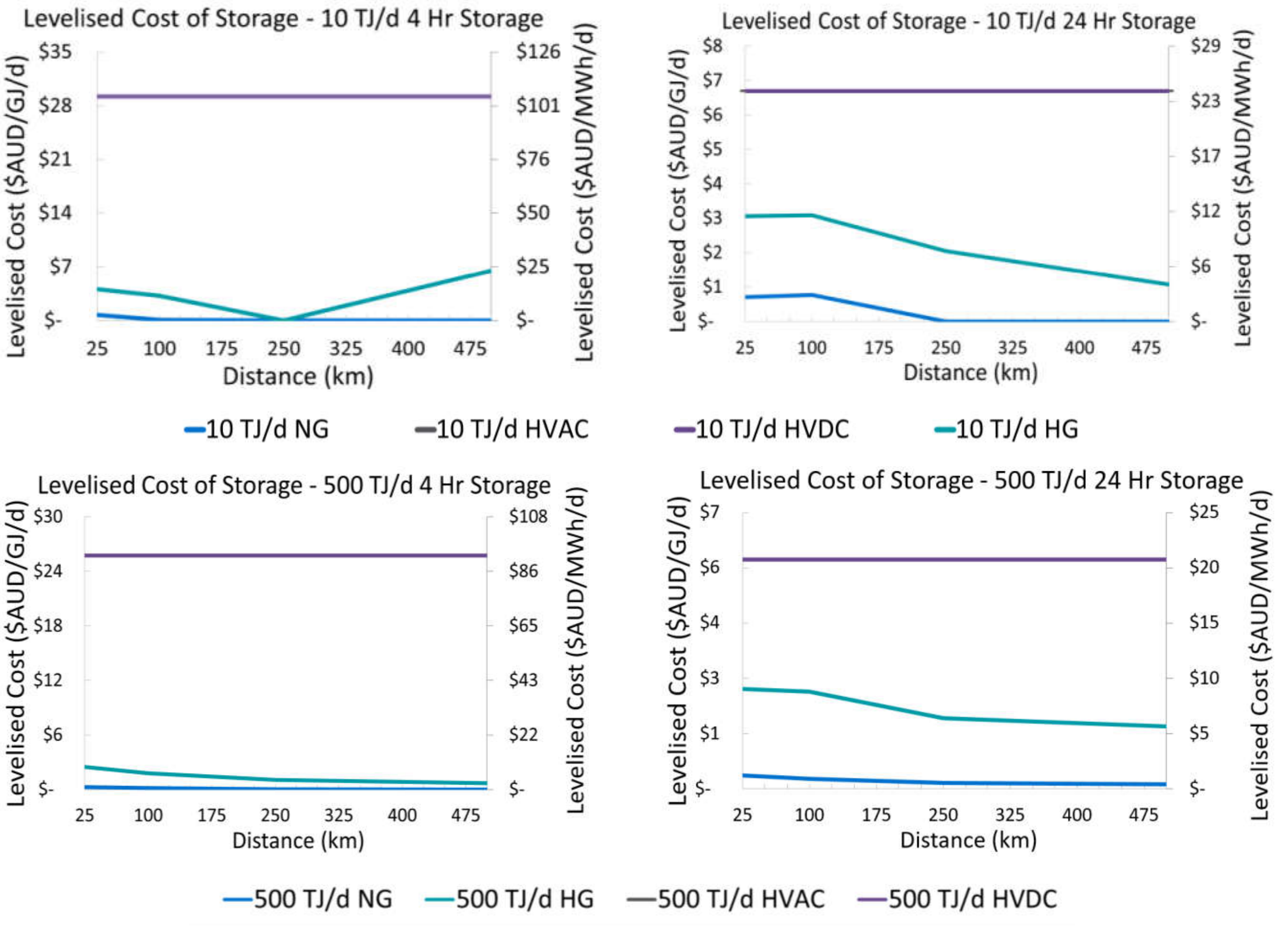

Figure 2: Levelised cost of storage (varying storage) for 10 and 500 TJ/d

> Gas pipelines have had a **significantly** lower number of loss of supply incidents per 1000km per year when compared to high voltage transmission lines

Reliability, Environmental and Safety

The Study also identified additional reliability, environmental and safety advantages of pipeline infrastructure. The reliability of energy infrastructure can be considered in terms of loss of supply incidents per 1000km per annum. Over the past decade, gas pipelines demonstrate markedly superior reliability when compared to high voltage transmission lines in terms of average loss of supply events per annum per kilometre of installed infrastructure.

Table 3: Loss of supply comparison

Infrastructure	Period of Review	Approximate length	Loss of Supply Events	Event per annum (average)	Events per annum per km installed
Gas pipelines	9 years (2009-2018)[3]	39,000	**10 (9 leaks, 1 rupture)**	1.1	0.03
HV Powerlines	9 years (2010-2019)[3]	43,000	**164**	18.2	0.42

Gas pipelines have had a **significantly** lower number of loss of supply incidents per 1000km per year when compared to high voltage transmission lines

Methodology

The Study undertook a technoeconomic analysis of energy transport options, deriving levelised cost of energy transport and levelised cost of energy storage from Association for the Advancement of Cost Engineering (AACE) Class 5 engineering estimates of capital expenditure (CAPEX) and operating expenditure (OPEX). To determine the relative merits of energy transport via pipelines and powerlines, GPA compared:

- Energy transport via natural gas pipeline (NG), hydrogen gas pipeline (HG), HVAC powerlines and HVDC powerlines;
- Energy transport across distances spanning 25km to 500km
- Energy transport capacities from 10TJ/day (116MW) to 500TJ/day (5.8GW)
- Energy storage options including no storage, 4hrs, 12hrs and 24hrs energy storage

Outputs of the Study could be used to compare a range of energy production and utilisation scenarios, rather than fixing the data to a specific configuration or use case

[3] Note that the period of review is offset by one year due to differences in availability of incident data available publicly. Both assessments cover an equivalent nine-year duration.

The Study excludes the relative advantages and disadvantages of specific energy production and utilisation technologies in the analysis of energy transport and storage. This was done so that the outputs of the Study could be used to focus on the transmission infrastructure while considering a range of energy production and utilisation scenarios, rather than fixing the data to a specific configuration or use case. As such, boundaries of the Study were drawn at the entry and departure of the transport infrastructure. Cost of electricity, natural gas or hydrogen production, inlet compression (for gaseous pipelines) or downstream metering and regulations, as well as end use utilisation including any energy conversions, or the relative efficiencies of these, were excluded from the scope of the Study.

Finally, analysis considered only standard infrastructure configurations and design standards used in Australia today, as well as considerations for international standards in the absence of Australian standards such as adopting American Society of Mechanical Engineers (ASME) B31.12 Option A requirements for hydrogen pipeline design. This ensured that the analysis was not based on any hypothetical design that is reliant on future research or theory development, or experimental testing. Using standard pipe and powerline sizes led to levelised cost charts not tracing mathematically perfect curves due to the relative proximity of chosen cases to step changes in design.

Use of Study Outputs

Energy transmission and storage infrastructure is a key element in determining the most cost-effective way to deliver energy to a customer. Consider the comparison in Figure 3 of two possible energy value chains for the delivery of hydrogen to a customer.

In both cases, the cost of the variable renewable energy (VRE) and electrolyser facility is the same, however the value chain costs are substantially different. These differences will impact on the delivered cost of hydrogen for the customer. Black borders in Figure 3 identify components provided by this report. It should be noted that in this example conversion of electricity to hydrogen (via electrolysis) is required, whereas if the end use is electricity, conversion costs would only apply to the pipeline scenario.

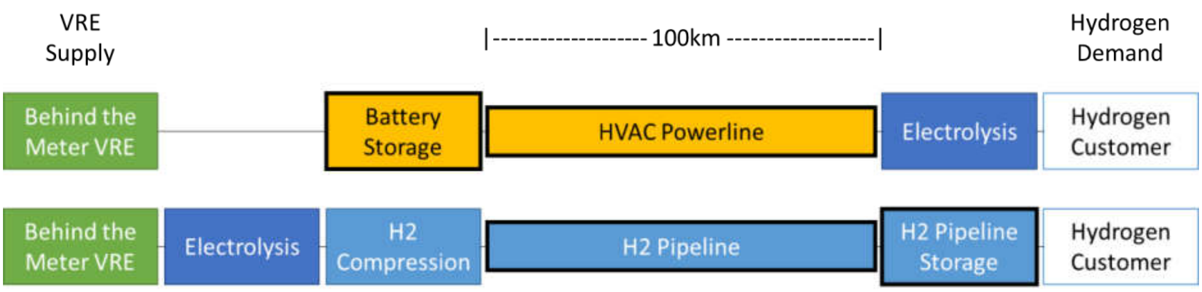

Figure 3: Indicative energy value chain comparison

Including high level cost estimates of various technologies (included in Appendix 2), the worked example seen in Figure 4 can be derived. As seen in this above example, locating electrolysis immediately downstream of VRE generation results in:

- lower cost hydrogen pipeline transport
- lower cost hydrogen energy storage
- less energy transport and storage being required overall as electrolysis energy losses occur upstream of transport and storage.

This worked example demonstrates the various ways in which locating electrolysis close to VRE and taking advantage of energy storage in hydrogen pipelines can deliver a lower cost hydrogen product to customers.

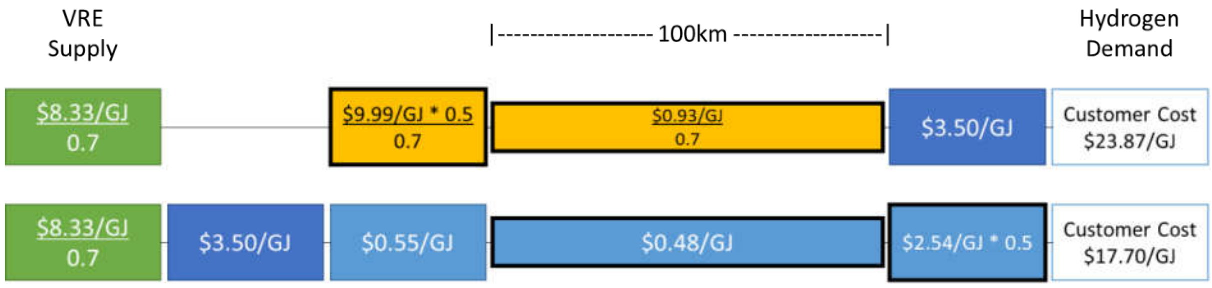

Figure 4: Hypothetical high level value chain cost comparison

Report Conclusion

Given their advantages in delivering lowest cost transmission and storage, the Study's findings suggest that pipelines will often remain the lowest cost form of energy transport for large throughput, moderate distance scenarios typical of gas pipeline infrastructure today. The cost advantage of energy pipelines improves with increased throughput and distance and requires much lower upfront cost to integrate significant volumes of energy storage in comparison to powerline infrastructure. These results indicate that hydrogen pipelines are likely to play a central role in Australia's net zero energy market as energy transport and storage via hydrogen pipeline is cost competitive when compared to high voltage powerlines and BESS or PHES for energy storage.

The benefit of low-cost energy transport and storage through hydrogen pipelines will be most advantageous where the hydrogen being transported can be used directly by customers, whether they be Australian households, large-scale industrial customers or export. In every instance, the full energy supply chain and the relative efficiencies of each component must be considered, in particular where hydrogen is being considered for reconversion back into electricity after transmission.

The authors of this report hope that the analysis provided is used by industry and policy makers to make informed choices about energy infrastructure. While the analysis undertaken here is high level, based on CAPEX estimation to AACE Class 5, it is a good starting point from which to consider the most cost-effective form of energy transport ahead of undertaking more detailed engineering analysis and further refined cost estimation.

Powerlines will continue to have a place in servicing the growing electricity demand sector. However, the results from the Study show energy transport and storage via pipeline infrastructure is a more cost competitive and reliable option than its electricity counterparts and should be considered an essential part of the future netzero energy value chain.

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LIST OF ACRONYMS

Acronym	Definition
AS	Australian Standard
ASME	The American Society of Mechanical Engineers
API	American Petroleum Institute
BESS	Battery Energy Storage System
BG	Bank Guarantee
CAPEX	Capital Expenditure
CoP	Code of Practice
CP	Cathodic Protection
CS	Carbon Steel
DN	Nominal Diameter
EPCM	Engineering, Procurement and Construction Management
ERW	Electric Resistance Welded
EVR	Erosional Velocity Ratio
FBE	Fusion Bonded Epoxy
FJC	Field Joint Coating
GJ	Gigajoule
HDD	Horizontal Directional Drilling

HP	High Pressure
HRC	Hot Rolled Coil
HSAW	Helical Submerged Arc-Welding
HSE	Health, Safety and Environment
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
H2	Hydrogen Gas
ILI	In Line Inspection
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydride Carrier
LP	Low Pressure
LSAW	Longitudinal Submerged Arc-Welding
MAOP	Maximum Allowable Operating Pressure
MPa	Mega Pascal
MW	Mega Watt
NEM	National Electricity Market
NG	Natural Gas
OPEX	Operational Expenditure
PHES	Pumped Hydro Energy Storage
SCADA	Supervisory control and data acquisition
SMYS	Specified Minimum Yield Stress
SOW	Scope of Work
SS	Stainless Steel
TIC	Total Installed Cost
TJ	Terajoule
VRE	Variable Renewable Energy

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1 INTRODUCTION

Stakeholders across the Australian energy landscape are considering the roles that renewable sources of hydrogen, methane and electricity will play in Australia's future energy mix. One of the key considerations when decarbonising the energy industry is determining the most cost-effective methods for transporting energy across Australia. High voltage powerlines are commonly used to transport electricity generated from large scale renewables as well as conventional carbon-based fuels to consumers.

Natural gas pipelines have been the most cost-effective means of transporting large volumes of energy over long distances from remote oil and gas reservoirs to industrial, commercial and residential consumers concentrated at major population centres, remote mine sites and LNG export hubs. Australia is also investigating the role that renewable methane, biogas and green hydrogen may play in a zero-carbon future, to support decarbonisation of energy networks, transport and heavy industries, and other hard-to-abate sectors. Renewable hydrogen is also being targeted as a large-scale export commodity to supply traditional energy importing economies.

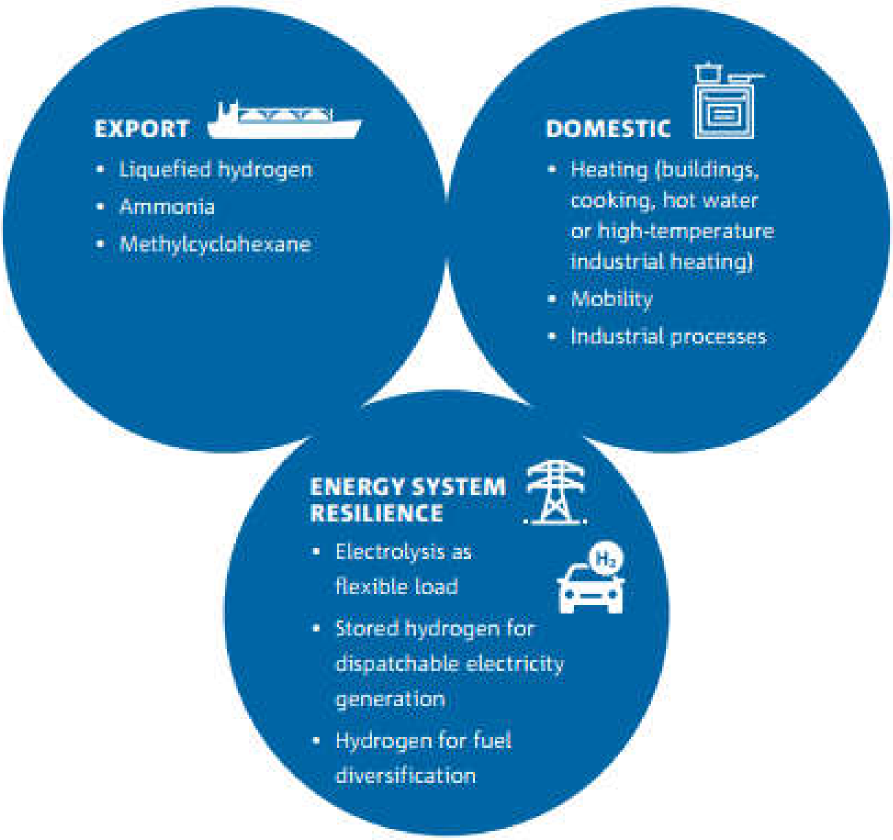

Figure 5: Australia key opportunities large-scale hydrogen production capacity (ref. Hydrogen COAG White Paper)

For hydrogen produced from renewable power generation, different types of energy transmission infrastructure may suit depending on the distance between power generation and hydrogen end use, storage requirements and scale. Similarly, increased investment in remote renewable generation may require transportation of energy over a distance and at a scale not commonly undertaken using electrical infrastructure alone. Consideration is required in both scenarios of whether pipelines or powerlines provide the more effective solution for energy transport and which one provides the lowest cost options for energy storage.

The cost of energy transport is a critical factor when making energy infrastructure investment decisions. Equally important is ensuring transmission infrastructure is reliable, safe and has a minimal impact on the environment. The key outcome of the Study is to provide information that aids in understanding these factors for variation transmission scenarios.

There are three primary energy forms that will be covered in the Study:

Methane is the simplest hydrocarbon form (CH_4) and is the principal component in natural gas. Much of the heating in Australia and a significant portion of power generation is fuelled by natural gas. Natural gas is currently transported via a pipeline transmission network of more than 39,000km around the country. In the future, other forms of renewable gas including biogas and renewable methane, produced from carbon capture and methanation, may be produced in sufficient quantities to be transported similarly.

Electricity is predominantly generated using coal and gas in Australia, however will increasingly be generated from renewable sources like large scale wind and solar farms. Where energy storage is required, electricity transported via HVAC and HVDC transmission lines is supplemented with BESS, PHES or similar energy storage facilitate.

Hydrogen, a molecule of two hydrogen atoms, is produced as 'green' hydrogen either via electrolysis (commonly alkaline or PEM technology) or as 'blue' or 'brown' from carbon based fuels such as natrual gas via steam methane reformation, with or without carbon capture and sequestration respectively. Hydrogen can be transported and stored in carbon steel pipelines similar to natural gas, but limitations in current research require higher safety factors, and limited strength grades compared to natural gas transmission pipelines to manage risks associated with embrittlement. Additionally, hydrogen has lower volumetric energy density and takes greater energy to compress, reducing the transport and storage efficiency compared to natural gas. Hydrogen density may be improved for export by conversion to liquid hydrogen or other hydrogen product carrier forms such as ammonia or MCH (methyl-cyclo-hexane).

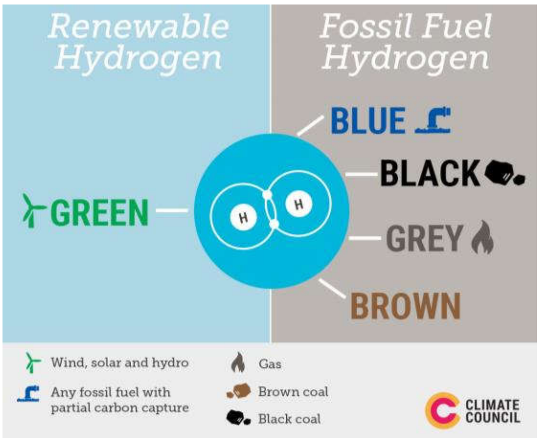

Figure 6: Typical hydrogen colour scheme associated with generation source (Climate Council)

Renewable hydrogen production cost is expected to continue to decline over the coming decades, as shown in

Figure 7. Combined with a greater focus on domestic energy decarbonisation, and the potential hydrogen export market, renewable hydrogen developments are expected to grow over the next two decades. Understanding the transmission pathways and new energy infrastructure required for energy in various forms such as electricity or as a gaseous fuel is a key input when making appropriate infrastructure investment decisions.

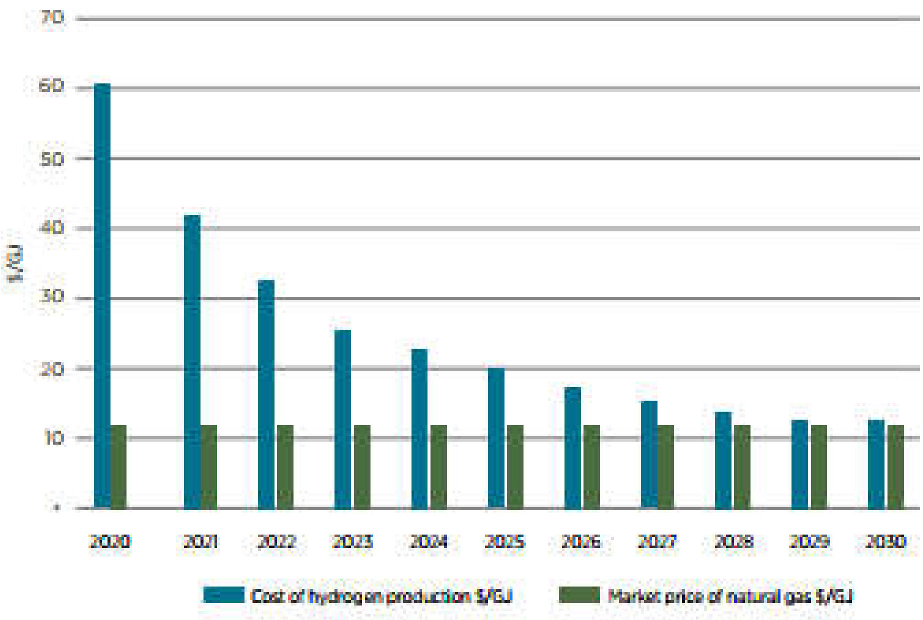

Figure 7: Projected hydrogen costs (Australian Net Zero Plan 2020)

1.1 STUDY PURPOSE AND OBJECTIVE

The focus of the Study is to explore different energy transmission options, and compare the costs for a selection of transmission technologies including natural gas, hydrogen gas, high voltage electrical transmission (HVAC and HVDC) and associated storage options including; pipeline packing and electrical energy storage via BESS and PHES.

This report includes insights on the technical feasibility, limitations, cost, equipment, pipeline / wire sizing and configurations for a range of energy throughput (10-500 TJ/day), distance (25-500km) and storage duration (0-24 hrs) scenarios including associated analysis and assumptions.

The intent is to compare transmission infrastructure within the range of scenarios, to understand the commercial and technical viability of various energy transmission solutions and to identify comparable costs across the different throughput and storage capacities. The report also assesses reliability and considers safety and environmental factors across the different infrastructure.

It is recognised that making clear comparisons between electric power line and pipeline transmission infrastructure (as well as the differences between natural gas and hydrogen) is not a simple task. Generic cases were set out in a case matrix (defined in Appendix 1) so the transmission and storage scenarios could be compared across each technology. Case matrix establishment is discussed further in section 3.2.1.

2 ENERGY TRANSMISSION AND STORAGE IN AUSTRALIA

2.1 PIPELINES

The Australian pipeline network is largely made of natural gas lines connecting onshore and offshore Australian gas fields to energy demand clusters such as major cities and regional centres, remote mining operations and large-scale LNG export facilities. The size of the Australian continent and remote location of major oil and gas reservoirs mean that transmission pipelines typically cover great distances. Due to these long distances and the larger concentration of gas consumers remote from the gas source, Australian pipelines typically operate at high pressure, are designed with smaller diameters using high strength steel and operate at a high stress (72-80 per centof SMYS) and with the intent of reducing pipeline material costs to optimise shipping capacity.

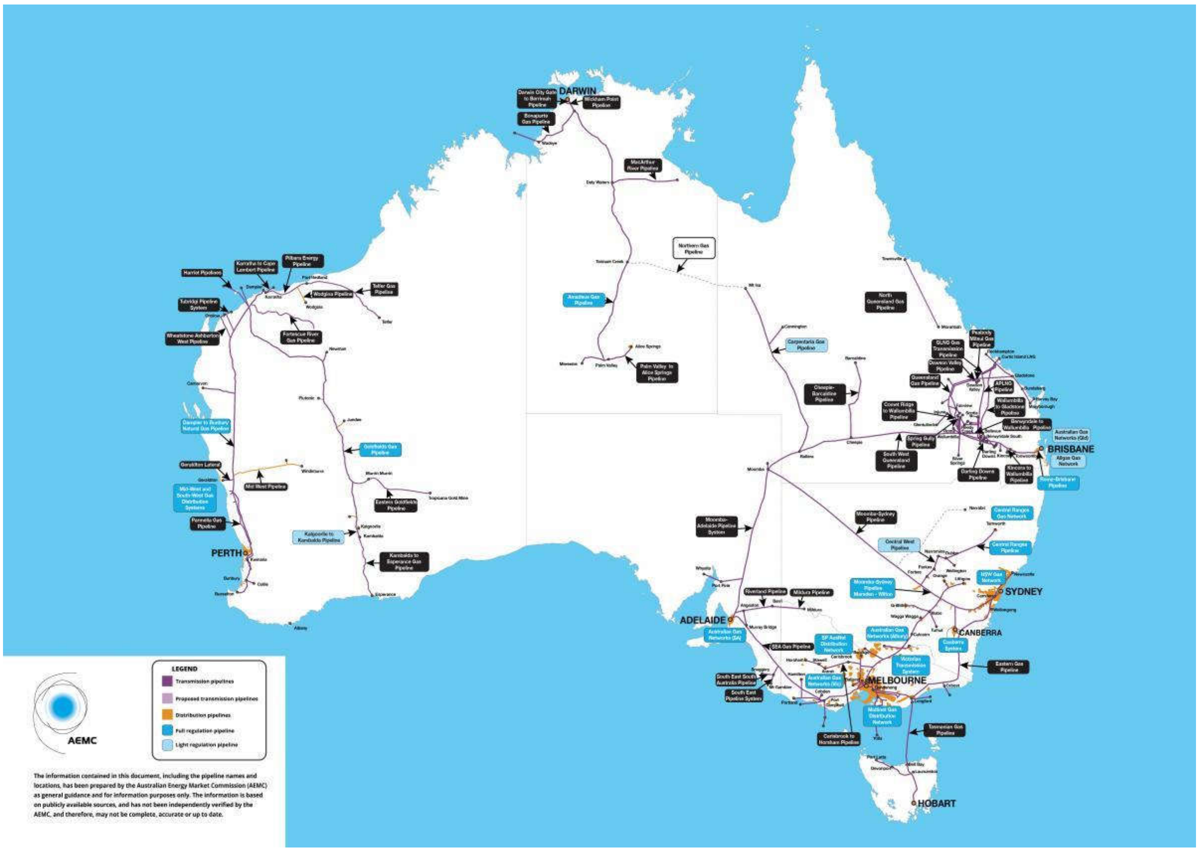

Figure 8: Australia gas pipelines (Australian Energy Market Commission)

Table 1 below provides examples of existing major gas transmission and gas storage pipelines in Australia.

Table 1: Examples of Australian pipeline assets

Pipeline	Asset Owner	State	Length	Pipeline Details	Approximate Capacity details
SEA Gas pipeline	SEA Gas	SA / Vic	690 km	18" / DN450	315 TJ/day
Jemena EGP pipeline	Jemena	Vic	800 km	18" / DN450	250-350 TJ/day
Jemena Northern gas pipeline	Jemena	NT	620 km	12" / DN300	92 TJ/day
DBGNP	AGIG	WA	1530 km	26" / DN650	845 TJ/day
Parmelia Pipeline	APA	WA	415 km	14" (DN350)	70 TJ/day
LNG export pipeline – either APLNG, QCLNG or GLNG	Origin, QCG, Santos,	QLD	APNLG: 350km (excl narrows crossing) GLNG: 420km	APLNG: 42" (DN1050) GLNG: 42" (DN1050)	APLNG: 1560 TJ/day GLNG: 1430 TJ/day
Coloundra Gas Storage Pipeline	Jemena	NSW	3.5 km	42" (DN1050)	
Mortlake Gas PIpeline	SEA Gas (formerly Origin)	Vic	83 km	20" DN500	400 TJ/day

Pipelines offer unique operating capabilities when compared to other transmission technologies. They have the ability to accommodate very large energy throughput capacities, store large inventory within the asset and maintain to high reliability of service. These factors make high-pressure pipeline transmission ideally suited for reliable long-distance energy transmission. Pipelines also experience very little energy loss through transport. Pipeline flow results from differential pressure along a pipeline when highly compressed gas is introduced at the inlet and removed from the demand end, or other offtakes along the pipeline. The friction between the gas and the pipe wall, and through flow restrictions (such as facility equipment and smaller diameter piping) is the only cause of energy loss across pipeline transport. Effectively the cost of power generation to drive inlet or intermediate gas compression (either gas fired or direct electric drive), to accommodate the friction loss is where this cost is incurred. Compared to powerlines, this energy loss over distance is considerable smaller.

High pressure pipelines do tend to 'lose' some gas in the form of unaccounted for gas, but this is mostly due to measurement error (the imperfection of measuring gas in and out of a pipeline) and limited to below two per cent of throughput.

Both existing natural gas assets, as well as new pipeline developments, have the potential to provide the energy transport and storage infrastructure that enables a lower cost decarbonisation model of Australia's energy industry. These pipeline assets may be used to reliably transport biogas and renewable methane as well as gaseous hydrogen at the lower infrastructure costs in the future and remain a critical part of the energy supply infrastructure, linking production to end use and providing cost effective energy storage.

2.2 HIGH VOLTAGE TRANSMISSION LINES

Electrical infrastructure in Australia is grouped into a number of interconnected systems, the largest being the National Electricity Market (NEM) which encompasses Queensland, NSW, Victoria, SA, the ACT and Tasmania. Other systems in Australia include the South West Interconnected System (SWIS) in Western Australia and the Darwin-Katherine Interconnected System (DKIS) in the Northern Territory. Electricity networks in Australia are unique in comparison to similar developed nations due to significant line lengths, a low density of users and a long thin structure without significant interconnection.

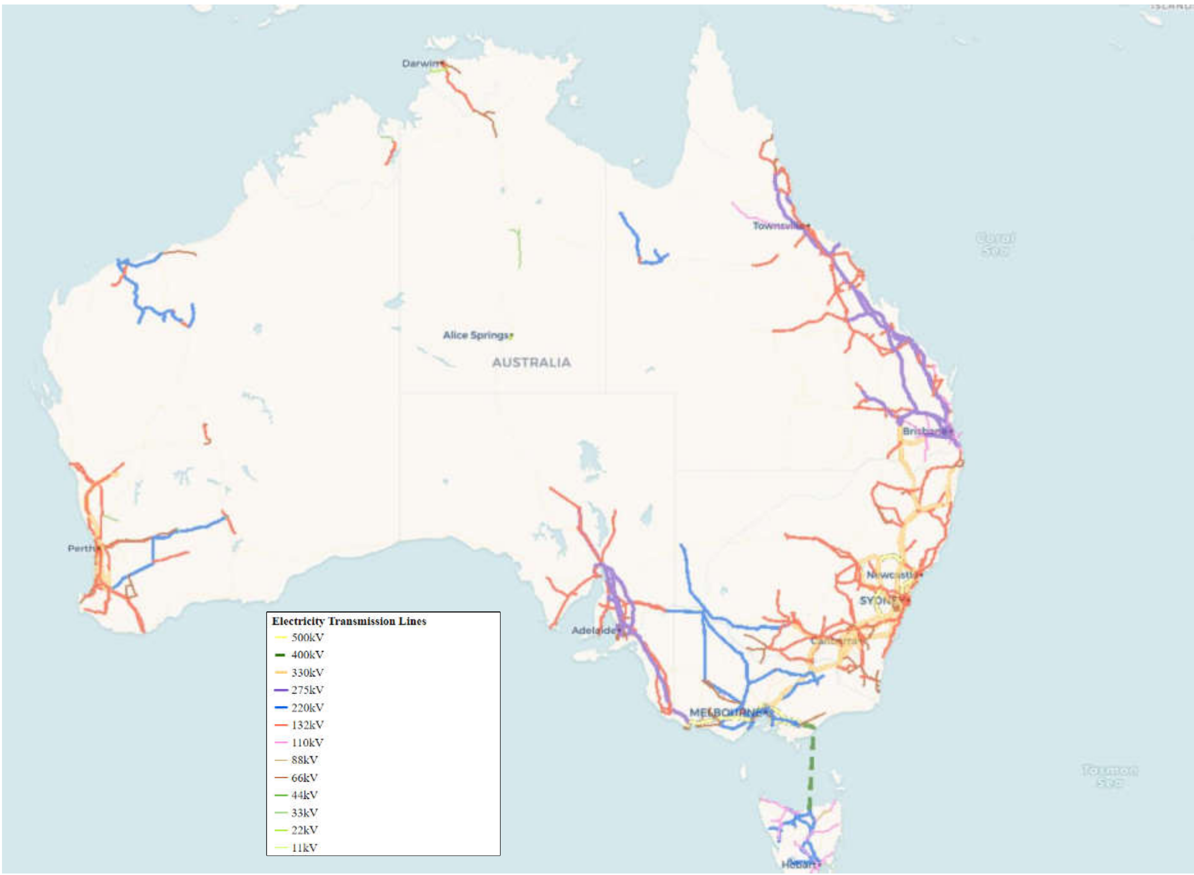

Figure 9: Electrical Networks in Australia (NationalMap[4])

Electrical networks are further split into transmission infrastructure and distribution infrastructure. High capacity 'poles and wires' make up transmission infrastructure and transport electricity in bulk, at higher voltage and efficiently over long distances. For example electrical transmission lines might connect a large generator to a distant load or provide interconnection between States/Territories and regions. Some industrial customers can also be directly connected to the transmission network to meet their large requirements for electrical power.

[4] Available at https://nationalmap.gov.au/

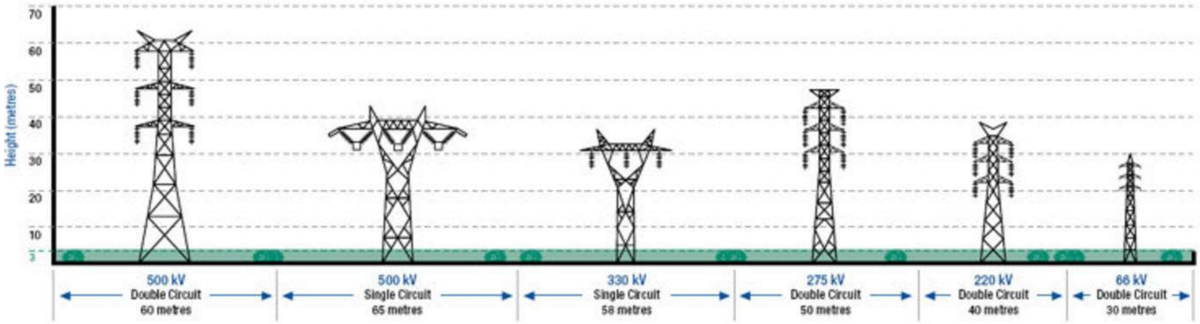

Figure 10: Typical transmission towers in Australia (EnergySafe Victoria)

Distribution infrastructure transports electricity locally and at lower voltages from the transmission connection point to end users like homes, businesses and small industrial users. This Study focused on high throughput and/or long distance transport of energy, so only electrical transmission lines have been considered for comparison with pipelines.

Two technologies exist for high voltage electricity transmission; High Voltage Alternating Current (HVAC) is the most commonly deployed technology with High Voltage Direct Current (HVDC) being advantageous in situations requiring long distance point-to-point energy transmission. Further details regarding application and benefits of each technology can be found in Appendix 4.

Examples of some current operating HVAC and HVDC transmission lines in Australia along with line length and capacity are outlined in the table below.

Table 2: Examples of Australian transmission line assets

Transmission Line	Technical Details	State	Length	Voltage	Nominal Capacity
Murraylink	HVDC Underground cable	SA to VIC	180 km	±150 kV	220MW
Basslink	HVDC undersea cable and overhead transmission line	Vic to TAZ	370 km	400 kV	500MW
Heywood interconnector	HVAC overhead transmission line	SA to VIC	~90km	275kV	650MW
Queensland – New South Wales Interconnector (QNI)	HVAC overhead transmission line	QLD to NSW	~420km	330kV	1,200MW (QLD to NSW)

A transmission line will lose a certain percentage of its transmitted energy as heat dissipated in the overhead line conductors. Due to a phenomenon known as the Skin Effect and differences in corona discharge, HVAC transmission lines will typically have greater losses than a comparable HVDC line. Across both transmission and distribution infrastructure in the NEM the electrical losses are on average 10 per cent of the total energy transported[5].

[5] Loss factors and regional boundaries, Australian Energy Market Operator 2021 https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries

HVAC and HVDC transmission lines have been considered over all distances within the case matrix for comparison with pipeline alternatives. In practice HVDC lines are only cost-effective over long distances and it is highly unlikely they would be constructed over the shorter distance cases.

2.2.1 HIGH VOLTAGE TRANSMISSION LINE PROJECTS AND COSTS IN AUSTRALIA

The NEM is undergoing significant changes to facilitate the transition to higher VRE generation. New transmission assets are proposed to assist with this transition including several projects which are at an advanced stage of development.

Project EnergyConnect is a committed project involving the installation of a new 900km, 800MW interconnector between Robertstown SA and Wagga Wagga in NSW. The project includes installation of new dual circuit HVAC 275kV and dual circuit HVAC 330kV transmission lines. The project also includes augmentation of existing substations and construction of additional substation assets. The total project cost is estimated at $2.28 billion dollars with project completion expected by 2024-25.

The HumeLink project will construct a new 360km HVAC double circuit 500kV transmission line between Wagga Wagga, Bannaby and Maragle. The project includes upgrades to existing substations at Bannaby and Maragle as well as construction of a new substation at Wagga Wagga. The total project cost is estimated at $3.3 billion dollars with project completion expected by 2026-27.

2.3 SAFETY AND RELIABILITY EXPECTATIONS

Energy consumers, whether industrial, commercial or residential, expect a reliable energy supply that doesn’t disrupt their day-to-day business operation or daily lives. Loss of supply can have a significant impact on the consumer and reduce confidence in the reliability of the overall energy system. In some instances, major outages of high voltage power transmission and gas transmission pipelines will impact a large number of customers.

Overall energy reliability to the consumer is a combination of the effective operation of generators, transmission networks and distribution networks. However, taken in isolation, energy transmission networks and their performance is critical. Outages can disrupt the supply between production and downstream consumers. Although some resilience to short term interruption exists in both electricity and gas infrastructure, due to the interconnected nature of both networks (particularly in the east coast of Australia) failures in transmission infrastructure do have potential for loss of supply events that impacts many customers.

Although energy infrastructure is designed to perform against a range of foreseeable design and operating conditions, failures and loss of supply events do still occur in transmission infrastructure. It isn’t feasible to prevent all potential loss of supply scenarios. However, it is important to understand both the comparative historical reliability as well as the potential risk profile for future potential loss of supply events when making infrastructure selection decisions and considering impacts to the end consumers.

2.3.1 GAS PIPELINE SAFETY AND RELIABILITY IN AUSTRALIA

Gas transmission pipelines in Australia have generally operated safely with minimal incidents that have resulted in a loss of containment event, resulting in reduction or curtailment of supply to customers. Australia’s pipeline operators have been capturing incident data since the 1970s, with an incident database widely used to capture near misses and incidents that occur on buried gas pipelines.

Incidents can range from rare events such as lightning strikes, or construction defects, to more common events such corrosion defects, erosion or third-party external interference events (e.g. strikes from an excavator or horizontal directional drill). External interference and corrosion account for 79 per cent of all incidents on operating pipelines from 2001 to 2018, as shown in Figure 11.

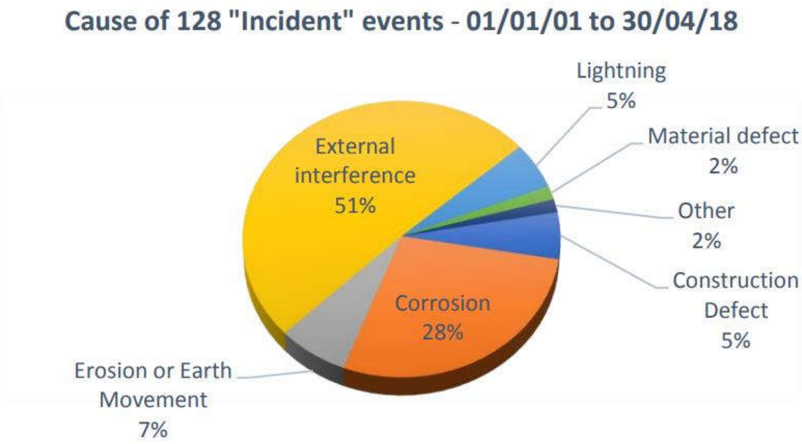

Figure 11: Australian gas pipeline incident type (2001-2018)[6]

In general, incident events with damage are very infrequent, with many near miss events for every third-party impact on a pipeline. Collecting near miss events has provided the industry with more data to work with and identify patterns in the threats to pipelines and how to mitigate them.

The overall rate of incidents per kilometre of installed pipeline has been in decline from the 1960s to the 1990s and has hovered between 0.04 and 0.29 per 1000 kilometre per year over the past 30 years, as shown in Figure 12 below. Sixty-five incidents have occurred in the past 18 years, with an average incident event rate of 0.09 incidents per kilometre-year across the 39,000km kilometres recorded.

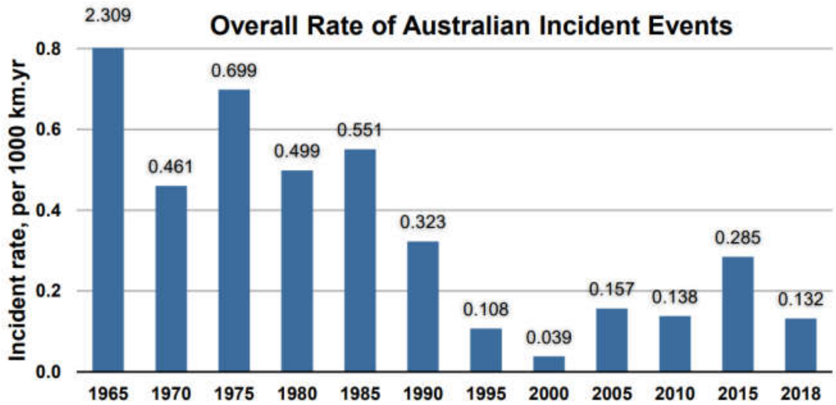

Figure 12: Australian gas pipeline incident rate (1965-2018)[6]

[6] Available at https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/colin_symonds_pipeline_integrity_specialist_0.pdf

As shown in Figure 13, of these incidents, 12 per cent from 2001 to 2018 resulted in a leak (smaller defect with gas release), with only 2 per cent from 2001 to 2018 causing a rupture (larger defect, with a major release). When these rare loss of containment events occur, the cause of failure is relatively evenly spread across different causes (refer Figure 14). The loss of containment events from 2001 to 2018 totalled 17, or 0.03 per 1000 kilometre per year.

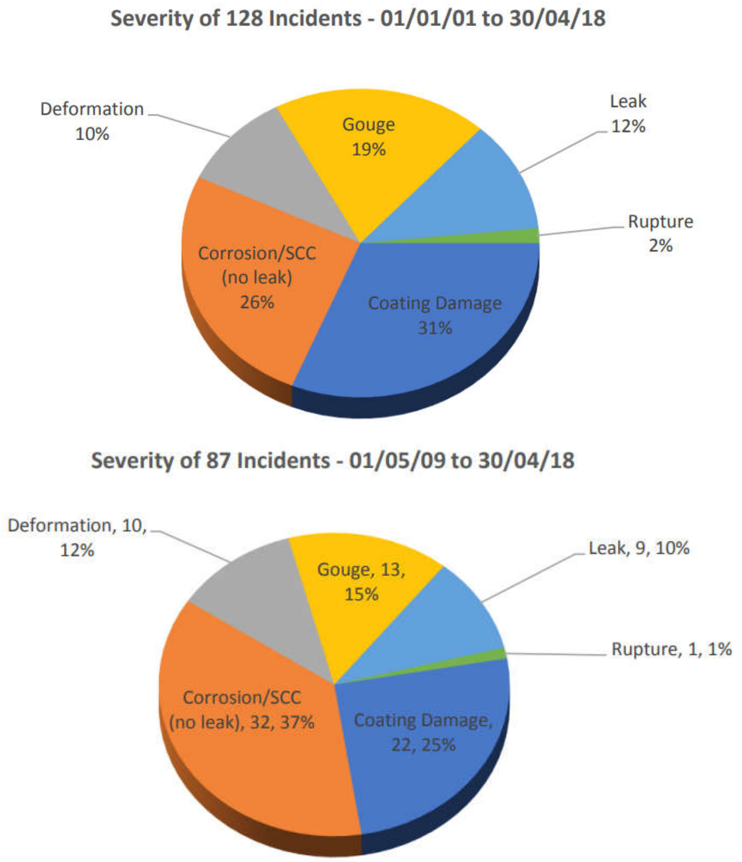

Figure 13: Transmission lines incident event severity[7]

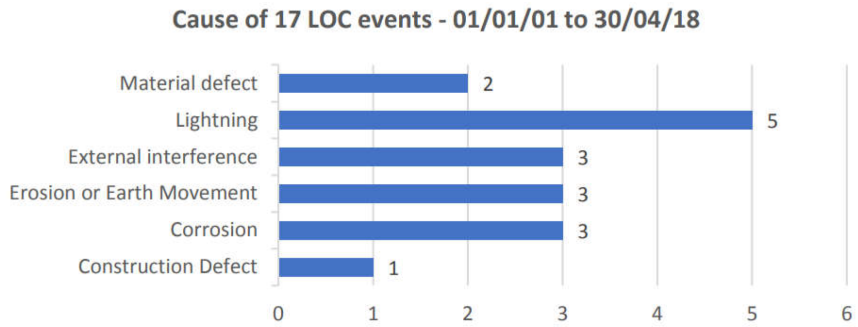

Figure 14: Loss of Containment Events[7]

[7] Available at https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/colin_symonds_pipeline_integrity_specialist_0.pdf

2.3.2 HIGH VOLTAGE TRANSMISSION LINE SECURITY IN AUSTRALIA

High voltage transmission lines are designed to be highly secure with unplanned breakdowns and outages occurring infrequently. The figure below, published by the Australian Energy Regulator (AER) provides an overview of loss of supply events in the NEM since 2006.

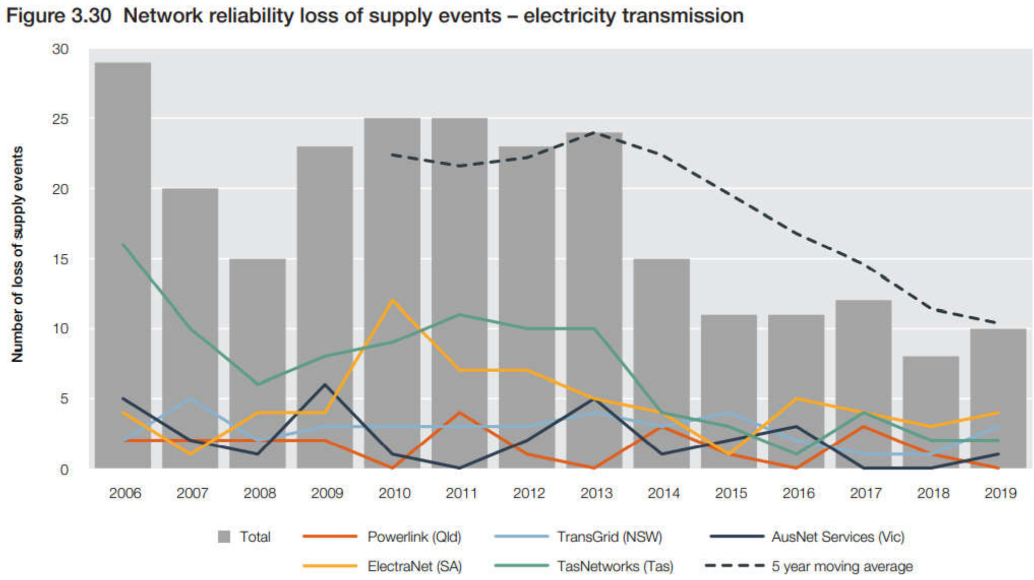

Figure 15: Reliability of transmission infrastructure (AER[8])

The average outage duration is also of interest and this data was also published by the AER in 2018 as a part of its Electricity Transmission Networks Performance Data[9].

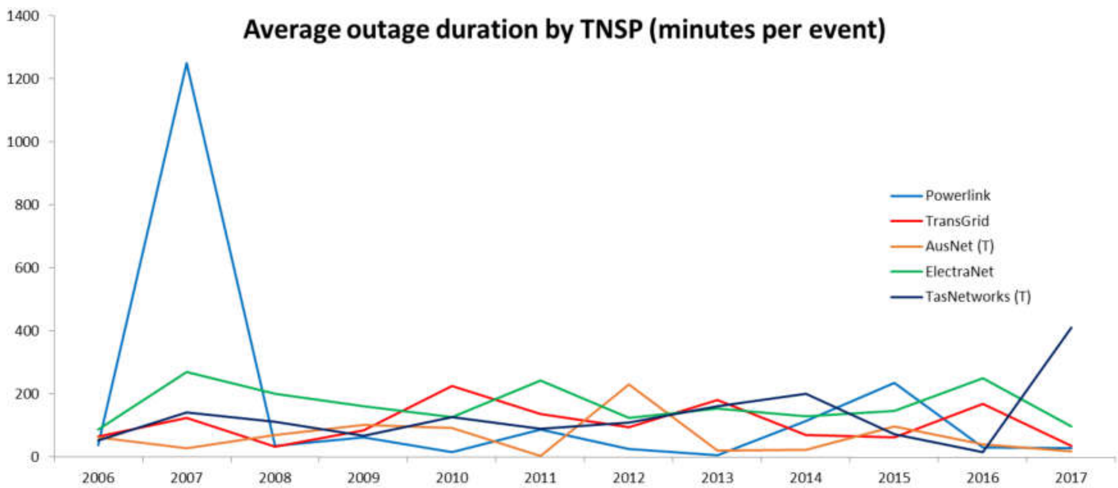

Figure 16: Reliability of transmission infrastructure (AER[3])

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[8] AER, 2021, *State of the energy market 2021,* available at AER: State of the energy market 2021 | energy.gov.au

[9] AER, 2018, *Electricity Transmission Networks Performance Data,* https://www.aer.gov.au/networks-pipelines/performance-reporting/transmission-performance-data-2006-2017

By their nature, overhead transmission lines are exposed to the environment and do suffer failures, particularly due to extreme weather events. Transmission lines and towers are vulnerable to storm activity and extreme winds with some recent examples including:

1. The failure of key 275kV transmission towers in South Australia's Mid North region in 2016 due to tornadoes.
2. The failure of 500kV towers near Cressy in western Victoria during storm activity in 2020 which left two 500kV circuits out of service.

The response to transmission line failures is improving with the deployment of temporary towers used to restore power as quickly as possible, however outages can still last days or weeks in serious instances.

2.3.3 INFRASTRUCTURE RELIABILITY COMPARISON AND FUTURE TRENDS

A measure of the relative reliability of the high voltage powerlines versus gas pipelines can be made by comparing the number of loss of supply events, per kilometre of installed transmission infrastructure per annum for an equivalent period.

The comparison in Table 3 identifies that gas pipeline loss of supply scenarios (based on frequency of gas release incidents) is an order of magnitude lower compared to high voltage transmission power lines.

Table 3: Loss of supply comparison

Infrastructure	Period of Review	Approximate length	Loss of Supply Events	Event per annum (average)	Events per annum per km installed
Gas pipelines	9 years (2009-2018)[10]	39,000	**10 (9 leaks, 1 rupture)**	1.1	0.03
HV Powerlines	9 years (2010-2019)	43,000	**164**	18.2	0.42

Duration of outages following a loss of supply can be similar with incidents leading to a potential outage of hours to days for small incidents and up to weeks for larger events, such as pipeline ruptures. In general, major pipeline ruptures would still be expected to be restored to service in a shorter timeframe than major transmission tower failures, due to the extent of works required to repair and reinstall infrastructure.

[10] Note that the period of review is offset by one year due to differences in availability of incident data available publicly. Both assessments cover an equivalent nine-year duration.

Based on the standards of design and construction and the similarities expected in operating infrastructure, biogas, renewable methane and hydrogen transmission pipelines are expected to have a similar performance into the future. Although existing assets will continue to age, the inspection methods used for monitoring defect growth is expected to ensure a similar level of ongoing performance, with a substantial majority of defects identified, and repairs well before they grow to a potential size that results in a gas release. Similarly, in terms of external interference events, although urban sprawl in major cities is leading to a higher likelihood of development on or near a pipeline easement, there is an increasing level of engagement with State and Territory planning authorities to ensure that pipeline assets are identified and protected during development activities (for example, through initiatives such as the APGA Pipeline Corridor Committee).

Buried pipelines are generally protected from most natural hazards in Australia and are unlikely to result in a failure during bushfire, extreme wind, flood and other weather events. The relatively low seismicity across Australia, and lack of active fault lines where pipeline infrastructure is installed, means it is also unlikely to suffer from an increase in geohazard induced pipeline failures. Flood events can result in erosion of soil cover over buried pipelines that may require lowering of pressure and reduced supply to rectify but are less likely to result in an unplanned outage due to the inherent flexibility of steel pipeline assets.

Comparatively, overhead transmission lines by nature of their design are more exposed to natural hazard events, including strong winds that can bring down overhead lines and towers as well as bushfires that can burn through above-ground network assets. The cost of impacts from bushfire and high wind and extreme weather events are increasing and expected to continue to do so due to the impacts of climate change. This increased exposure may result in an increase in the loss of supply events into the future for high voltage overhead powerlines and may require further investment to mitigate in the future.

2.4 ENVIRONMENTAL IMPACTS

Environmental impacts are another factor to consider when comparing infrastructure investments. The community, both domestically and globally, is increasingly seeking infrastructure developments that have a lower impact on the ecosystems where they are installed, and a lower environmental footprint. This also extends to considerations to the community, including impact on cultural heritage and visual amenity. When considering gas pipelines, potential for the impact of a gas release to the environment also needs inclusion in any environmental impact assessment.

2.4.1 GAS PIPELINE ENVIRONMENTAL IMPACTS

There are a few considerations when assessing the environmental impact of gas pipelines in comparison to power lines. In most instances, the localised environmental impact during construction and after remediation of the pipeline right of way is typically lower for gas pipelines, due to the narrower construction and operating easement (typically 30m or less) and the ability for much of the seed stock to be preserved and reinstated following trenching of the pipeline.

Visual amenity disturbance during the construction period is of a similar scale for both asset types. However, during operation the visual amenity of a gas pipeline to local landholders or occupants of nearby residents, is typically minimal, given pipelines are buried assets. Following construction, the main visual identifiers of the pipeline asset are pipeline marker signs and infrequent above ground facilities (mainline valve sites, cathodic protection test points, compressor stations). Additionally, the line of cleared vegetation is likely to remain visible where major trees are unlikely to be tolerated, although grasses and other minor vegetation is typically rehabilitated. Compared to above-ground high voltage power lines, the visual impacts are substantially reduced.

Another environmental consideration for natural gas pipelines are fugitive emissions. Fugitive emissions arise from rare gas release events such as pipeline blowdowns and minor leaks from facilities. According to the CSIRO factsheet, fugitive emissions from gas production in Australia are estimated to account for about 2.5 per cent of greenhouse gas emissions. Methane is also a more potent greenhouse gas than carbon dioxide.

While most of gas industry fugitive emissions are associated with gas gathering, upstream processing, or downstream distribution networks rather than the transmission networks, the Australian pipeline industry is on record as being committed to minimising fugitive emissions which arise from their role in the gas supply chain[11]. Early analysis shows that hydrogen has global warming potential between that of carbon dioxide and methane, hence any hydrogen supply chain will need to hold fugitive emissions avoidance as a key design priority[12].

2.4.2 GAS PIPELINE SAFETY

In Australia, high pressure transmission pipelines are required to be licensed with the licensee being accountable for the safety and integrity of the pipeline. The Australian Standard (AS) 2885 has been adopted by the State and Territory governments as the single and sufficient set of requirements for oil and gas pipeline design. The standard series has a significant focus on safety management, in particular in high consequence areas where public exposure risks are greater. License obligations and the in-depth requirements under the AS 2885 series help to ensure that operating companies have suitable systems in place to manage the safety of the pipeline for its full life cycle. A key safety principle of risk assessment when designing pipelines for all environments is the 'ALARP' approach that all risks to the pipeline are to be kept as low, or any higher risks assessed as low as reasonably practicable (ALARP).

By global standards, the Australian gas and pipeline industry has an excellent record of safety performance[13], without recorded injury or fatality associated with pipeline damage incidents.

2.4.3 HIGH VOLTAGE TRANSMISSION LINE SAFETY AND ENVIRONMENTAL IMPACTS

Safety and environmental impacts of overhead transmission lines is a field which has been researched and considered extensively. The following highlights some of the key environmental and safety issues impacting overhead transmission lines which are non-existent or less significant for pipelines:

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[11] Questionnaire Response: Victorian Fugitive Emissions Survey, Australian Pipelines and Gas Association 2021 https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/apga_victorian_fugitive_emissions_study_response_.pdf

[12] Global environmental impacts of the hydrogen economy, Derwent et al 2006 http://agage.mit.edu/publications/global-environmental-impacts-hydrogen-economy

[13] https://esv.vic.gov.au/wp-content/uploads/2019/12/GPISafetyPerformanceReport2018-19.pdf

1. Visual amenity – Transmission lines can have a significant impact on the visual amenity of an area. Lines often must transit through rural or wilderness areas which further contrasts the environment, impacting heavily on visual aesthetics. The International Council on Large Electric Systems (CIGRE) in technical brochure 110 found visual impact to be the key environmental issue for overhead transmission lines.

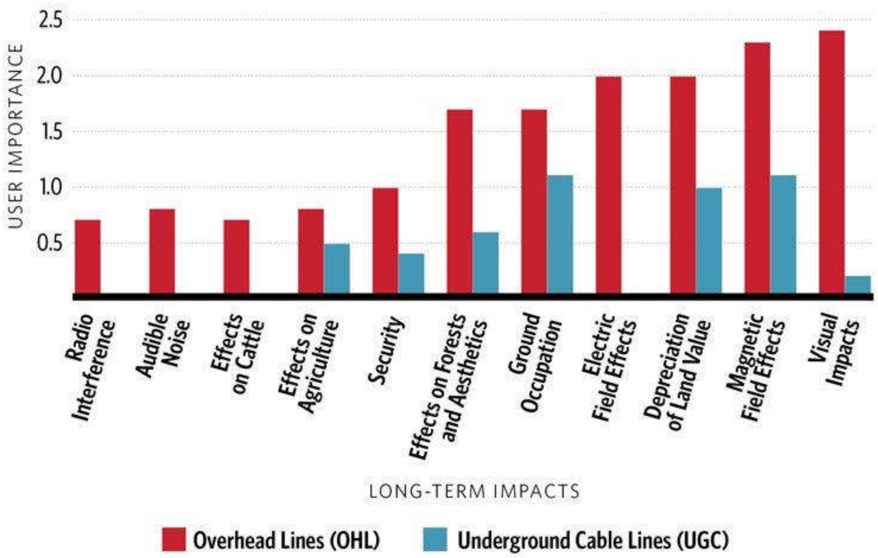


Figure 17: Transmission line impacts (CIGRE[14])

2. Width of easement – Transmission line easement widths are significant (refer Figure 10) with for example a 500kV single circuit transmission line requiring a 65m easement width in Victoria. Vegetation must be cleared from the easement and there are restrictions on activities and land usage within an easement corridor.
3. Impacts to farming activities – Traditional farming practices are not heavily impacted by an overhead transmission line, however the line does place limitation on aerial activities and use of drones which is gaining prevalence.
4. Safety of transmission lines – Transmission lines in general are very safe with significant effort put into design, operations and maintenance to ensure the safety of people and wildlife. Due to the exposed nature of overhead transmission lines and the hazard posed by high voltage electricity, the risks posed by overhead lines cannot be fully mitigated with residual risks existing around:
    a. Electrocution hazards for people or wildlife.
    b. Collision or entanglement hazards for aircraft.
    c. Risk of downed lines from traffic collisions.
    d. Electric and magnetic fields.
    e. Risk of fire or arcing.

[14] CIGRE, 1999, Technical Brochure 110, https://e-cigre.org/publication/147-high-voltage-overhead-lines-environmental-concerns-procedures-impacts-and-mitigations

f. Bushfires.

Buried electrical transmission lines may not suffer from the above issues and while it is possible to install electrical transmission lines underground, this is typically very costly. Estimates vary greatly based on terrain, soil conditions and project specifics, however burying of transmission lines is typically estimated to two to ten times[15 16] more expensive than the cost of the equivalent overhead line option.

In terms of energy storage, the safety and environmental impact of lithium-ion battery technology (the major technology in use for BESS) also needs consideration. The major hazard posed by lithium-ion battery technologies is fire, as a result of the flammability of the substances used in the battery. Most incidents occur when there's a concentration of lithium-ion cells in non-controlled storage conditions or areas. Only two per cent of lithium-ion batteries in Australia are recycled, with the majority being shipped to landfill overseas where they remain and can potentially result in a fire risk.[17] Although this recycling rate is for consumer electronics, with utility scale systems expected to be managed with greater awareness of safety and have a comparatively longer life span of 5- to 15 years, full lifecycle impacts requirement assessment and management for major installations.

2.5 ENERGY STORAGE

It is well documented that significant additional energy storage will be required as more of Australia's energy needs are met by non-dispatchable VRE. Energy storage in the NEM will be required in various durations. Short duration storage of less than four hours will be required for grid stabilisation and to smooth temporary variability in generation and demand. Longer duration storage will be required to cover extended periods of low output from VRE generation. As the NEM transitions to higher VRE, the need for cheap long duration bulk energy storage will increase rapidly.

Bulk storage of natural gas is common practice globally. In Australia, natural gas is stored at a number of sites including underground storage (in depleted gas fields) as well as in transmission pipelines via 'linepack'. Pipeline 'linepack' is where additional gas, beyond that required by the load, is injected into a long-distance gas transmission line increasing the stored gas quantity. This is sometimes achieved by oversizing the pipeline, adding additional compression or looping (duplicating) the pipeline. The stored gas can then be drawn down by dispatchable gas generators or simply to supply homes and businesses. The amount of gas which can be stored is significant. For example, the Dampier Bunbury pipeline is 1,399km in distance and looped for majority of its length with DN650 pipeline. The original DBP free flow capacity was 200 TJ/d in 1984 - over five staged expansions, adding compression and loop lines, the pipeline capacity has increased to 885 TJ/d by 2010. The throughput has accommodated both an increase in energy demand and for storage.

[15] IET & Parsons Brinckerhoff, 2012, *Electricity Transmission Costing Study*, https://www.theiet.org/impact-society/factfiles/energy-factfiles/energy-generation-and-policy/electricity-transmission-costing/
[16] ACER, Transmission Infrastructure Reference Costs, https://www.acer.europa.eu/electricity/infrastructure/network-development/transmission-infrastructure-reference-costs
[17] CSIRO, Australian Landscpe for Lithium Ion Battery Recylcing nad Reuse https://publications.csiro.au/publications/publication/PIcsiro:EP208519/SQbattery%20lithium/RP1/RS25/RORECENT/STsearch-by-keyword/LISEA/RI2/RT72

Pipeline packing, or oversizing pipelines for additional capacity, is considered a viable large scale storage solution for renewable gas pipelines as it has historically been for natural gas pipelines. Including storage typically increases the upfront capital expenditure and also ongoing operating costs compared to a transmission line sized for required throughput only, this is only due to the increased diameter and/or pressure required to accommodate the storage requirements. Most transmission pipelines are not designed for high amplitude, high frequency pressure cycling, but often have a fatigue life well in excess of the expected design life even in high cycle service[18]. Therefore, it is not typically a major design concern for natural gas pipelines used for storage.

Fatigue is a greater concern in hydrogen service and is a key design consideration for sizing hydrogen pipelines for storage. At low stress amplitudes the effect of pressure cycling is negligible, but at large stress amplitudes (the transition varies, but typically above 5 $MPa.m^{0.5}$), the effect can result in an increase in crack growth rate by a factor of 10 to 100 for hydrogen compared to natural gas, and fatigue life therefore becomes an important design criterion. Fatigue life and the importance of fatigue crack growth is further discussed in Appendix 5.

The storage of gaseous hydrogen is also more challenging as the gas has a lower density compared to natural gas – 1kg of hydrogen gas occupies 11m^3 at room temperature and atmospheric pressure. When considering hydrogen storage options, there are three main components that are most critical:

- the storage volume and pressure;
- the method of compression to reach the desired storage pressure; and
- the tolerance of the storage system to the required intermittency of the upstream production profile (i.e. turndown).

In addition to line packing, there are several alternatives for hydrogen storage that have not been explored within the Study, including liquid hydrogen, storage in a chemical carrier (such as ammonia), metal hydrides, or underground storage in salt caverns and depleted gas fields. Where a long-distance transmission pipeline is being installed, pipeline packing or oversizing is expected to be much more cost-effective than alternative storage methods, the exception may be where there is suitable natural underground storage in close proximity to the gas transmission asset.

Direct storage of electricity generated by VRE is more complicated as electricity is transient and cannot be directly stored in bulk. Electrical energy must be either used straight away or converted to a different form of energy for bulk storage. There are a number of existing and emerging storage technologies with battery energy storage system (BESS) and pumped hydro energy storage (PHES) the most mature and adopted technologies.

BESS is typically deployed to provide short-term storage for grid stabilisation or to smooth temporary variations in the generation and demand balance. Examples of BESS in Australia include the Hornsdale Power Reserve (150MW / 194MWh) and the Victorian Big Battery (300 MW / 450 MWh battery). To give context, the Victorian Big Battery with an energy storage of 450MWh is equivalent to ~1.6TJ of energy storage (approximately equal to 4hrs storage for a 10TJ/day supply chain, the smallest energy storage quantity considered in the Study). BESS has an excellent response time and a high round trip efficiency (storage with low losses), however is expensive when bulk scalable energy storage is needed.

[18] Refer to AS 2885.1 Appendix J2.1

PHES is a mature technology with the first Australian installations built in the 1970s. At times of low demand, water is pumped up hill to a top reservoir. At times of high demand, the water is allowed to fall back to a bottom reservoir via a turbine. Due to its scalability, PHES is typically suited to longer storage durations. Existing installations in Australia include the Wivenhoe Dam or the Snowy Hydro scheme. Of particular note is the Snowy Hydro 2.0 project which will provide 350TWh (or 1,260TJ) of storage.

Hydrogen as a storage medium is somewhat unique in that it provides a dual opportunity. Hydrogen gas can be converted to electricity (gas-to-power) or created from electricity (power-to-gas). This allows hydrogen to be stored and used directly as a fuel source and/or used as a storage medium for electricity.

It is likely all the above storage technologies (among other emerging technologies) will play a part in the transition to a low carbon energy system.

3 STUDY SCOPE AND CONSIDERATIONS

The Study case map uses typical Australian industry transmission distances and energy capacities, comparing the costs for natural gas, hydrogen gas, HVAC and HVDC transmission. The cases selected were specified to determine trends across a broad range of throughputs and distances, to inform which energy transmission option is most cost-effective over varying distances and throughputs. The cost comparison, presented in levelised cost of energy and storage, is discussed within the Study and comments made on any key identifications.

As many industry projects will use VRE for generation, it is expected that energy transmission rates will fluctuate with energy production. The Study will also identify the costs associated with energy storage methods for each of the carrier options to accommodate the VRE generation.

The Study considered a case matrix with 256 different process cases and configurations, each of which were translated to an equivalent electrical transmission capacity. These are detailed in Appendix 1. The case map varies across the following variables:

- Transmission carrier: natural gas, hydrogen gas, high voltage AC and high voltage DC.
- Transmission distance: 25km, 100km, 250km and 500km.
- Capacity: 10 TJ/d, 50TJ/d, 250 TJ/d and 500 TJ/d.
- Storage capacity: 0hrs, 4hrs, 12hrs and 24hrs.

3.1 SCOPE BOUNDARIES

The Study's objective was to perform a generic analysis of energy transmission, which avoids tying a transmission scenario to upstream generation or downstream use, the benefit being the data is not fixed to specific scenarios. As a result, the levelised cost figures do not consider supply chain elements beyond the transmission section, which will impact the levelised cost depending on upstream and downstream infrastructure. The infographics of the scope of inclusion within the study has been included in Figure 18 (Hydrogen), Figure 19 (Natural Gas) and Figure 20 (Electricity) below. The study does not consider the conversion of existing pipeline assets to be used for hydrogen transport, only construction of new assets.

Power lines and pipelines have varying capital and operating expenditures associated with the different infrastructure. Power generation and end use will also dictate the required equipment upstream and downstream of the transmission asset, typically making up majority of the overall project cost. The analysis assumes direct transportation from dedicated renewable generation to demand with no branching or off-takers.

For hydrogen pipelines, only the pipeline (for throughput and storage via packing) has been considered in the capital costs (refer to Figure 18).

GPA

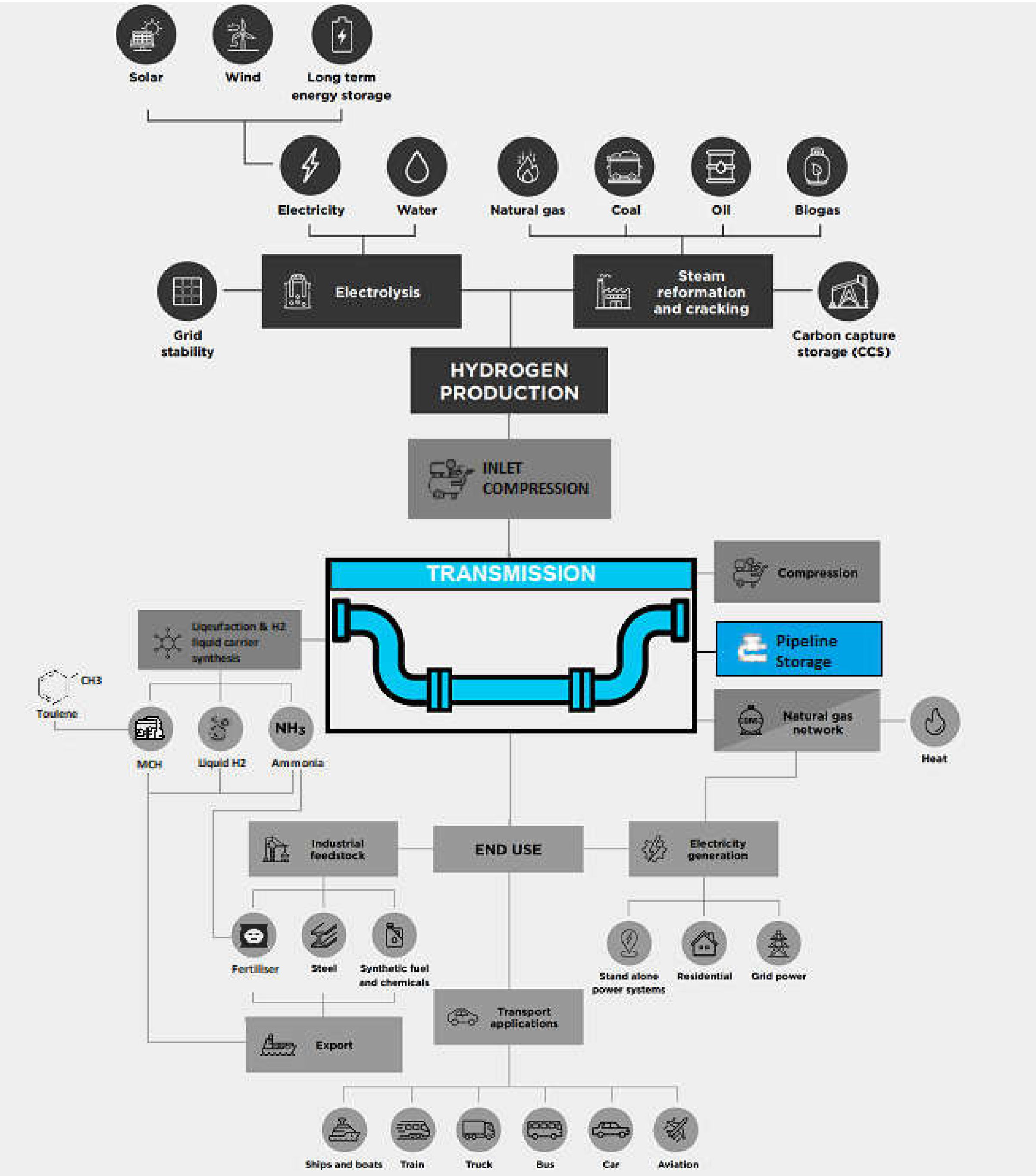


Figure 18: Scope of inclusions in renewable hydrogen gas supply chain (highlighted blue)

Similar to hydrogen, for the methane / natural gas pipelines, only the pipeline (for throughput and storage via packing) has been considered in the capital costs, (refer to Figure 19).

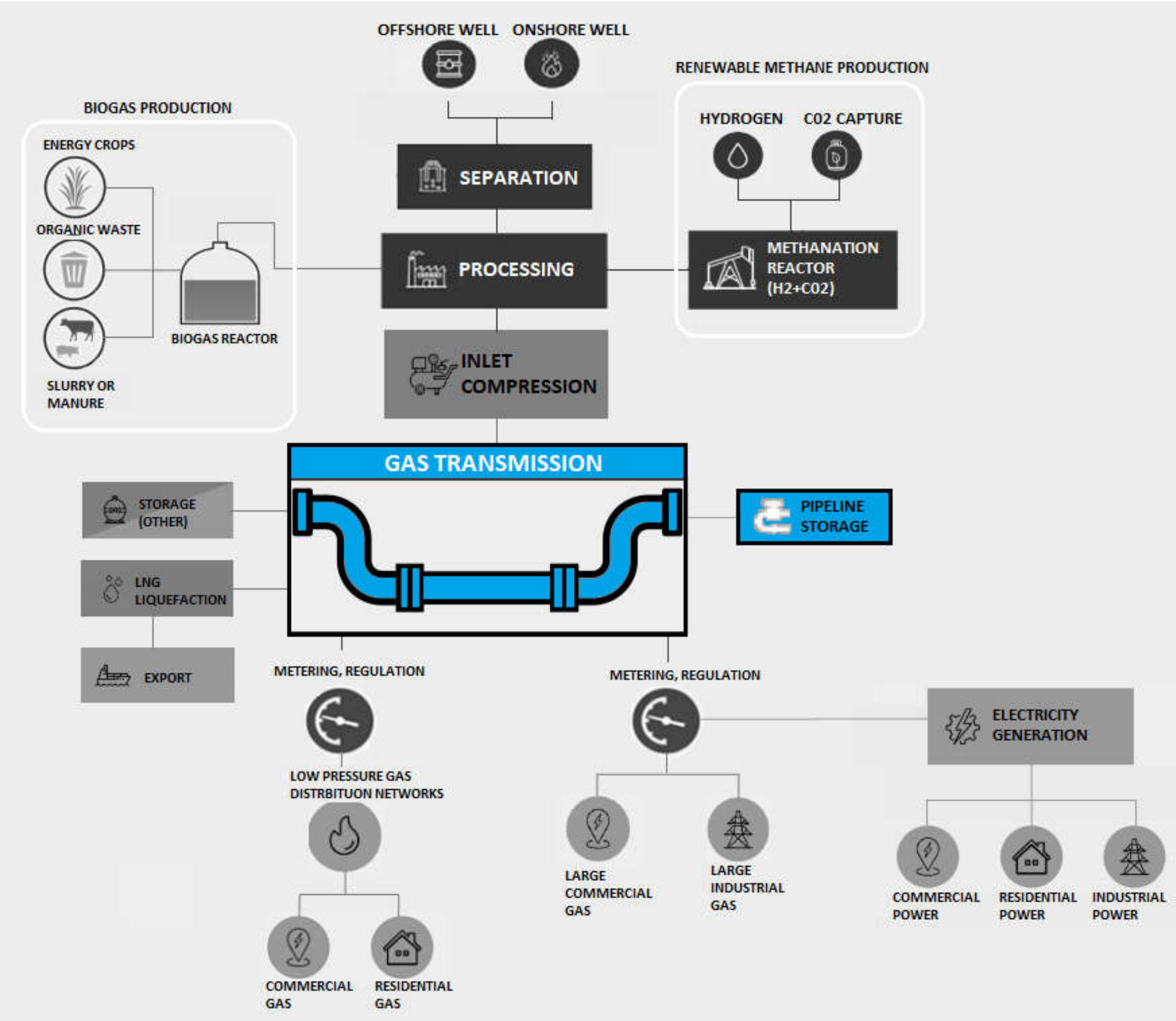


Figure 19: Scope of inclusions for natural gas, biogas and renewable methane supply chain (highlighted blue)

Scope focus for High Voltage Cases includes only the high voltage overhead transmission assets (refer to Figure 20), as well as storage via BESS and PHES for the storage scenarios (shown in the figure below).

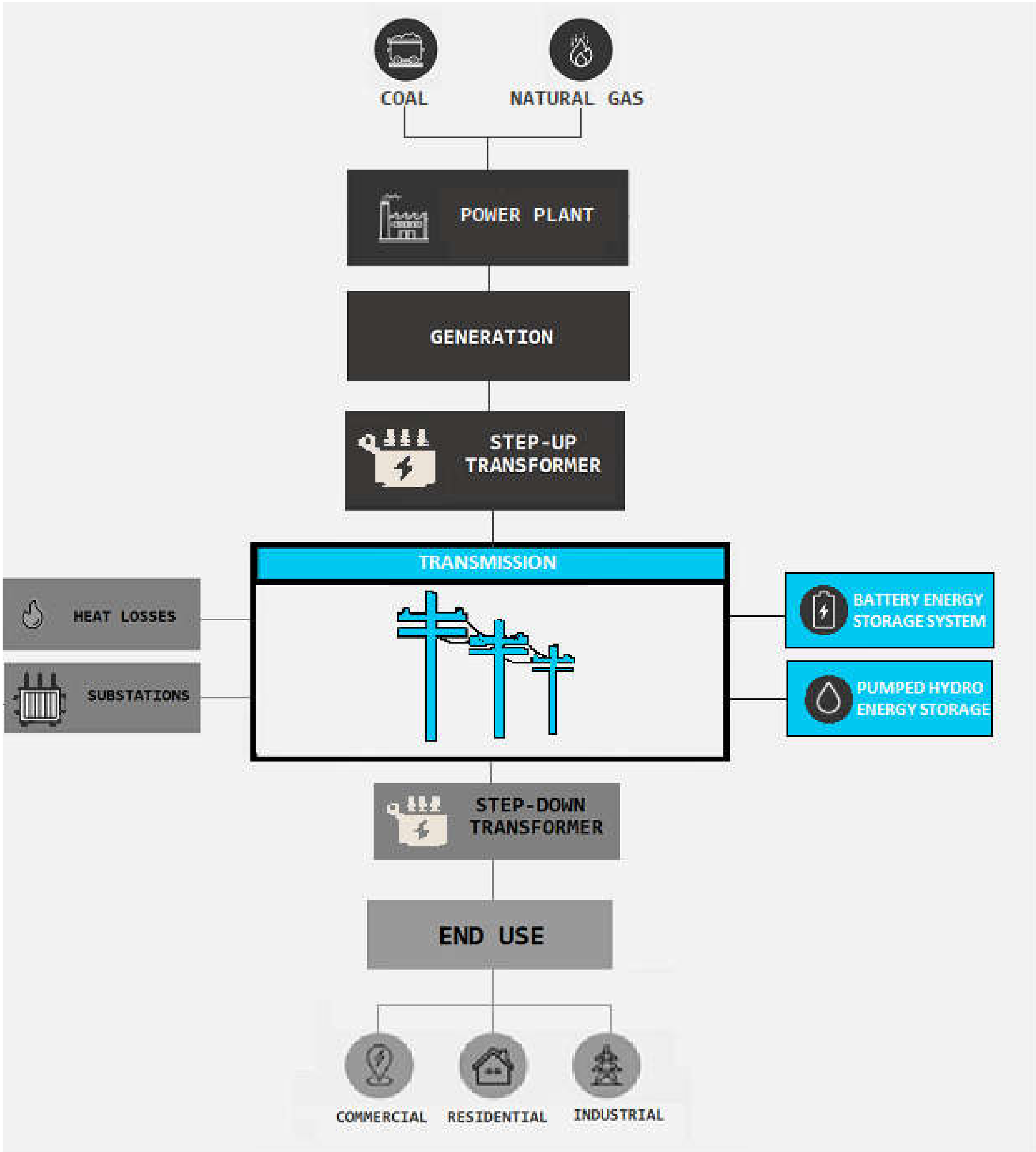


Figure 20: Scope of inclusions for electricity supply chain (highlighted blue)

3.2 STUDY APPROACH AND METHODOLOGY

First steps in the Study were to establish the case matrix (refer to Appendix 1), as well as the modelling and costing basis for each transmission type (refer to Appendix 8).

3.2.1 Case Matrix Establishment

The Australian pipeline network typically links remote gas fields to major cities and LNG export locations. Due to the size of the Australian continent, it is common to see high pressure transmission assets cover distances well in excess of 500km. Some typical Australian pipeline assets are shown in Table 1. The case map has been defined with these distances and typical range of throughputs for Australia in mind. Limitations on capacity and distance have also been set to reflect any inflection points or cost differences between transmission types.

Early in the Study, it was determined that no key findings would be made by extending the case matrix beyond 500km and 500 TJ/d. All the trends viewed within the range of 25 to 500 km and 10 to 500 TJ/d are expected to continue beyond these boundaries. An opportunity was recognised in replacing the high distance and capacity cases (1000km, 1000 TJ/d) and lowering the bottom envelope of the Study to 25km and 10TJ/d.

The lower boundaries of 25km and 10TJ/d were chosen as the focus of this study was on transmission assets. Below these limits gas pipelines are more likely to be in the distribution network setting where key assumptions applied in sizing and cost estimation in this Study start to deteriorate below these limits. Development of infrastructure in gas distribution networks is typically in an urban setting, with high population densities, and higher construction cost due to restricted access for construction and higher safety factors to satisfy no rupture requirements, which significantly alter CAPEX and OPEX estimates.

3.2.2 Pipeline Modelling

Following establishment of the case matrix, technical considerations and limitations for design were agreed and applied to modelling and costing of each case, these parameters are further discussed in Appendix 5. The parameters are defined variables and lower/upper parameters to mechanical and process design that are typical for Australian transmission and best engineering practice.

The process modelling completed determined each pipeline configuration required, including operating pressure profile, pipeline size, erosional velocities and fluid velocities. The process modelling methodology and results are included in Appendix 2 and summarised in Table 4.

Table 4: Summary of pipeline design conditions

Natural Gas	
Design Standard	AS 2885.1
Design Factor	0.72
Line Pipe Material	API 5L Grade X65 PSL2 Carbon Steel
Pipeline Diameter Range	4 – 46”
Wall Thickness Range	3.20mm - 31.80mm (above 31.80 considered custom)
MAOP	15.3 MPag

Hydrogen Gas	
Design Standard	ASME B31.12 / AS 2885.1
Design Factor	0.5
Line Pipe Material	API 5L Grade X52 PSL2 Carbon Steel
Pipeline Diameter Range	4 – 46”
Wall Thickness Range	3.20mm - 31.80mm (above 31.80 considered custom)
MAOP	12 MPag

3.2.3 Pipeline Cost Estimation

Once the pipeline cases were modelled and line pipe scenarios confirmed, the second objective was to estimate CAPEX and OPEX.

For each pipeline case a wall thickness for pressure containment was calculated using AS 2885.1 methodology (and ASME B31.12 for hydrogen) with the applicable design factors listed above. The wall thickness has been rounded up to the nearest standard ASME B36.10 pipe thickness. The wall thickness was then used to calculate a tonne/metre rate for each pipeline case and a $/tonne rate for procurement.

The overall CAPEX was then determined based on several factored norms and industry rules of thumb for construction and engineering costs. OPEX cost estimation was also determined by adjusting industry norms, factored from the CAPEX estimate. The methodology for costing each pipeline case can be found in Appendix 8.

To quantitatively examine the cost of long-distance transfer of energy, the levelised cost of energy in $AUD/GJ has been estimated based on the CAPEX and OPEX for each case. The levelised cost of storage has been separated from the cost model in order to analyse the cost of storage separately.

The results for CAPEX, OPEX and levelised cost can be found in Appendix 3 and the results discussed in section 4.

4 RESULTS

The comparison has been undertaken to review the optimal distances and throughputs for each new transmission infrastructure type. The primary objective is to establish where hydrogen transmission is on the cost curve compared to natural gas transmission and powerline options. Power lines and pipelines have been compared with no upstream generation considered, nor any downstream processing or use. Therefore, the levelised cost curves converge at $0 per GJ at 0km distance, although in reality this is not the case. As distances increase, the gradients of the cost curves are assumed to be an accurate prediction of cost of energy transport in each carrier form.

To effectively analyse the costs of energy transport associated with each carrier type, the costs have been compared by filtering different variables. First, pipelines and powerlines have been compared holistically to aid the question of which is a more affordable energy transport solution. Additionally, to gain an understanding of cost of gas transmission infrastructure, natural gas and hydrogen gas options have been compared only.

As a secondary analysis, trends in capacity of transported energy were analysed in an attempt to gauge the economies of scale with larger capacity transmission scenarios. The variables that impact the cost of energy storage were also explored; how storage costs vary with distance, capacity and amount of storage required. Finally, it was explored whether there is a benefit in midline compression over a 500km distance.

It is always expected that cost of transport will increase with distance, and this is reflected in all figures, but the Study results show how much this cost increases for each energy transport type, as well as more specific trends across distance and capacity. The cost comparison is based on the levelised cost of transport and storage ($AUD/GJ or $AUD/MWh). The cost modelling assumptions are summarised in Appendix 8.

4.1 Levelised Cost of Energy Transmission

This section discusses the levelised cost results for all transmission scenarios, with a focus on identifying trends and key observations for the following comparisons:

Section 4.1.1	Technology types – pipelines and wires
Section 4.1.2	Pipeline technology types – hydrogen and natural gas
Section 4.1.3	Capacity scenarios– 10, 50, 250 and 500 TJ/d
Section 4.1.4	Distance scenarios – 25, 100, 250 and 500km
Section 4.1.5	Storage capacities – 0, 4, 12 and 24 hours of storage capacity
Section 4.1.6	Sensitivity to midline compression

4.1.1 Pipelines vs powerlines comparison

As capacity and distance increase, pipelines (both natural gas and hydrogen) become more cost-effective when compared to electricity powerline options. This finding also applies to storage capacity, which is increasingly more costly for electricity based options of BESS and PHES and improves over distance with pipelines (as shown in Appendix 3C,), results in table form can be found in Appendix 3A).

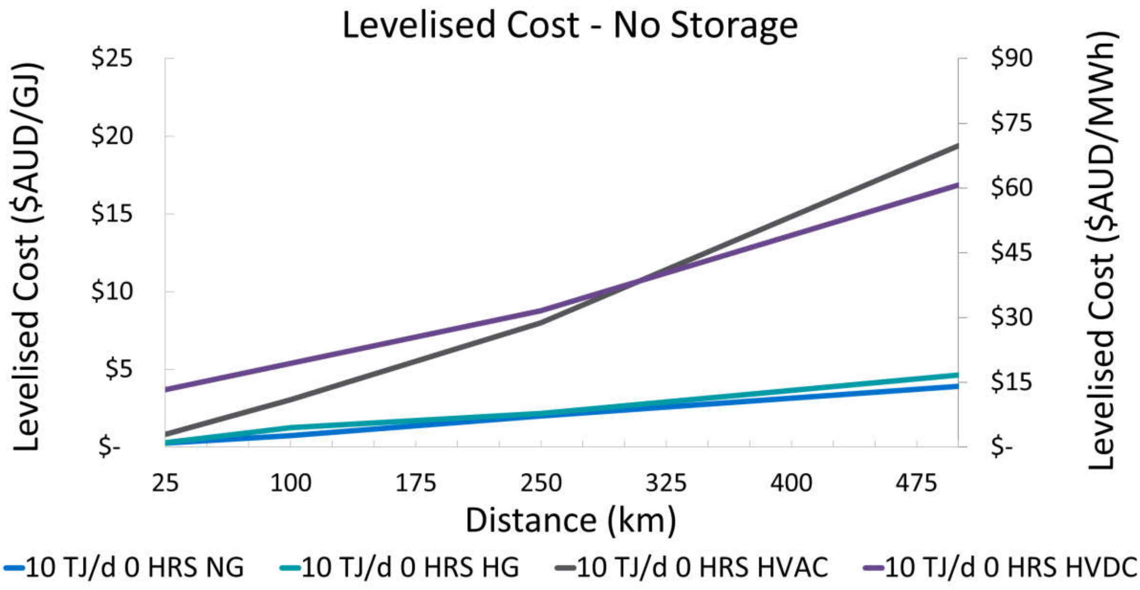


Figure 21: Levelised cost of transport (no storage) at 10 TJ/d

The results do not show a scenario where powerline transmission is a more cost-effective solution than gas pipelines, even for the smallest case example of 25km and 10 TJ/d. This may be in part due to the choice to limit the scope to 25km and 10 TJ/d. As noted in Section3.2.1, these limits were implemented as design assumptions which hold for pipeline infrastructure above these values begin to be less applicable at shorter distances. If the practicalities of designing smaller, shorter infrastructure were brought into the broader set of assumptions, different results may arise below these limits.

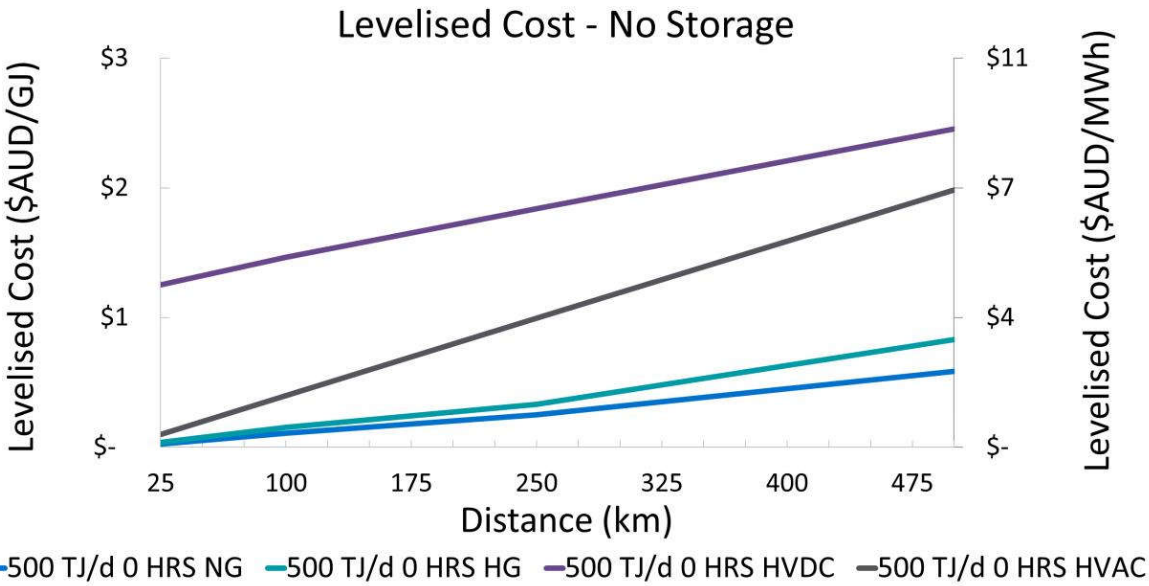


Figure 22: Levelised cost of transport (no storage) at 500 TJ/d

4.1.2 Natural Gas Vs Hydrogen Pipeline Comparison

As expected, the cost of hydrogen gas transmission is greater than that of natural gas, but still well below the power line scenarios. The trends are consistent with a marginal increase in levelised cost for hydrogen transmission across the capacity range from 10TJ/d to 500 TJ/d as shown below. Only the 50 TJ/d and 500 TJ/d trends have in Appendix 3D graphs for clarity.

The levelised cost improves as throughput increases due to economies of scale, as shown in Appendix 3D (with the exception of the 25km length with storage), results in table form can be found in Appendix 3A. The 500 TJ/d, 25km long, storage scenarios do not have the pipeline volume to accommodate the storage capacity as pipeline volume increases with length, therefore a greater diameter increase is required. This directly increases the levelised cost and does not align with the general trend of "higher throughput, lower levelised cost of energy per GJ".

It should also be noted that cycling frequency wasn't defined for the Study. If a hydrogen pipeline was expected to accommodate high cycle, high amplitude pressure cycling, it is expected more mitigation methods to manage fatigue threats would be required over natural gas. This may include greater wall thickness / lower stress, or an increased diameter, and increased costs with greater in-line inspection frequency, both contributing to a higher CAPEX and OPEX.

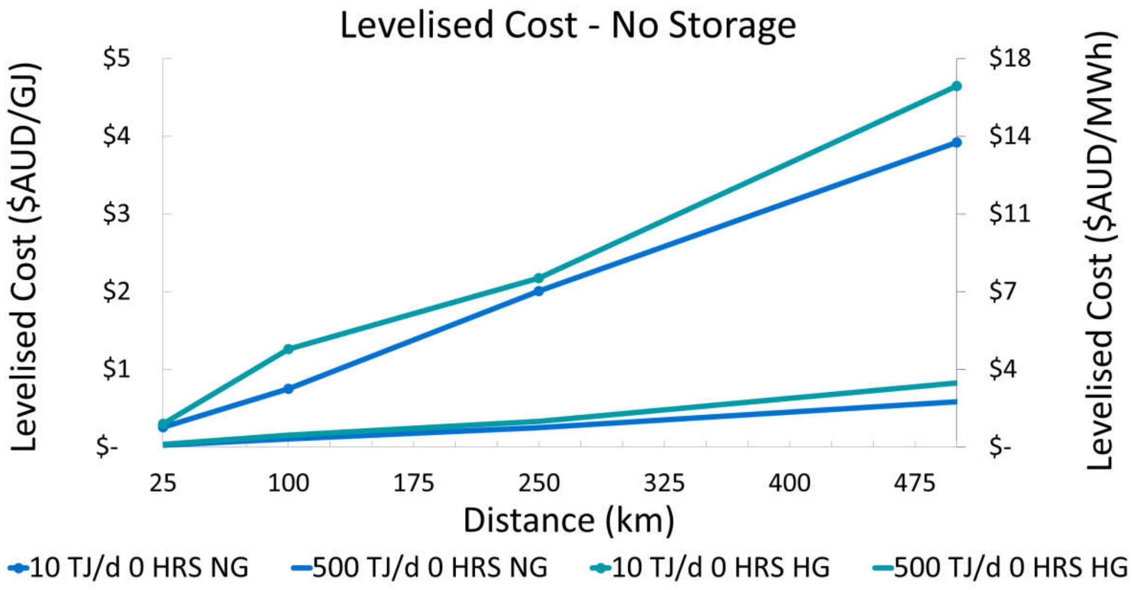


Figure 23: Levelised cost of transport (no storage) natural gas and hydrogen only

A primary consideration for cost of transport (and storage) of natural gas compared to hydrogen is the gas density, a hydrogen pipeline will be larger than its natural gas comparison for the equivalent process throughput, unless pressure is dramatically increased, this is also the case for storage capacity. This is reflected in the cost comparison of the two energy transmission types in Table 5.

A second consideration for the cost difference between hydrogen and natural gas pipelines is the higher safety factor required for hydrogen service – a reduction in design factor from 0.72 (natural gas) to 0.5 (hydrogen) correlated directly to an increase in wall thickness required. The comparatively lower material strength (X52) used for the hydrogen cases also increase cost due to greater wall thickness being required. Higher strength materials that are acceptable for natural gas, such as X65, may become more viable in the future following further research, with potential to reduce material costs with reduced steel tonnage.

Future research and commercial development have the potential to reduce the safety factor currently applied for hydrogen pipelines. It is probable that both design factor and steel grade limitations will be assessed more definitively within the next five years, due to the combined focus on research in this sector domestically and internationally.

Table 5: Percentage cost increase from natural gas to hydrogen for no storage cases

Energy Value (GJ/d)	Transmission Length (km)	Levelised Cost Natural Gas ($AUD/GJ)	Levelised Cost Hydrogen ($AUD/GJ)	Difference in Levelised Cost ($AUD/GJ)	Increase from Natural Gas to H2
10,000	25	$ 0.26	$ 0.45	$ 0.19	173%
10,000	100	$ 0.75	$ 1.26	$ 0.49	168%
10,000	250	$ 2.01	$ 2.18	$ 0.17	108%
10,000	500	$ 3.92	$ 4.64	$ 0.72	118%
50,000	25	$ 0.08	$ 0.15	$ 0.07	191%
50,000	100	$ 0.15	$ 0.48	$ 0.33	308%
50,000	250	$ 0.75	$ 0.89	$ 0.14	118%
50,000	500	$ 1.54	$ 2.16	$ 0.62	140%
250,000	25	$ 0.03	$ 0.08	$ 0.05	227%
250,000	100	$ 0.14	$ 0.22	$ 0.08	164%
250,000	250	$ 0.34	$ 0.46	$ 0.12	133%
250,000	500	$ 0.82	$ 1.14	$ 0.32	139%
500,000	25	$ 0.03	$ 0.05	$ 0.02	209%
500,000	100	$ 0.11	$ 0.16	$ 0.05	142%
500,000	250	$ 0.25	$ 0.33	$ 0.08	132%
500,000	500	$ 0.59	$ 0.83	$ 0.24	142%

4.1.3 Trends in Capacity

Where the cost trends do not follow the same gradient, there is typically an underlying process or mechanical constraint that has been reached. Some of these include:

- Pipeline diameter (lower limit): where the pipeline capacity, or storage capacity, does not demand a pipeline diameter greater than 4”, the pipeline diameter is set at this lower limit. A smaller diameter than 4” is not possible for high pressure transmission due to set constraints (discussed in Appendix 5).
- Pipeline wall thickness (lower limit): where process conditions include relatively low pressure and small diameter combinations, the minimum thickness has been set at 3.2mm (discussed in section Appendix 5). The result is certain cases in varying throughput or storage capacity having the same pipeline diameter and thickness, that is the same CAPEX and a reduced levelised cost for the higher capacity case.
- Pipeline diameter (upper limit): where the capacity and storage requirement for the pipeline require a large volume, and where a single pipeline of 46” diameter is not satisfactory, parallel pipelines are used. Cases that require multiple pipelines tend to cause inconsistencies in the levelised costs due to additional expenses in material and construction.
- Pipeline pressure (upper limit): Both the natural gas and hydrogen pipeline case maximum allowed operating pressure (MAOP) are limited by current practice, if the pressure limits are reached, a larger pipeline will be required to meet the process requirements. Larger diameter/thinner wall pipelines are typically more expensive than smaller diameter/ thicker wall.

It is important to recognise that while all carrier options vary similarly with distance and throughput (becoming more expensive with distance and cheaper per unit energy as capacity increases) electrical transmission is more expensive across all tested scenarios. This is shown in the Appendix 3E graphs, with results in table form can be found in Appendix 3A. Unlike powerlines, a pipeline's throughput capacity for an equivalent pressure increases with a squared proportionality to the pipeline diameter. This means that the rate of increase in capacity accelerates with every inch of diameter added to pipeline design.

4.1.4 Trends over Distance

As expected, as the transmission distance increases, the cost of energy increases for all technology types. The following trends have also been identified:

- HVAC and HVDC are always a large degree more expensive for energy transmission than natural gas and hydrogen. This becomes more evident with an increase in distance, capacity and storage amount. This trend is reflected in the graphs shown in Appendix 3F and Figure 24 below, results in table form can be found in Appendix 3A.
- Across longer distances, the cost impact to accommodate extra storage becomes less due to the increased volume of the overall line to accommodate pipeline packing.

Figure 24 and Figure 25 cover the levelised cost for 50 TJ/d and 250 TJ/d only, 10 TJ/d and 500 TJ/day are shown in Figure 21 and Figure 22.

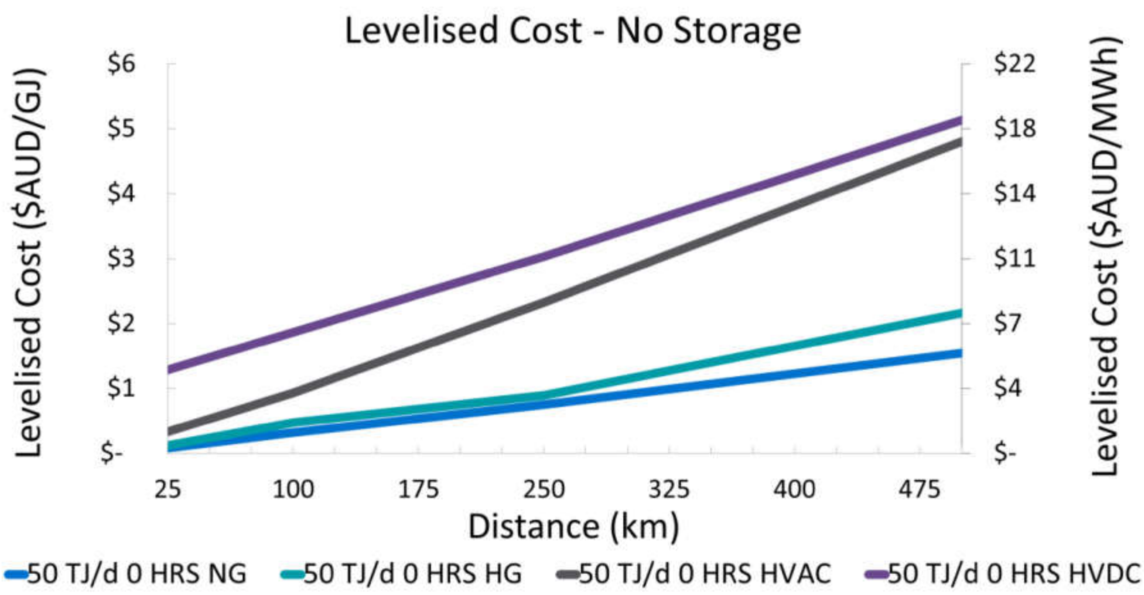


Figure 24: Levelised cost of transport (no storage) at 50 TJ/d

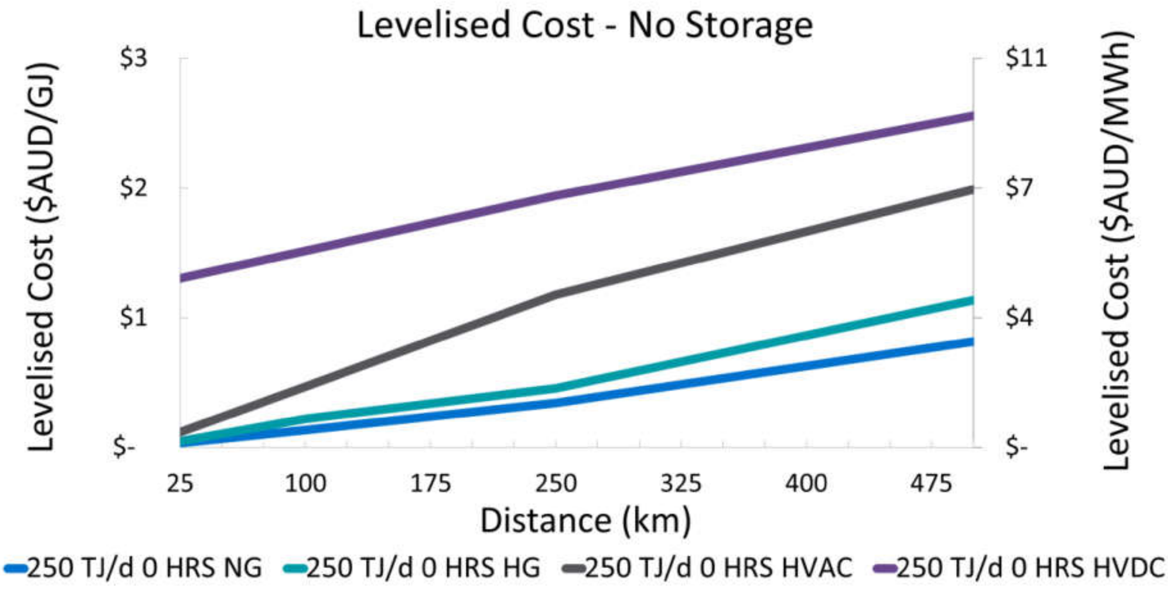


Figure 25: Levelised cost of transport (no storage) at 250 TJ/d

4.1.5 Trends in Storage

The capital cost and levelised cost of storage is governed by two primary factors:

- The storage capacity required will expectedly increase the cost of energy, with a greater diameter and/or pressure required to accommodate storage for the same distance.
- As distance increases and the pipeline becomes more expensive, less of a diameter increase is required to accommodate storage – the volume increase is accommodated in the extra length of the pipeline rather than the additional diameter at shorter lengths.

Both of these factors cause trend lines to be inconsistent, as shown in the figures below. As a result, the trend lines show flat gradients in certain sections. This is exacerbated for hydrogen cases due to the density of gas and greater volume required to store a terajoule of energy compared to natural gas.

For example, in the natural gas 500km cases, 0, 4 and 12 hour storage can all be accommodated with a 6” or 10” pipeline for 10 TJ/d and 50 TJ/d respectively with no requirement to increase diameter. Only line pressure (which increases wall thickness slightly) needs to increase, hence the lines are on the same path in Figure 26 below. Hydrogen cases follow a similar trend for select cases.

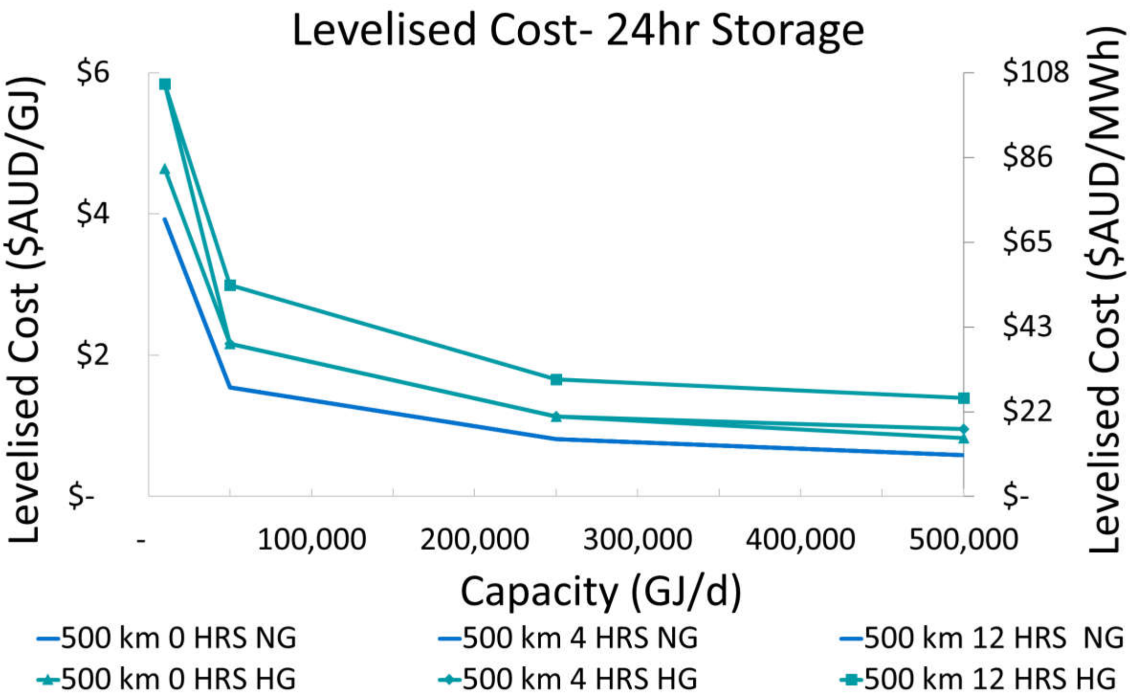
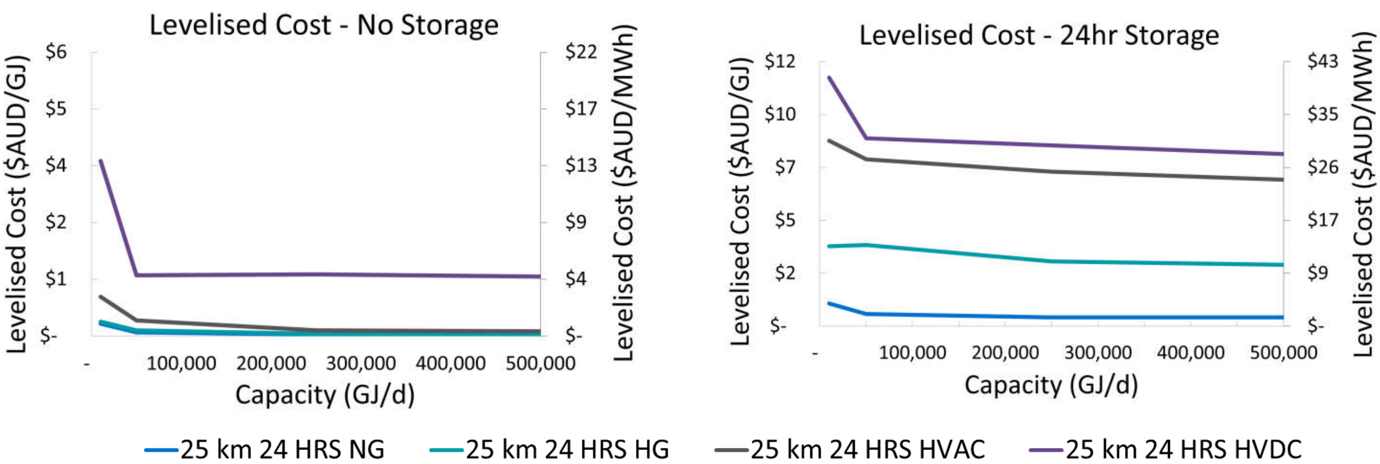


Figure 26: Levelised cost of transport (varying storage) at 500k

While less evident at lower throughputs and for lesser storage, with economies of scale, pipeline energy storage becomes much more cost-effective using the pipeline as a storage vessel when comparing to BESS or electrical storage solutions. This is rather evident in the graphs below (25km and 500km comparison for 0 and 24 hour storage).



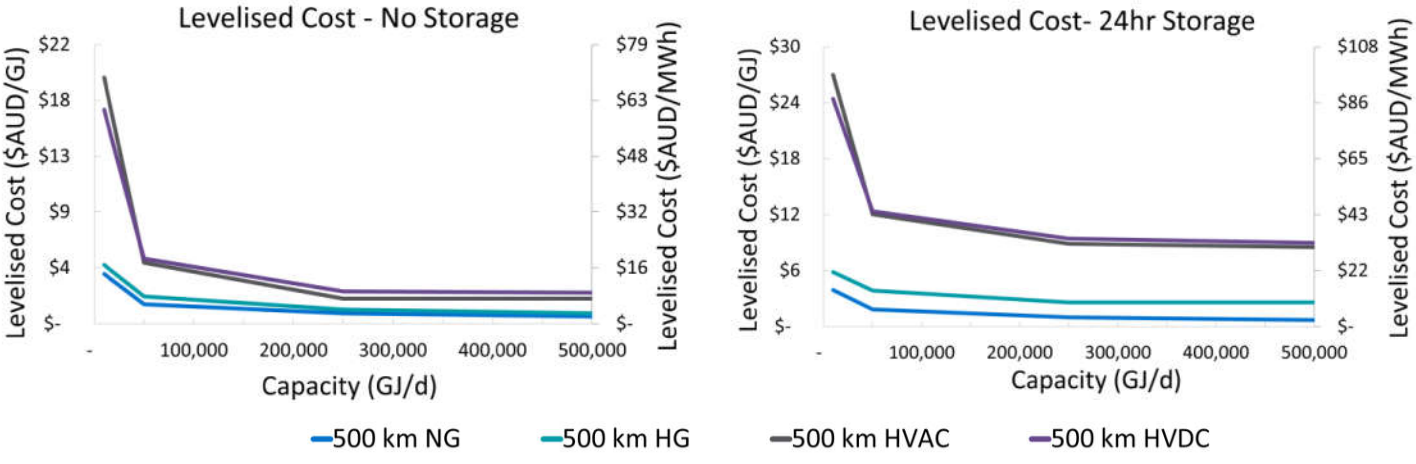


Figure 27: Levelised cost of transport (varying storage) at 500km

4.1.6 Midline Compression Sensitivities

Gas transmission often uses midline compression for long distance transmission, increasing line pressure and reducing pipeline diameter in order to save on pipeline material and construction costs. This is also beneficial where there are multiple offtakes along the length of the main pipeline supplying multiple customers. Hydrogen, compared to natural gas, has a much lower pressure drop across an equivalent distance with the same process conditions. As a result, hydrogen gas midline compression is not required until greater distance intervals.

The process simulation completed identified that for both hydrogen gas and natural gas the case requirements could be met without midline compression for all cases. This was implemented across the case matrix for a fair comparison of cost of transmission. As a sensitivity, a few 500km case examples were estimated with midline compression included at the 250km interval – the results shown in the figure below suggest that midline compression would only increase the overall transmission cost.

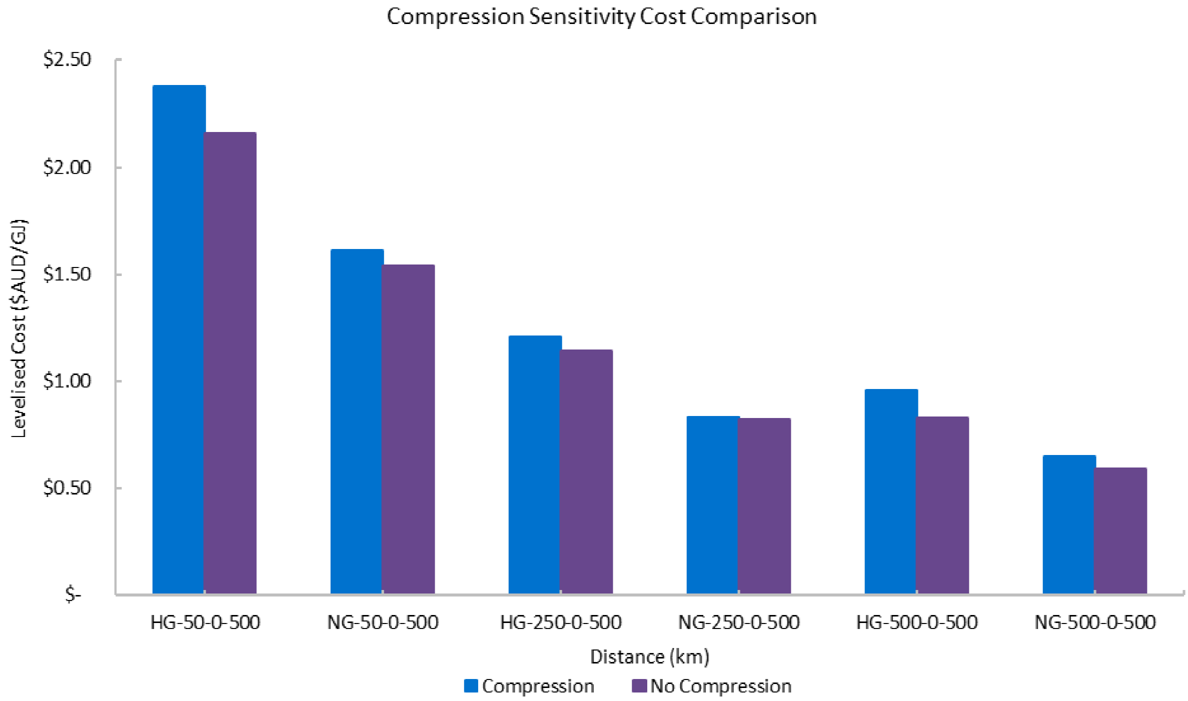


Figure 28: Comparison of 500km cases midline compression against no midline compression

Table 6: Comparison of midline compression sensitivities data

Case	Compression (Yes/No)	TOTAL CAPEX ($Audmil)	COMPRESSOR CAPEX ($Audmil)	Power Consumption ($Audmil)	Annual OPEX - Year 0 ($Audmil)	Levelised Cost ($AUD/GJ)
HG-50-0-500	Yes	$415,400,000	$17,600,000	$4,300,000	$12,100,000	$2.38
HG-50-0-500	No	$468,800,000	$-	$-	$9,400,000	$2.16
NG-50-0-500	Yes	$327,000,000	$9,900,000	$800,000	$7,700,000	$1.61
NG-50-0-500	No	$324,600,000	$-	$-	$7,400,000	$1.54
HG-250-0-500	Yes	1,118,700,000	$85,100,000	$8,400,000	$29,400,000	$1.21
HG-250-0-500	No	1,230,200,000	$-	$-	$24,700,000	$1.14
NG-250-0-500	Yes	$800,600,000	$49,400,000	$3,700,000	$20,600,000	$0.83
NG-250-0-500	No	$858,000,000	$-	$-	$19,400,000	$0.82
HG-500-0-500	Yes	1,685,700,000	$170,100,000	$16,800,000	$48,400,000	$0.96
HG-500-0-500	No	1,798,100,000	$-	$-	$36,000,000	$0.83
NG-500-0-500	Yes	1,206,300,000	$98,700,000	$7,300,000	$32,800,000	$0.65
NG-500-0-500	No	1,231,500,000	$-	$-	$27,800,000	$0.59

Although the size of the pipeline decreases with midline compression (as shown in the figure below), it does not offset the additional cost enough to warrant it. There are also unaccounted costs in the high-level estimate, such as power loss, redundancy, additional maintenance and more. The cost difference would be greater at the smaller length case examples as the diameter (increasing material and construction costs) has a bigger impact on the overall cost with an increase in distance, whereas the midline compression cost does not vary significantly with distance (the pressure increase required from suction to discharge will reduce only).

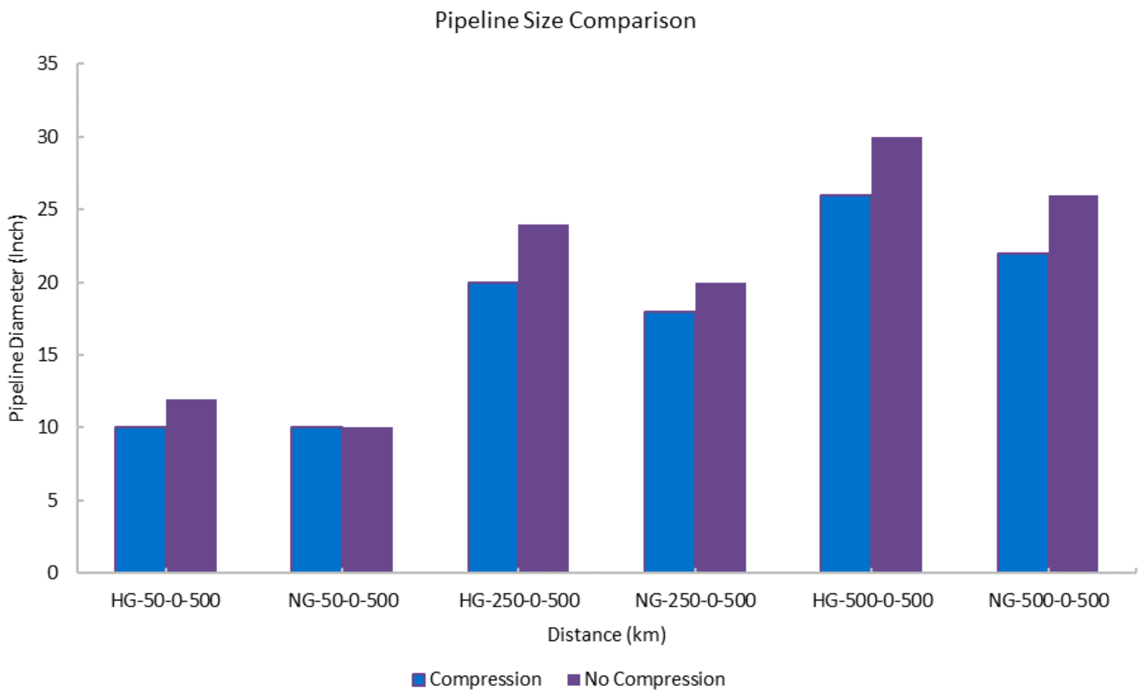


Figure 29: Comparison of pipeline sizes for midline compression against no midline compression

4.2 Levelised Cost of Storage

Energy storage in gas pipelines is possible due to the compressible nature of gases. Loosely speaking, for each specific flow rate and inlet or outlet pressure combination for a pipeline there is a correlated volume of gas held within the pipe to allow flow to occur. For a given flow rate, there is more gas stored in the pipe if pressures are higher than if pressures are lower. So long as the pipeline is not at flow capacity, it is possible for gas to be stored between the minimum and maximum pressure profiles for a given flow rate.

This is referred to in the industry as gas storage in the form of "linepack", discussed in section 2.5. A pipeline that is designed to operate at flow capacity has little to no room to vary its pressure profile, hence has no readily accessible energy storage. In the design process, a pipeline which is first designed to operate at flow capacity can have its diameter increased, in turn resulting in reduced flowing pressure profile. This opening to the possibility of storing energy between the maximum and minimum flow profile for the designed flow rate.

This was the approach taken to determine the additional CAPEX required to allow pipelines to both transport energy at a certain rate and have room to store a certain volume of energy at the same time. By having designed the zero-storage case in order to determine outcomes in Section 4.1, the difference in cost (and any associated increase in OPEX) between a storage case and a no storage case can be used to determine the levelised cost of energy storage in a pipeline. The tariff provided through this process is referred to as 'Park' or 'Park and Loan' services in existing pipelines, and represents a low-cost form of gaseous energy storage today[19].

The levelised cost of storage required has been separated, and provided as a tariff cost to provide a storage capacity (in terajoules) based on the number of hours required per day, across the life of the asset. Storage capacities across the case map are shown in the table below in order to determine each case rate in $AUD/TJ/d or $AUD/MWh/d. A summary of the results can be seen in Figure 30 and Figure 31 with the detailed results for cost of storage in Appendix 3B.

Table 7: Storage capacities across case map (Terajoules/d)

Storage Duration	10 TJ/d	50 TJ/d	250 TJ/d	500 TJ/d
4 hr	1.7	8.3	41.7	83.3
12 hr	5	25	125	250
24 hr	10	50	250	500

From initial analysis, it is clear that the cost of HVAC and HVDC storage is much greater than the cost of pipeline packed energy storage, even compared to hydrogen.

The electrical cost of storage doesn't vary with distance. A separate installation must always be built to the transmission line. Similarly to the trend recognised with the ability of a pipeline to accommodate an increase in capacity due to the throughput increasing with a squared proportionality to the pipeline diameter, this is the case for storage capacity as well. Although, the storage capacity increases with cubed proportionality as the pipeline length is also an influence on storage, unlike throughput which is only dependent on pipe cross-sectional area. The longer the pipeline length and larger the diameter, the easier it is to accommodate the additional storage capacity, this is not a trend with electrical storage as reflected in the Figure 30 below.

In some low storage capacity cases, there is no requirement to increase pipeline diameter or wall thickness to accommodate the storage capacity, therefore the storage tariff is $0/GJ/d or $0/MWh/d.

[19] Gas inquiry 2017-2025 January 2021 Interim Report, Australian Competition & Consumer Commission 2021 https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202021%20interim%20report_3.pdf

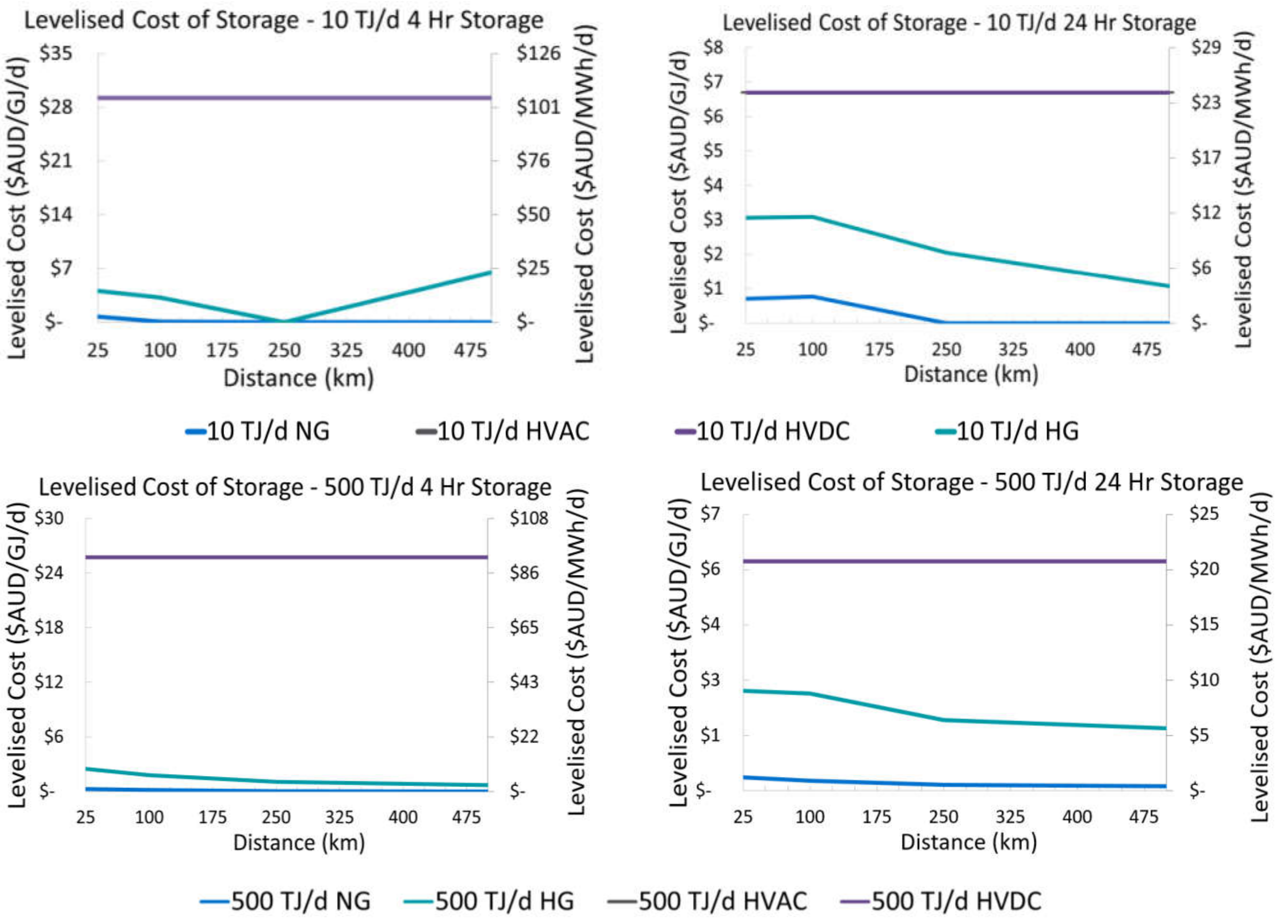


Figure 30: Levelised cost of storage (varying storage) for 10 and 500 TJ/d

The cost margin between hydrogen and natural gas storage is greater than the overall levelised cost comparison due to the energy density of hydrogen – typically for an equivalent energy storage of both technologies, hydrogen would require more volume to accommodate the capacity. This is reflected in the Figure 31 below.

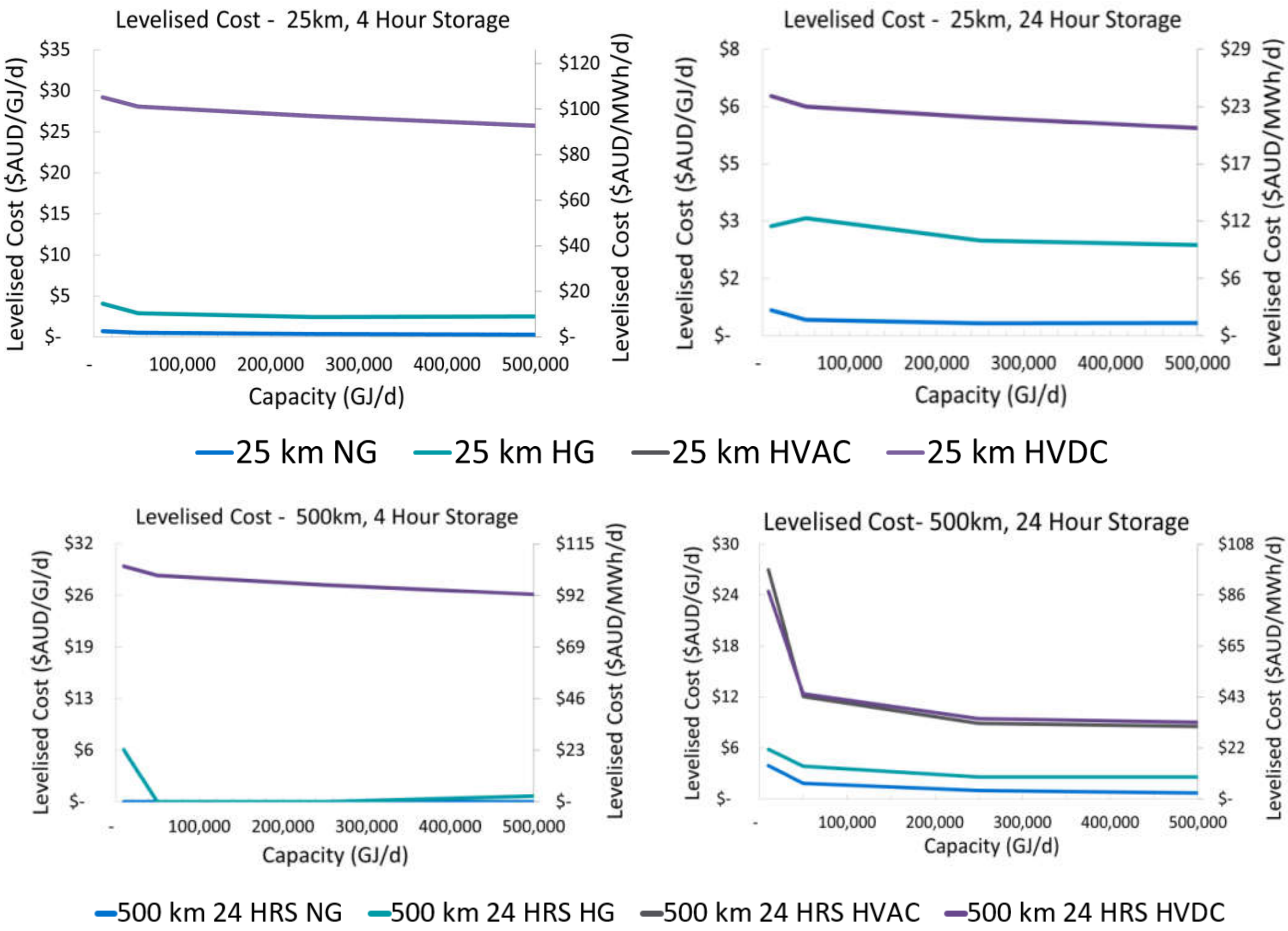


Figure 31: Levelised cost of storage (varying storage) at 25 and 500km

It is worth noting that in some levelised cost of storage cases, especially cases considering small volumes of energy storage or long distances, the levelised cost of storage is zero. This is due to the Study using standard design practice, which includes the standard design practice of considering line pipe diameters in two-inch increments. Zero levelised cost of energy simply suggests that the size of pipe to safely transport the specific flow rate over the specific distance was not doing so at flow capacity, and that as a result there was sufficient storage capacity already in the pipeline designed for the zero-storage case. For the avoidance of doubt, reducing pipeline diameter by the standard design increment of two inches in these cases would have resulted in the flow capacity of the pipeline being below zero-storage design case throughput requirement.

5 CONCLUSION

The Study confirms that, across a wide range of length and capacity scenarios, energy transport and storage via pipeline infrastructure is more cost-effective than energy transport via powerlines and energy storage in BESS and PHES. Due to differences in safety factors, current material strength limits under ASME B31.12 and energy density, hydrogen pipelines cost more to transport and store energy than natural gas pipelines. That said, the higher cost of hydrogen energy transport and storage remains significantly less than energy transport via HVAC or HVDC powerlines, and the energy storage cost of BESS or PHES.

The major reason for their cost competitiveness is that pipelines have physical advantages. The capacity of a pipeline increases exponentially with every inch of diameter added to the pipeline. Pipelines also have the advantage that they transport compressible gases. This means pipelines can be used as storage, with increasing pressure enabling increased storage capacity.

The fact that lower cost energy transport and storage can be achieved via pipeline infrastructure should be a key factor in decisions about the optimum infrastructure configuration of renewable energy projects. This is especially important where the end use is remote from the generation source or where gaseous fuel is part of the value chain. A pathway to reducing energy transport costs by 45 to 76 per cent and energy storage costs by 49 to 100 per cent for any proportion of a future net-zero energy system supports achieving the least cost net-zero future. These findings of the transmission sector, support other broader industry analysis which indicates that the least cost pathway to gas use decarbonisation is through the uptake of renewable gases. Considering only zero carbon electricity, in isolation to renewable gases and pipeline infrastructure would lead to much higher transmission infrastructure costs to deliver the new energy.

The results produced within this report are important considering the energy transport and storage aspects of an energy value chain. While the analysis undertaken here is high level, it is a good starting place from which to consider the most cost-effective form of energy transport ahead of undertaking more detailed engineering analysis on specific projects or for whole of energy system policy analysis.

Powerlines will have a place in servicing the growing electricity demand sector. However, the results from the Study show that where gaseous energy can be part of the energy value chain, energy transport and storage via pipeline infrastructure is a more cost competitive option.

APPENDIX 1 CASE MATRIX FULL

Transmission Infrastructure Type	Energy medium code	Energy Throughput Capacity (TJ/d)	**Base transmission cases** (storage capacity not required)			
			Length: 25 km Case No.	Length: 100 km Case No.	Length: 250 km Case No.	Length: 500 km Case No.
Buried **natural gas** pipeline (NG)	NG	10	NG-10-0-25	NG-10-0-100	NG-10-0-250	NG-10-0-500
	NG	50	NG-50-0-25	NG-50-0-100	NG-50-0-250	NG-50-0-500
	NG	250	NG-250-0-25	NG-250-0-100	NG-250-0-250	NG-250-0-500
	NG	500	NG-500-0-25	NG-500-0-100	NG-500-0-250	NG-500-0-500
Buried 100% gaseous **hydrogen** pipeline (HG)	HG	10	HG-10-0-25	HG-10-0-100	HG-10-0-250	HG-10-0-500
	HG	50	HG-50-0-25	HG-50-0-100	HG-50-0-250	HG-50-0-500
	HG	250	HG-250-0-25	HG-250-0-100	HG-250-0-250	HG-250-0-500
	HG	500	HG-500-0-25	HG-500-0-100	HG-500-0-250	HG-500-0-500
Overhead high voltage **alternating current** powerline (HVAC)	AC	10	AC-10-0-25	AC-10-0-100	AC-10-0-250	AC-10-0-500
	AC	50	AC-50-0-25	AC-50-0-100	AC-50-0-250	AC-50-0-500
	AC	250	AC-250-0-25	AC-250-0-100	AC-250-0-250	AC-250-0-500
	AC	500	AC-500-0-25	AC-500-0-100	AC-500-0-250	AC-500-0-500
Overhead high voltage **direct current** powerline (HVDC)	DC	10	DC-10-0-25	DC-10-0-100	DC-10-0-250	DC-10-0-500
	DC	50	DC-50-0-25	DC-50-0-100	DC-50-0-250	DC-50-0-500
	DC	250	DC-250-0-25	DC-250-0-100	DC-250-0-250	DC-250-0-500
	DC	500	DC-500-0-25	DC-500-0-100	DC-500-0-250	DC-500-0-500

Transmission Infrastructure Type	Energy medium code	Energy Throughput Capacity (TJ/d)	Required storage duration: **4 hours**				Required storage duration: **12 hours**				Required storage duration: **24 hours**			
			Length: 25 km Case No.	Length: 100 km Case No.	Length: 250 km Case No.	Length: 500 km Case No.	Length: 25 km Case No.	Length: 100 km Case No.	Length: 250 km Case No.	Length: 500 km Case No.	Length: 25 km Case No.	Length: 100 km Case No.	Length: 250 km Case No.	Length: 500 km Case No.
Buried **natural gas** pipeline (NG)	NG	10	NG-10-4-25	NG-10-4-100	NG-10-4-250	NG-10-4-500	NG-10-12-25	NG-10-12-100	NG-10-12-250	NG-10-12-500	NG-10-24-25	NG-10-24-100	NG-10-24-250	NG-10-24-500
	NG	50	NG-50-4-25	NG-50-4-100	NG-50-4-250	NG-50-4-500	NG-50-12-25	NG-50-12-100	NG-50-12-250	NG-50-12-500	NG-50-24-25	NG-50-24-100	NG-50-24-250	NG-50-24-500
	NG	250	NG-250-4-25	NG-250-4-100	NG-250-4-250	NG-250-4-500	NG-250-12-25	NG-250-12-100	NG-250-12-250	NG-250-12-500	NG-250-24-25	NG-250-24-100	NG-250-24-250	NG-250-24-500
	NG	500	NG-500-4-25	NG-500-4-100	NG-500-4-250	NG-500-4-500	NG-500-12-25	NG-500-12-100	NG-500-12-250	NG-500-12-500	NG-500-24-25	NG-500-24-100	NG-500-24-250	NG-500-24-500
Buried 100% gaseous **hydrogen** pipeline (HG)	HG	10	HG-10-4-25	HG-10-4-100	HG-10-4-250	HG-10-4-500	HG-10-12-25	HG-10-12-100	HG-10-12-250	HG-10-12-500	HG-10-24-25	HG-10-24-100	HG-10-24-250	HG-10-24-500
	HG	50	HG-50-4-25	HG-50-4-100	HG-50-4-250	HG-50-4-500	HG-50-12-25	HG-50-12-100	HG-50-12-250	HG-50-12-500	HG-50-24-25	HG-50-24-100	HG-50-24-250	HG-50-24-500
	HG	250	HG-250-4-25	HG-250-4-100	HG-250-4-250	HG-250-4-500	HG-250-12-25	HG-250-12-100	HG-250-12-250	HG-250-12-500	HG-250-24-25	HG-250-24-100	HG-250-24-250	HG-250-24-500
	HG	500	HG-500-4-25	HG-500-4-100	HG-500-4-250	HG-500-4-500	HG-500-12-25	HG-500-12-100	HG-500-12-250	HG-500-12-500	HG-500-24-25	HG-500-24-100	HG-500-24-250	HG-500-24-500
Overhead high voltage **alternating current** powerline (HVAC)	AC	10	AC-10-4-25	AC-10-4-100	AC-10-4-250	AC-10-4-500	AC-10-12-25	AC-10-12-100	AC-10-12-250	AC-10-12-500	AC-10-24-25	AC-10-24-100	AC-10-24-250	AC-10-24-500
	AC	50	AC-50-4-25	AC-50-4-100	AC-50-4-250	AC-50-4-500	AC-50-12-25	AC-50-12-100	AC-50-12-250	AC-50-12-500	AC-50-24-25	AC-50-24-100	AC-50-24-250	AC-50-24-500
	AC	250	AC-250-4-25	AC-250-4-100	AC-250-4-250	AC-250-4-500	AC-250-12-25	AC-250-12-100	AC-250-12-250	AC-250-12-500	AC-250-24-25	AC-250-24-100	AC-250-24-250	AC-250-24-500
	AC	500	AC-500-4-25	AC-500-4-100	AC-500-4-250	AC-500-4-500	AC-500-12-25	AC-500-12-100	AC-500-12-250	AC-500-12-500	AC-500-24-25	AC-500-24-100	AC-500-24-250	AC-500-24-500
Overhead high voltage **direct current** powerline (HVDC)	DC	10	DC-10-4-25	DC-10-4-100	DC-10-4-250	DC-10-4-500	DC-10-12-25	DC-10-12-100	DC-10-12-250	DC-10-12-500	DC-10-24-25	DC-10-24-100	DC-10-24-250	DC-10-24-500
	DC	50	DC-50-4-25	DC-50-4-100	DC-50-4-250	DC-50-4-500	DC-50-12-25	DC-50-12-100	DC-50-12-250	DC-50-12-500	DC-50-24-25	DC-50-24-100	DC-50-24-250	DC-50-24-500
	DC	250	DC-250-4-25	DC-250-4-100	DC-250-4-250	DC-250-4-500	DC-250-12-25	DC-250-12-100	DC-250-12-250	DC-250-12-500	DC-250-24-25	DC-250-24-100	DC-250-24-250	DC-250-24-500
	DC	500	DC-500-4-25	DC-500-4-100	DC-500-4-250	DC-500-4-500	DC-500-12-25	DC-500-12-100	DC-500-12-250	DC-500-12-500	DC-500-24-25	DC-500-24-100	DC-500-24-250	DC-500-24-500

APPENDIX 2 ENERGY SUPPLY CHAIN EXAMPLE BASIS

The energy supply chain examples displayed in Figure 4 is based on the following variables and high-level cost estimates:

- Customer demand of 50TJ per day of hydrogen. This is aligned with a large pipeline gas customer today[20].
- Behind the meter VRE generation with a levelized cost of $30/MWh in line with 2018 estimates by PWC[21]
- VRE generation will be considered to have a capacity factor of 0.5. This is notably higher utility scale VRE in the NEM[22], but is conducive to a simple example in the context of the data produced by this report.
- Electrolysis will have an efficiency of 70 per cent (0.7) as per 2020 efficiency estimates for PEM electrolysers[23].
- Electrolysis cost will be set to result in hydrogen cost of $2.20/kg if taking electricity straight from the VRE source. This is aligned to CSIRO cost estimates for hydrogen production by 2030[24].
- Levelised cost of hydrogen compression of $0.55 per GJ throughput in line with midline compression costs identified in Table 5 of this report, assuming that hydrogen is produced at the same inlet pressures upon which midline compression costs were based (noting that up to 20MPa production pressure is possible with PEM electrolysers[25]).

[20] https://aemo.com.au/energy-systems/gas
[21] https://www.pwc.com.au/legal/utilityscalesolarpvprojects.pdf
[22] https://aemo.com.au/energy-systems/electricity
[23] https://www.pnas.org/content/117/23/12558
[24] https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-research-and-development
[25] https://www.sciencedirect.com/science/article/pii/S0360319917339435#bib33

APPENDIX 3 COST ESTIMATE RESULTS

GPA

APPENDIX 3A LEVELISED COST OF TRANSPORT RESULTS TABLE

Document Title	Document No. (Client / GPA)	Rev / Status
Cost Estimate - Brief Results	- 210739-REP-001	Issued for Information

Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost ($AUD)
AC-10-0-25	AC	10,000	0	25	$ 27,741,450	$ 1,216,890	$ 0.83
AC-10-0-100	AC	10,000	0	100	$ 145,200,000	$ 1,856,193	$ 3.05
AC-10-0-250	AC	10,000	0	250	$ 406,444,500	$ 3,274,289	$ 7.99
AC-10-0-500	AC	10,000	0	500	$ 1,018,325,000	$ 5,972,404	$ 19.39
DC-10-0-25	DC	10,000	0	25	$ 171,769,525	$ 2,506,642	$ 3.70
DC-10-0-100	DC	10,000	0	100	$ 254,352,025	$ 3,418,056	$ 5.39
DC-10-0-250	DC	10,000	0	250	$ 419,517,025	$ 5,240,885	$ 8.78
DC-10-0-500	DC	10,000	0	500	$ 849,067,025	$ 7,388,635	$ 16.85
HG-10-0-25	Hydrogen	10,000	0	25	$ 10,742,644	$ 402,849	$ 0.30
HG-10-0-100	Hydrogen	10,000	0	100	$ 47,428,060	$ 1,541,412	$ 1.26
HG-10-0-250	Hydrogen	10,000	0	250	$ 95,773,027	$ 1,795,744	$ 2.18
HG-10-0-500	Hydrogen	10,000	0	500	$ 201,269,061	$ 4,025,381	$ 4.64
NG-10-0-25	Natural Gas	10,000	0	25	$ 9,711,510	$ 315,624	$ 0.26
NG-10-0-100	Natural Gas	10,000	0	100	$ 29,909,327	$ 822,506	$ 0.75
NG-10-0-250	Natural Gas	10,000	0	250	$ 85,895,095	$ 1,812,387	$ 2.01
NG-10-0-500	Natural Gas	10,000	0	500	$ 164,937,843	$ 3,711,101	$ 3.92
AC-50-0-25	AC	50,000	0	25	$ 40,644,450	$ 3,308,389	$ 0.33
AC-50-0-100	AC	50,000	0	100	$ 213,848,250	$ 3,271,189	$ 0.93
AC-50-0-250	AC	50,000	0	250	$ 534,620,625	$ 8,177,972	$ 2.32
AC-50-0-500	AC	50,000	0	500	$ 1,150,000,000	$ 14,170,724	$ 4.80
DC-50-0-25	DC	50,000	0	25	$ 257,170,287	$ 6,881,178	$ 1.29
DC-50-0-100	DC	50,000	0	100	$ 379,592,037	$ 9,627,561	$ 1.87
DC-50-0-250	DC	50,000	0	250	$ 624,435,537	$ 15,120,328	$ 3.03
DC-50-0-500	DC	50,000	0	500	$ 1,184,088,037	$ 17,918,591	$ 5.14
HG-50-0-25	Hydrogen	50,000	0	25	$ 21,404,750	$ 802,678	$ 0.12
HG-50-0-100	Hydrogen	50,000	0	100	$ 89,338,981	$ 2,903,517	$ 0.48
HG-50-0-250	Hydrogen	50,000	0	250	$ 195,815,907	$ 3,671,548	$ 0.89
HG-50-0-500	Hydrogen	50,000	0	500	$ 468,743,714	$ 9,374,874	$ 2.16
NG-50-0-25	Natural Gas	50,000	0	25	$ 14,755,604	$ 479,557	$ 0.08
NG-50-0-100	Natural Gas	50,000	0	100	$ 63,453,462	$ 1,744,970	$ 0.32
NG-50-0-250	Natural Gas	50,000	0	250	$ 160,618,455	$ 3,389,049	$ 0.75
NG-50-0-500	Natural Gas	50,000	0	500	$ 324,552,823	$ 7,302,439	$ 1.54
AC-250-0-25	AC	250,000	0	25	$ 67,740,750	$ 6,164,154	$ 0.12
AC-250-0-100	AC	250,000	0	100	$ 270,963,000	$ 24,656,615	$ 0.47
AC-250-0-250	AC	250,000	0	250	$ 677,407,500	$ 61,895,566	$ 1.18
AC-250-0-500	AC	250,000	0	500	$ 1,716,099,000	$ 69,815,589	$ 1.99
DC-250-0-25	DC	250,000	0	25	$ 1,318,563,499	$ 34,106,433	$ 1.31
DC-250-0-100	DC	250,000	0	100	$ 1,500,063,499	$ 41,652,531	$ 1.52
DC-250-0-250	DC	250,000	0	250	$ 1,863,063,499	$ 56,744,727	$ 1.94
DC-250-0-500	DC	250,000	0	500	$ 2,528,563,499	$ 70,229,058	$ 2.56
HG-250-0-25	Hydrogen	250,000	0	25	$ 43,087,835	$ 1,615,794	$ 0.05
HG-250-0-100	Hydrogen	250,000	0	100	$ 207,628,672	$ 6,747,932	$ 0.22
HG-250-0-250	Hydrogen	250,000	0	250	$ 501,775,634	$ 9,408,293	$ 0.46
HG-250-0-500	Hydrogen	250,000	0	500	$ 1,230,105,466	$ 24,602,109	$ 1.14
NG-250-0-25	Natural Gas	250,000	0	25	$ 32,395,915	$ 1,052,867	$ 0.03
NG-250-0-100	Natural Gas	250,000	0	100	$ 133,864,173	$ 3,681,265	$ 0.14
NG-250-0-250	Natural Gas	250,000	0	250	$ 366,890,976	$ 7,741,400	$ 0.34
NG-250-0-500	Natural Gas	250,000	0	500	$ 857,927,458	$ 19,303,368	$ 0.82
AC-500-0-25	AC	500,000	0	25	$ 85,804,950	$ 12,204,116	$ 0.10
AC-500-0-100	AC	500,000	0	100	$ 343,219,800	$ 48,816,465	$ 0.40
AC-500-0-250	AC	500,000	0	250	$ 858,049,500	$ 122,255,675	$ 1.00
AC-500-0-500	AC	500,000	0	500	$ 3,432,198,000	$ 138,773,128	$ 1.98
DC-500-0-25	DC	500,000	0	25	$ 2,511,320,648	$ 66,954,802	$ 1.25
DC-500-0-100	DC	500,000	0	100	$ 2,874,320,648	$ 82,046,999	$ 1.47
DC-500-0-250	DC	500,000	0	250	$ 3,474,514,298	$ 110,973,328	$ 1.84
DC-500-0-500	DC	500,000	0	500	$ 4,805,514,298	$ 137,941,988	$ 2.46
HG-500-0-25	Hydrogen	500,000	0	25	$ 67,612,944	$ 2,535,485	$ 0.04
HG-500-0-100	Hydrogen	500,000	0	100	$ 291,628,325	$ 9,477,921	$ 0.16
HG-500-0-250	Hydrogen	500,000	0	250	$ 727,721,512	$ 13,644,778	$ 0.33
HG-500-0-500	Hydrogen	500,000	0	500	$ 1,798,079,214	$ 35,961,584	$ 0.83
NG-500-0-25	Natural Gas	500,000	0	25	$ 47,247,911	$ 1,535,557	$ 0.03
NG-500-0-100	Natural Gas	500,000	0	100	$ 216,760,621	$ 5,960,917	$ 0.11
NG-500-0-250	Natural Gas	500,000	0	250	$ 536,340,683	$ 11,316,788	$ 0.25
NG-500-0-500	Natural Gas	500,000	0	500	$ 1,231,499,470	$ 27,708,738	$ 0.59

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Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost ($AUD)
AC-10-4-25	AC	10,000	4	25	$ 284,227,327	$ 4,689,115	$ 6.27
AC-10-4-100	AC	10,000	4	100	$ 401,685,877	$ 5,328,418	$ 8.50
AC-10-4-250	AC	10,000	4	250	$ 662,930,377	$ 6,746,514	$ 13.44
AC-10-4-500	AC	10,000	4	500	$ 1,274,810,877	$ 9,444,629	$ 24.83
DC-10-4-25	DC	10,000	4	25	$ 428,255,402	$ 5,978,867	$ 9.14
DC-10-4-100	DC	10,000	4	100	$ 510,837,902	$ 6,890,281	$ 10.84
DC-10-4-250	DC	10,000	4	250	$ 676,002,902	$ 8,713,110	$ 14.23
DC-10-4-500	DC	10,000	4	500	$ 1,105,552,902	$ 10,860,860	$ 22.30
HG-10-4-25	Hydrogen	10,000	4	25	$ 36,976,414	$ 1,386,616	$ 1.04
HG-10-4-100	Hydrogen	10,000	4	100	$ 69,487,165	$ 2,258,333	$ 1.85
HG-10-4-250	Hydrogen	10,000	4	250	$ 95,773,027	$ 1,795,744	$ 2.18
HG-10-4-500	Hydrogen	10,000	4	500	$ 253,026,827	$ 5,060,537	$ 5.84
NG-10-4-25	Natural Gas	10,000	4	25	$ 14,755,604	$ 479,557	$ 0.39
NG-10-4-100	Natural Gas	10,000	4	100	$ 30,599,832	$ 841,495	$ 0.77
NG-10-4-250	Natural Gas	10,000	4	250	$ 85,895,095	$ 1,812,387	$ 2.01
NG-10-4-500	Natural Gas	10,000	4	500	$ 164,937,843	$ 3,711,101	$ 3.92
AC-50-4-25	AC	50,000	4	25	$ 1,258,952,366	$ 20,669,514	$ 5.55
AC-50-4-100	AC	50,000	4	100	$ 1,432,156,166	$ 20,632,314	$ 6.15
AC-50-4-250	AC	50,000	4	250	$ 1,752,928,541	$ 25,539,097	$ 7.55
AC-50-4-500	AC	50,000	4	500	$ 2,368,307,916	$ 31,531,849	$ 10.03
DC-50-4-25	DC	50,000	4	25	$ 1,475,478,204	$ 24,242,303	$ 6.51
DC-50-4-100	DC	50,000	4	100	$ 1,597,899,954	$ 26,988,686	$ 7.09
DC-50-4-250	DC	50,000	4	250	$ 1,842,743,454	$ 32,481,453	$ 8.25
DC-50-4-500	DC	50,000	4	500	$ 2,402,395,954	$ 35,279,716	$ 10.36
HG-50-4-25	Hydrogen	50,000	4	25	$ 114,920,150	$ 4,309,506	$ 0.65
HG-50-4-100	Hydrogen	50,000	4	100	$ 173,786,844	$ 5,648,072	$ 0.93
HG-50-4-250	Hydrogen	50,000	4	250	$ 248,850,332	$ 4,665,944	$ 1.13
HG-50-4-500	Hydrogen	50,000	4	500	$ 468,743,714	$ 9,374,874	$ 2.16
NG-50-4-25	Natural Gas	50,000	4	25	$ 32,395,915	$ 1,052,867	$ 0.17
NG-50-4-100	Natural Gas	50,000	4	100	$ 63,453,462	$ 1,744,970	$ 0.32
NG-50-4-250	Natural Gas	50,000	4	250	$ 160,618,455	$ 3,389,049	$ 0.75
NG-50-4-500	Natural Gas	50,000	4	500	$ 324,552,823	$ 7,302,439	$ 1.54
AC-250-4-25	AC	250,000	4	25	$ 5,838,672,986	$ 92,969,779	$ 5.12
AC-250-4-100	AC	250,000	4	100	$ 6,041,895,236	$ 111,462,240	$ 5.47
AC-250-4-250	AC	250,000	4	250	$ 6,448,339,736	$ 148,701,191	$ 6.18
AC-250-4-500	AC	250,000	4	500	$ 7,487,031,236	$ 156,621,214	$ 6.99
DC-250-4-25	DC	250,000	4	25	$ 7,089,495,734	$ 120,912,058	$ 6.31
DC-250-4-100	DC	250,000	4	100	$ 7,270,995,734	$ 128,458,156	$ 6.52
DC-250-4-250	DC	250,000	4	250	$ 7,633,995,734	$ 143,550,352	$ 6.94
DC-250-4-500	DC	250,000	4	500	$ 8,299,495,734	$ 157,034,683	$ 7.56
HG-250-4-25	Hydrogen	250,000	4	25	$ 438,298,815	$ 16,436,206	$ 0.49
HG-250-4-100	Hydrogen	250,000	4	100	$ 531,565,699	$ 17,275,885	$ 0.57
HG-250-4-250	Hydrogen	250,000	4	250	$ 727,721,512	$ 13,644,778	$ 0.66
HG-250-4-500	Hydrogen	250,000	4	500	$ 1,230,105,466	$ 24,602,109	$ 1.14
NG-250-4-25	Natural Gas	250,000	4	25	$ 95,117,900	$ 3,091,332	$ 0.10
NG-250-4-100	Natural Gas	250,000	4	100	$ 188,680,225	$ 5,188,706	$ 0.19
NG-250-4-250	Natural Gas	250,000	4	250	$ 366,890,976	$ 7,741,400	$ 0.34
NG-250-4-500	Natural Gas	250,000	4	500	$ 857,927,458	$ 19,303,368	$ 0.82
AC-500-4-25	AC	500,000	4	25	$ 10,986,454,729	$ 185,815,366	$ 4.88
AC-500-4-100	AC	500,000	4	100	$ 11,243,869,579	$ 222,427,715	$ 5.17
AC-500-4-250	AC	500,000	4	250	$ 11,758,699,279	$ 295,866,925	$ 5.77
AC-500-4-500	AC	500,000	4	500	$ 14,332,847,779	$ 312,384,378	$ 6.76
DC-500-4-25	DC	500,000	4	25	$ 13,411,970,426	$ 240,566,052	$ 6.03
DC-500-4-100	DC	500,000	4	100	$ 13,774,970,426	$ 255,658,249	$ 6.24
DC-500-4-250	DC	500,000	4	250	$ 14,375,164,076	$ 284,584,578	$ 6.62
DC-500-4-500	DC	500,000	4	500	$ 15,706,164,076	$ 311,553,238	$ 7.23
HG-500-4-25	Hydrogen	500,000	4	25	$ 874,574,582	$ 32,796,547	$ 0.49
HG-500-4-100	Hydrogen	500,000	4	100	$ 903,875,636	$ 29,375,958	$ 0.48
HG-500-4-250	Hydrogen	500,000	4	250	$ 1,162,609,957	$ 21,798,937	$ 0.53
HG-500-4-500	Hydrogen	500,000	4	500	$ 2,076,475,079	$ 41,529,502	$ 0.96
NG-500-4-25	Natural Gas	500,000	4	25	$ 144,430,161	$ 4,693,980	$ 0.08
NG-500-4-100	Natural Gas	500,000	4	100	$ 283,345,753	$ 7,792,008	$ 0.14
NG-500-4-250	Natural Gas	500,000	4	250	$ 547,844,704	$ 11,559,523	$ 0.26
NG-500-4-500	Natural Gas	500,000	4	500	$ 1,231,499,470	$ 27,708,738	$ 0.59

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Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost ($AUD)
AC-10-12-25	AC	10,000	12	25	$ 336,075,030	$ 3,184,484	$ 6.75
AC-10-12-100	AC	10,000	12	100	$ 453,533,580	$ 3,823,787	$ 8.97
AC-10-12-250	AC	10,000	12	250	$ 714,778,080	$ 5,241,883	$ 13.91
AC-10-12-500	AC	10,000	12	500	$ 1,326,658,580	$ 7,939,998	$ 25.31
DC-10-12-25	DC	10,000	12	25	$ 480,103,105	$ 4,474,236	$ 9.61
DC-10-12-100	DC	10,000	12	100	$ 562,685,605	$ 5,385,651	$ 11.31
DC-10-12-250	DC	10,000	12	250	$ 727,850,605	$ 7,208,479	$ 14.70
DC-10-12-500	DC	10,000	12	500	$ 1,157,400,605	$ 9,356,229	$ 22.77
HG-10-12-25	Hydrogen	10,000	12	25	$ 85,777,219	$ 3,216,646	$ 2.41
HG-10-12-100	Hydrogen	10,000	12	100	$ 120,066,505	$ 3,902,161	$ 3.20
HG-10-12-250	Hydrogen	10,000	12	250	$ 141,819,976	$ 2,659,125	$ 3.22
HG-10-12-500	Hydrogen	10,000	12	500	$ 253,026,827	$ 5,060,537	$ 5.84
NG-10-12-25	Natural Gas	10,000	12	25	$ 26,108,572	$ 848,529	$ 0.70
NG-10-12-100	Natural Gas	10,000	12	100	$ 45,824,903	$ 1,260,185	$ 1.16
NG-10-12-250	Natural Gas	10,000	12	250	$ 85,895,095	$ 1,812,387	$ 2.01
NG-10-12-500	Natural Gas	10,000	12	500	$ 164,937,843	$ 3,711,101	$ 3.92
AC-50-12-25	AC	50,000	12	25	$ 1,505,228,955	$ 13,146,360	$ 5.98
AC-50-12-100	AC	50,000	12	100	$ 1,678,432,755	$ 13,109,160	$ 6.58
AC-50-12-250	AC	50,000	12	250	$ 1,999,205,130	$ 18,015,943	$ 7.97
AC-50-12-500	AC	50,000	12	500	$ 2,614,584,505	$ 24,008,695	$ 10.45
DC-50-12-25	DC	50,000	12	25	$ 1,721,754,792	$ 16,719,149	$ 6.93
DC-50-12-100	DC	50,000	12	100	$ 1,844,176,542	$ 19,465,532	$ 7.52
DC-50-12-250	DC	50,000	12	250	$ 2,089,020,042	$ 24,958,299	$ 8.68
DC-50-12-500	DC	50,000	12	500	$ 2,648,672,542	$ 27,756,562	$ 10.78
HG-50-12-25	Hydrogen	50,000	12	25	$ 308,859,819	$ 11,582,243	$ 1.73
HG-50-12-100	Hydrogen	50,000	12	100	$ 349,704,322	$ 11,365,390	$ 1.86
HG-50-12-250	Hydrogen	50,000	12	250	$ 428,267,071	$ 8,030,008	$ 1.95
HG-50-12-500	Hydrogen	50,000	12	500	$ 648,182,954	$ 12,963,659	$ 2.99
NG-50-12-25	Natural Gas	50,000	12	25	$ 70,923,195	$ 2,305,004	$ 0.38
NG-50-12-100	Natural Gas	50,000	12	100	$ 106,367,701	$ 2,925,112	$ 0.54
NG-50-12-250	Natural Gas	50,000	12	250	$ 160,618,455	$ 3,389,049	$ 0.75
NG-50-12-500	Natural Gas	50,000	12	500	$ 324,552,823	$ 7,302,439	$ 1.54
AC-250-12-25	AC	250,000	12	25	$ 7,005,246,300	$ 55,354,008	$ 5.50
AC-250-12-100	AC	250,000	12	100	$ 7,208,468,550	$ 73,846,469	$ 5.85
AC-250-12-250	AC	250,000	12	250	$ 7,614,913,050	$ 111,085,420	$ 6.56
AC-250-12-500	AC	250,000	12	500	$ 8,653,604,550	$ 119,005,443	$ 7.37
DC-250-12-25	DC	250,000	12	25	$ 8,256,069,049	$ 83,296,287	$ 6.69
DC-250-12-100	DC	250,000	12	100	$ 8,437,569,049	$ 90,842,385	$ 6.90
DC-250-12-250	DC	250,000	12	250	$ 8,800,569,049	$ 105,934,581	$ 7.32
DC-250-12-500	DC	250,000	12	500	$ 9,466,069,049	$ 119,418,912	$ 7.94
HG-250-12-25	Hydrogen	250,000	12	25	$ 1,310,850,348	$ 49,156,888	$ 1.47
HG-250-12-100	Hydrogen	250,000	12	100	$ 1,414,765,995	$ 45,979,895	$ 1.51
HG-250-12-250	Hydrogen	250,000	12	250	$ 1,346,952,513	$ 25,255,360	$ 1.22
HG-250-12-500	Hydrogen	250,000	12	500	$ 1,798,079,214	$ 35,961,584	$ 1.66
NG-250-12-25	Natural Gas	250,000	12	25	$ 192,178,325	$ 6,245,796	$ 0.20
NG-250-12-100	Natural Gas	250,000	12	100	$ 283,345,753	$ 7,792,008	$ 0.29
NG-250-12-250	Natural Gas	250,000	12	250	$ 455,522,797	$ 9,611,531	$ 0.43
NG-250-12-500	Natural Gas	250,000	12	500	$ 857,927,458	$ 19,303,368	$ 0.82
AC-500-12-25	AC	500,000	12	25	$ 13,189,982,100	$ 110,583,825	$ 5.21
AC-500-12-100	AC	500,000	12	100	$ 13,447,396,950	$ 147,196,173	$ 5.51
AC-500-12-250	AC	500,000	12	250	$ 13,962,226,650	$ 220,635,383	$ 6.11
AC-500-12-500	AC	500,000	12	500	$ 16,536,375,150	$ 237,152,836	$ 7.10
DC-500-12-25	DC	500,000	12	25	$ 15,615,497,798	$ 165,334,511	$ 6.37
DC-500-12-100	DC	500,000	12	100	$ 15,978,497,798	$ 180,426,707	$ 6.58
DC-500-12-250	DC	500,000	12	250	$ 16,578,691,448	$ 209,353,036	$ 6.95
DC-500-12-500	DC	500,000	12	500	$ 17,909,691,448	$ 236,321,696	$ 7.57
HG-500-12-25	Hydrogen	500,000	12	25	$ 2,619,677,649	$ 98,237,912	$ 1.47
HG-500-12-100	Hydrogen	500,000	12	100	$ 2,698,933,128	$ 87,715,327	$ 1.44
HG-500-12-250	Hydrogen	500,000	12	250	$ 2,681,475,823	$ 50,277,672	$ 1.22
HG-500-12-500	Hydrogen	500,000	12	500	$ 3,026,530,821	$ 60,530,616	$ 1.40
NG-500-12-25	Natural Gas	500,000	12	25	$ 383,294,929	$ 12,457,085	$ 0.20
NG-500-12-100	Natural Gas	500,000	12	100	$ 472,311,872	$ 12,988,576	$ 0.24
NG-500-12-250	Natural Gas	500,000	12	250	$ 665,313,549	$ 14,038,116	$ 0.31
NG-500-12-500	Natural Gas	500,000	12	500	$ 1,231,499,470	$ 27,708,738	$ 0.59

Document Title	Document No. (Client / GPA)	Rev / Status
Cost Estimate - Brief Results	- 210739-REP-001	Issued for Information

Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost ($AUD)
AC-10-24-25	AC	10,000	24	25	$ 422,186,210	$ 3,774,763	$ 8.41
AC-10-24-100	AC	10,000	24	100	$ 539,644,760	$ 4,414,065	$ 10.63
AC-10-24-250	AC	10,000	24	250	$ 800,889,260	$ 5,832,162	$ 15.57
AC-10-24-500	AC	10,000	24	500	$ 1,412,769,760	$ 8,530,276	$ 26.97
DC-10-24-25	DC	10,000	24	25	$ 566,214,285	$ 5,064,515	$ 11.28
DC-10-24-100	DC	10,000	24	100	$ 648,796,785	$ 5,975,929	$ 12.97
DC-10-24-250	DC	10,000	24	250	$ 813,961,785	$ 7,798,757	$ 16.36
DC-10-24-500	DC	10,000	24	500	$ 1,243,511,785	$ 9,946,507	$ 24.43
HG-10-24-25	Hydrogen	10,000	24	25	$ 129,296,273	$ 4,848,610	$ 3.63
HG-10-24-100	Hydrogen	10,000	24	100	$ 173,786,844	$ 5,648,072	$ 4.63
HG-10-24-250	Hydrogen	10,000	24	250	$ 195,815,907	$ 3,671,548	$ 4.45
HG-10-24-500	Hydrogen	10,000	24	500	$ 253,026,827	$ 5,060,537	$ 5.84
NG-10-24-25	Natural Gas	10,000	24	25	$ 38,907,769	$ 1,264,502	$ 1.04
NG-10-24-100	Natural Gas	10,000	24	100	$ 63,453,462	$ 1,744,970	$ 1.60
NG-10-24-250	Natural Gas	10,000	24	250	$ 85,895,095	$ 1,812,387	$ 2.01
NG-10-24-500	Natural Gas	10,000	24	500	$ 164,937,843	$ 3,711,101	$ 3.92
AC-50-24-25	AC	50,000	24	25	$ 1,914,257,060	$ 16,097,751	$ 7.57
AC-50-24-100	AC	50,000	24	100	$ 2,087,460,860	$ 16,060,551	$ 8.17
AC-50-24-250	AC	50,000	24	250	$ 2,408,233,235	$ 20,967,334	$ 9.56
AC-50-24-500	AC	50,000	24	500	$ 3,023,612,610	$ 26,960,086	$ 12.04
DC-50-24-25	DC	50,000	24	25	$ 2,130,782,897	$ 19,670,540	$ 8.52
DC-50-24-100	DC	50,000	24	100	$ 2,253,204,647	$ 22,416,923	$ 9.11
DC-50-24-250	DC	50,000	24	250	$ 2,498,048,147	$ 27,909,690	$ 10.27
DC-50-24-500	DC	50,000	24	500	$ 3,057,700,647	$ 30,707,953	$ 12.37
HG-50-24-25	Hydrogen	50,000	24	25	$ 656,436,698	$ 24,616,376	$ 3.69
HG-50-24-100	Hydrogen	50,000	24	100	$ 612,922,272	$ 19,919,974	$ 3.27
HG-50-24-250	Hydrogen	50,000	24	250	$ 658,074,936	$ 12,338,905	$ 2.99
HG-50-24-500	Hydrogen	50,000	24	500	$ 837,328,482	$ 16,746,570	$ 3.86
NG-50-24-25	Natural Gas	50,000	24	25	$ 105,516,039	$ 3,429,271	$ 0.56
NG-50-24-100	Natural Gas	50,000	24	100	$ 153,150,789	$ 4,211,647	$ 0.77
NG-50-24-250	Natural Gas	50,000	24	250	$ 209,568,778	$ 4,421,901	$ 0.98
NG-50-24-500	Natural Gas	50,000	24	500	$ 388,413,408	$ 8,739,302	$ 1.85
AC-250-24-25	AC	250,000	24	25	$ 8,942,747,850	$ 70,110,964	$ 7.01
AC-250-24-100	AC	250,000	24	100	$ 9,145,970,100	$ 88,603,426	$ 7.36
AC-250-24-250	AC	250,000	24	250	$ 9,552,414,600	$ 125,842,376	$ 8.07
AC-250-24-500	AC	250,000	24	500	$ 10,591,106,100	$ 133,762,399	$ 8.88
DC-250-24-25	DC	250,000	24	25	$ 10,193,570,599	$ 98,053,243	$ 8.20
DC-250-24-100	DC	250,000	24	100	$ 10,375,070,599	$ 105,599,341	$ 8.41
DC-250-24-250	DC	250,000	24	250	$ 10,738,070,599	$ 120,691,538	$ 8.84
DC-250-24-500	DC	250,000	24	500	$ 11,403,570,599	$ 134,175,868	$ 9.45
HG-250-24-25	Hydrogen	250,000	24	25	$ 2,619,677,649	$ 98,237,912	$ 2.94
HG-250-24-100	Hydrogen	250,000	24	100	$ 2,698,933,128	$ 87,715,327	$ 2.88
HG-250-24-250	Hydrogen	250,000	24	250	$ 2,681,475,823	$ 50,277,672	$ 2.44
HG-250-24-500	Hydrogen	250,000	24	500	$ 2,810,932,218	$ 56,218,644	$ 2.59
NG-250-24-25	Natural Gas	250,000	24	25	$ 383,294,929	$ 12,457,085	$ 0.41
NG-250-24-100	Natural Gas	250,000	24	100	$ 472,311,872	$ 12,988,576	$ 0.48
NG-250-24-250	Natural Gas	250,000	24	250	$ 547,844,704	$ 11,559,523	$ 0.51
NG-250-24-500	Natural Gas	250,000	24	500	$ 1,049,360,922	$ 23,610,621	$ 1.00
AC-500-24-25	AC	500,000	24	25	$ 16,849,707,250	$ 140,097,737	$ 6.65
AC-500-24-100	AC	500,000	24	100	$ 17,107,122,100	$ 176,710,086	$ 6.95
AC-500-24-250	AC	500,000	24	250	$ 17,621,951,800	$ 250,149,296	$ 7.55
AC-500-24-500	AC	500,000	24	500	$ 20,196,100,300	$ 266,666,749	$ 8.54
DC-500-24-25	DC	500,000	24	25	$ 19,275,222,948	$ 194,848,423	$ 7.81
DC-500-24-100	DC	500,000	24	100	$ 19,638,222,948	$ 209,940,619	$ 8.02
DC-500-24-250	DC	500,000	24	250	$ 20,238,416,598	$ 238,866,948	$ 8.39
DC-500-24-500	DC	500,000	24	500	$ 21,569,416,598	$ 265,835,609	$ 9.01
HG-500-24-25	Hydrogen	500,000	24	25	$ 4,975,954,622	$ 186,598,298	$ 2.79
HG-500-24-100	Hydrogen	500,000	24	100	$ 5,333,052,760	$ 173,324,215	$ 2.84
HG-500-24-250	Hydrogen	500,000	24	250	$ 5,084,973,239	$ 95,343,248	$ 2.31
HG-500-24-500	Hydrogen	500,000	24	500	$ 5,596,094,187	$ 111,921,884	$ 2.58
NG-500-24-25	Natural Gas	500,000	24	25	$ 765,528,135	$ 24,879,664	$ 0.41
NG-500-24-100	Natural Gas	500,000	24	100	$ 781,483,828	$ 21,490,805	$ 0.39
NG-500-24-250	Natural Gas	500,000	24	250	$ 909,755,552	$ 19,195,842	$ 0.43
NG-500-24-500	Natural Gas	500,000	24	500	$ 1,507,129,505	$ 33,910,414	$ 0.72

APPENDIX 3B LEVELISED COST OF STORAGE RESULTS TABLE

Document Title	Document No. (Client / GPA)	Rev / Status
Cost Estimate - Brief Results	- 210739-REP-001	Issued for Information

Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost Storage ($AUD/GJ/d)
AC-10-0-25	AC	10,000	0	25	$ -	$ -	$ -
AC-10-0-100	AC	10,000	0	100	$ -	$ -	$ -
AC-10-0-250	AC	10,000	0	250	$ -	$ -	$ -
AC-10-0-500	AC	10,000	0	500	$ -	$ -	$ -
DC-10-0-25	DC	10,000	0	25	$ -	$ -	$ -
DC-10-0-100	DC	10,000	0	100	$ -	$ -	$ -
DC-10-0-250	DC	10,000	0	250	$ -	$ -	$ -
DC-10-0-500	DC	10,000	0	500	$ -	$ -	$ -
HG-10-0-25	Hydrogen	10,000	0	25	$ -	$ -	$ -
HG-10-0-100	Hydrogen	10,000	0	100	$ -	$ -	$ -
HG-10-0-250	Hydrogen	10,000	0	250	$ -	$ -	$ -
HG-10-0-500	Hydrogen	10,000	0	500	$ -	$ -	$ -
NG-10-0-25	Natural Gas	10,000	0	25	$ -	$ -	$ -
NG-10-0-100	Natural Gas	10,000	0	100	$ -	$ -	$ -
NG-10-0-250	Natural Gas	10,000	0	250	$ -	$ -	$ -
NG-10-0-500	Natural Gas	10,000	0	500	$ -	$ -	$ -
AC-50-0-25	AC	50,000	0	25	$ -	$ -	$ -
AC-50-0-100	AC	50,000	0	100	$ -	$ -	$ -
AC-50-0-250	AC	50,000	0	250	$ -	$ -	$ -
AC-50-0-500	AC	50,000	0	500	$ -	$ -	$ -
DC-50-0-25	DC	50,000	0	25	$ -	$ -	$ -
DC-50-0-100	DC	50,000	0	100	$ -	$ -	$ -
DC-50-0-250	DC	50,000	0	250	$ -	$ -	$ -
DC-50-0-500	DC	50,000	0	500	$ -	$ -	$ -
HG-50-0-25	Hydrogen	50,000	0	25	$ -	$ -	$ -
HG-50-0-100	Hydrogen	50,000	0	100	$ -	$ -	$ -
HG-50-0-250	Hydrogen	50,000	0	250	$ -	$ -	$ -
HG-50-0-500	Hydrogen	50,000	0	500	$ -	$ -	$ -
NG-50-0-25	Natural Gas	50,000	0	25	$ -	$ -	$ -
NG-50-0-100	Natural Gas	50,000	0	100	$ -	$ -	$ -
NG-50-0-250	Natural Gas	50,000	0	250	$ -	$ -	$ -
NG-50-0-500	Natural Gas	50,000	0	500	$ -	$ -	$ -
AC-250-0-25	AC	250,000	0	25	$ -	$ -	$ -
AC-250-0-100	AC	250,000	0	100	$ -	$ -	$ -
AC-250-0-250	AC	250,000	0	250	$ -	$ -	$ -
AC-250-0-500	AC	250,000	0	500	$ -	$ -	$ -
DC-250-0-25	DC	250,000	0	25	$ -	$ -	$ -
DC-250-0-100	DC	250,000	0	100	$ -	$ -	$ -
DC-250-0-250	DC	250,000	0	250	$ -	$ -	$ -
DC-250-0-500	DC	250,000	0	500	$ -	$ -	$ -
HG-250-0-25	Hydrogen	250,000	0	25	$ -	$ -	$ -
HG-250-0-100	Hydrogen	250,000	0	100	$ -	$ -	$ -
HG-250-0-250	Hydrogen	250,000	0	250	$ -	$ -	$ -
HG-250-0-500	Hydrogen	250,000	0	500	$ -	$ -	$ -
NG-250-0-25	Natural Gas	250,000	0	25	$ -	$ -	$ -
NG-250-0-100	Natural Gas	250,000	0	100	$ -	$ -	$ -
NG-250-0-250	Natural Gas	250,000	0	250	$ -	$ -	$ -
NG-250-0-500	Natural Gas	250,000	0	500	$ -	$ -	$ -
AC-500-0-25	AC	500,000	0	25	$ -	$ -	$ -
AC-500-0-100	AC	500,000	0	100	$ -	$ -	$ -
AC-500-0-250	AC	500,000	0	250	$ -	$ -	$ -
AC-500-0-500	AC	500,000	0	500	$ -	$ -	$ -
DC-500-0-25	DC	500,000	0	25	$ -	$ -	$ -
DC-500-0-100	DC	500,000	0	100	$ -	$ -	$ -
DC-500-0-250	DC	500,000	0	250	$ -	$ -	$ -
DC-500-0-500	DC	500,000	0	500	$ -	$ -	$ -
HG-500-0-25	Hydrogen	500,000	0	25	$ -	$ -	$ -
HG-500-0-100	Hydrogen	500,000	0	100	$ -	$ -	$ -
HG-500-0-250	Hydrogen	500,000	0	250	$ -	$ -	$ -
HG-500-0-500	Hydrogen	500,000	0	500	$ -	$ -	$ -
NG-500-0-25	Natural Gas	500,000	0	25	$ -	$ -	$ -
NG-500-0-100	Natural Gas	500,000	0	100	$ -	$ -	$ -
NG-500-0-250	Natural Gas	500,000	0	250	$ -	$ -	$ -
NG-500-0-500	Natural Gas	500,000	0	500	$ -	$ -	$ -

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Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost Storage ($AUD/GJ/d)
AC-10-4-25	AC	10,000	4	25	$ 256,485,877	$ 3,472,225	$ 29.23
AC-10-4-100	AC	10,000	4	100	$ 256,485,877	$ 3,472,225	$ 29.23
AC-10-4-250	AC	10,000	4	250	$ 256,485,877	$ 3,472,225	$ 29.23
AC-10-4-500	AC	10,000	4	500	$ 256,485,877	$ 3,472,225	$ 29.23
DC-10-4-25	DC	10,000	4	25	$ 256,485,877	$ 3,472,225	$ 29.23
DC-10-4-100	DC	10,000	4	100	$ 256,485,877	$ 3,472,225	$ 29.23
DC-10-4-250	DC	10,000	4	250	$ 256,485,877	$ 3,472,225	$ 29.23
DC-10-4-500	DC	10,000	4	500	$ 256,485,877	$ 3,472,225	$ 29.23
HG-10-4-25	Hydrogen	10,000	4	25	$ 26,233,770	$ 983,766	$ 4.07
HG-10-4-100	Hydrogen	10,000	4	100	$ 22,059,105	$ 716,921	$ 3.23
HG-10-4-250	Hydrogen	10,000	4	250	$ -	$ -	$ (0.00)
HG-10-4-500	Hydrogen	10,000	4	500	$ 51,757,766	$ 1,035,155	$ 6.47
NG-10-4-25	Natural Gas	10,000	4	25	$ 5,044,094	$ 163,933	$ 0.74
NG-10-4-100	Natural Gas	10,000	4	100	$ 690,505	$ 18,989	$ 0.10
NG-10-4-250	Natural Gas	10,000	4	250	$ -	$ -	$ (0.00)
NG-10-4-500	Natural Gas	10,000	4	500	$ -	$ -	$ (0.00)
AC-50-4-25	AC	50,000	4	25	$ 1,218,307,916	$ 17,361,125	$ 28.07
AC-50-4-100	AC	50,000	4	100	$ 1,218,307,916	$ 17,361,125	$ 28.07
AC-50-4-250	AC	50,000	4	250	$ 1,218,307,916	$ 17,361,125	$ 28.07
AC-50-4-500	AC	50,000	4	500	$ 1,218,307,916	$ 17,361,125	$ 28.07
DC-50-4-25	DC	50,000	4	25	$ 1,218,307,916	$ 17,361,125	$ 28.07
DC-50-4-100	DC	50,000	4	100	$ 1,218,307,916	$ 17,361,125	$ 28.07
DC-50-4-250	DC	50,000	4	250	$ 1,218,307,916	$ 17,361,125	$ 28.07
DC-50-4-500	DC	50,000	4	500	$ 1,218,307,916	$ 17,361,125	$ 28.07
HG-50-4-25	Hydrogen	50,000	4	25	$ 93,515,400	$ 3,506,828	$ 2.90
HG-50-4-100	Hydrogen	50,000	4	100	$ 84,447,863	$ 2,744,556	$ 2.47
HG-50-4-250	Hydrogen	50,000	4	250	$ 53,034,426	$ 994,395	$ 1.30
HG-50-4-500	Hydrogen	50,000	4	500	$ -	$ -	$ 0.00
NG-50-4-25	Natural Gas	50,000	4	25	$ 17,640,311	$ 573,310	$ 0.52
NG-50-4-100	Natural Gas	50,000	4	100	$ -	$ -	$ 0.00
NG-50-4-250	Natural Gas	50,000	4	250	$ -	$ -	$ 0.00
NG-50-4-500	Natural Gas	50,000	4	500	$ -	$ -	$ 0.00
AC-250-4-25	AC	250,000	4	25	$ 5,770,932,236	$ 86,805,625	$ 26.90
AC-250-4-100	AC	250,000	4	100	$ 5,770,932,236	$ 86,805,625	$ 26.90
AC-250-4-250	AC	250,000	4	250	$ 5,770,932,236	$ 86,805,625	$ 26.90
AC-250-4-500	AC	250,000	4	500	$ 5,770,932,236	$ 86,805,625	$ 26.90
DC-250-4-25	DC	250,000	4	25	$ 5,770,932,236	$ 86,805,625	$ 26.90
DC-250-4-100	DC	250,000	4	100	$ 5,770,932,236	$ 86,805,625	$ 26.90
DC-250-4-250	DC	250,000	4	250	$ 5,770,932,236	$ 86,805,625	$ 26.90
DC-250-4-500	DC	250,000	4	500	$ 5,770,932,236	$ 86,805,625	$ 26.90
HG-250-4-25	Hydrogen	250,000	4	25	$ 395,210,980	$ 14,820,412	$ 2.45
HG-250-4-100	Hydrogen	250,000	4	100	$ 323,937,027	$ 10,527,953	$ 1.90
HG-250-4-250	Hydrogen	250,000	4	250	$ 225,945,878	$ 4,236,485	$ 1.11
HG-250-4-500	Hydrogen	250,000	4	500	$ -	$ -	$ -
NG-250-4-25	Natural Gas	250,000	4	25	$ 62,721,984	$ 2,038,464	$ 0.37
NG-250-4-100	Natural Gas	250,000	4	100	$ 54,816,052	$ 1,507,441	$ 0.30
NG-250-4-250	Natural Gas	250,000	4	250	$ -	$ -	$ -
NG-250-4-500	Natural Gas	250,000	4	500	$ -	$ -	$ -
AC-500-4-25	AC	500,000	4	25	$ 10,900,649,779	$ 173,611,250	$ 25.74
AC-500-4-100	AC	500,000	4	100	$ 10,900,649,779	$ 173,611,250	$ 25.74
AC-500-4-250	AC	500,000	4	250	$ 10,900,649,779	$ 173,611,250	$ 25.74
AC-500-4-500	AC	500,000	4	500	$ 10,900,649,779	$ 173,611,250	$ 25.74
DC-500-4-25	DC	500,000	4	25	$ 10,900,649,779	$ 173,611,250	$ 25.74
DC-500-4-100	DC	500,000	4	100	$ 10,900,649,779	$ 173,611,250	$ 25.74
DC-500-4-250	DC	500,000	4	250	$ 10,900,649,779	$ 173,611,250	$ 25.74
DC-500-4-500	DC	500,000	4	500	$ 10,900,649,779	$ 173,611,250	$ 25.74
HG-500-4-25	Hydrogen	500,000	4	25	$ 806,961,638	$ 30,261,061	$ 2.50
HG-500-4-100	Hydrogen	500,000	4	100	$ 612,247,310	$ 19,898,038	$ 1.79
HG-500-4-250	Hydrogen	500,000	4	250	$ 434,888,445	$ 8,154,158	$ 1.07
HG-500-4-500	Hydrogen	500,000	4	500	$ 278,395,865	$ 5,567,917	$ 0.70
NG-500-4-25	Natural Gas	500,000	4	25	$ 97,182,251	$ 3,158,423	$ 0.28
NG-500-4-100	Natural Gas	500,000	4	100	$ 66,585,131	$ 1,831,091	$ 0.18
NG-500-4-250	Natural Gas	500,000	4	250	$ 11,504,021	$ 242,735	$ 0.03
NG-500-4-500	Natural Gas	500,000	4	500	$ -	$ -	$ -

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Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost Storage ($AUD/GJ/d)
AC-10-12-25	AC	10,000	12	25	$ 308,333,580	$ 1,967,594	$ 10.45
AC-10-12-100	AC	10,000	12	100	$ 308,333,580	$ 1,967,594	$ 10.45
AC-10-12-250	AC	10,000	12	250	$ 308,333,580	$ 1,967,594	$ 10.45
AC-10-12-500	AC	10,000	12	500	$ 308,333,580	$ 1,967,594	$ 10.45
DC-10-12-25	DC	10,000	12	25	$ 308,333,580	$ 1,967,594	$ 10.45
DC-10-12-100	DC	10,000	12	100	$ 308,333,580	$ 1,967,594	$ 10.45
DC-10-12-250	DC	10,000	12	250	$ 308,333,580	$ 1,967,594	$ 10.45
DC-10-12-500	DC	10,000	12	500	$ 308,333,580	$ 1,967,594	$ 10.45
HG-10-12-25	Hydrogen	10,000	12	25	$ 75,034,574	$ 2,813,797	$ 3.88
HG-10-12-100	Hydrogen	10,000	12	100	$ 72,638,445	$ 2,360,749	$ 3.55
HG-10-12-250	Hydrogen	10,000	12	250	$ 46,046,949	$ 863,380	$ 1.89
HG-10-12-500	Hydrogen	10,000	12	500	$ 51,757,766	$ 1,035,155	$ 2.16
NG-10-12-25	Natural Gas	10,000	12	25	$ 16,397,062	$ 532,905	$ 0.80
NG-10-12-100	Natural Gas	10,000	12	100	$ 15,915,576	$ 437,678	$ 0.73
NG-10-12-250	Natural Gas	10,000	12	250	$ -	$ -	$ (0.00)
NG-10-12-500	Natural Gas	10,000	12	500	$ -	$ -	$ (0.00)
AC-50-12-25	AC	50,000	12	25	$ 1,464,584,505	$ 9,837,971	$ 9.99
AC-50-12-100	AC	50,000	12	100	$ 1,464,584,505	$ 9,837,971	$ 9.99
AC-50-12-250	AC	50,000	12	250	$ 1,464,584,505	$ 9,837,971	$ 9.99
AC-50-12-500	AC	50,000	12	500	$ 1,464,584,505	$ 9,837,971	$ 9.99
DC-50-12-25	DC	50,000	12	25	$ 1,571,413,698	$ 9,837,971	$ 9.99
DC-50-12-100	DC	50,000	12	100	$ 1,571,413,698	$ 9,837,971	$ 9.99
DC-50-12-250	DC	50,000	12	250	$ 1,571,413,698	$ 9,837,971	$ 9.99
DC-50-12-500	DC	50,000	12	500	$ 1,571,413,698	$ 9,837,971	$ 9.99
HG-50-12-25	Hydrogen	50,000	12	25	$ 287,455,068	$ 10,779,565	$ 2.97
HG-50-12-100	Hydrogen	50,000	12	100	$ 260,365,341	$ 8,461,874	$ 2.54
HG-50-12-250	Hydrogen	50,000	12	250	$ 232,451,164	$ 4,358,459	$ 1.90
HG-50-12-500	Hydrogen	50,000	12	500	$ 179,439,239	$ 3,588,785	$ 1.50
NG-50-12-25	Natural Gas	50,000	12	25	$ 56,167,591	$ 1,825,447	$ 0.55
NG-50-12-100	Natural Gas	50,000	12	100	$ 42,914,239	$ 1,180,142	$ 0.39
NG-50-12-250	Natural Gas	50,000	12	250	$ -	$ -	$ (0.00)
NG-50-12-500	Natural Gas	50,000	12	500	$ -	$ -	$ (0.00)
AC-250-12-25	AC	250,000	12	25	$ 6,937,505,550	$ 49,189,854	$ 9.52
AC-250-12-100	AC	250,000	12	100	$ 6,937,505,550	$ 49,189,854	$ 9.52
AC-250-12-250	AC	250,000	12	250	$ 6,937,505,550	$ 49,189,854	$ 9.52
AC-250-12-500	AC	250,000	12	500	$ 6,937,505,550	$ 49,189,854	$ 9.52
DC-250-12-25	DC	250,000	12	25	$ 7,471,651,516	$ 49,189,854	$ 9.52
DC-250-12-100	DC	250,000	12	100	$ 7,471,651,516	$ 49,189,854	$ 9.52
DC-250-12-250	DC	250,000	12	250	$ 7,471,651,516	$ 49,189,854	$ 9.52
DC-250-12-500	DC	250,000	12	500	$ 7,471,651,516	$ 49,189,854	$ 9.52
HG-250-12-25	Hydrogen	250,000	12	25	$ 1,267,762,514	$ 47,541,094	$ 2.62
HG-250-12-100	Hydrogen	250,000	12	100	$ 1,207,137,323	$ 39,231,963	$ 2.36
HG-250-12-250	Hydrogen	250,000	12	250	$ 845,176,880	$ 15,847,066	$ 1.38
HG-250-12-500	Hydrogen	250,000	12	500	$ 567,973,749	$ 11,359,475	$ 0.95
NG-250-12-25	Natural Gas	250,000	12	25	$ 159,782,410	$ 5,192,928	$ 0.31
NG-250-12-100	Natural Gas	250,000	12	100	$ 149,481,580	$ 4,110,743	$ 0.27
NG-250-12-250	Natural Gas	250,000	12	250	$ 88,631,821	$ 1,870,131	$ 0.15
NG-250-12-500	Natural Gas	250,000	12	500	$ -	$ -	$ (0.00)
AC-500-12-25	AC	500,000	12	25	$ 13,104,177,150	$ 98,379,708	$ 9.05
AC-500-12-100	AC	500,000	12	100	$ 13,104,177,150	$ 98,379,708	$ 9.05
AC-500-12-250	AC	500,000	12	250	$ 13,104,177,150	$ 98,379,708	$ 9.05
AC-500-12-500	AC	500,000	12	500	$ 13,104,177,150	$ 98,379,708	$ 9.05
DC-500-12-25	DC	500,000	12	25	$ 14,172,469,082	$ 98,379,708	$ 9.05
DC-500-12-100	DC	500,000	12	100	$ 14,172,469,082	$ 98,379,708	$ 9.05
DC-500-12-250	DC	500,000	12	250	$ 14,172,469,082	$ 98,379,708	$ 9.05
DC-500-12-500	DC	500,000	12	500	$ 14,172,469,082	$ 98,379,708	$ 9.05
HG-500-12-25	Hydrogen	500,000	12	25	$ 2,552,064,705	$ 95,702,426	$ 2.64
HG-500-12-100	Hydrogen	500,000	12	100	$ 2,407,304,803	$ 78,237,406	$ 2.35
HG-500-12-250	Hydrogen	500,000	12	250	$ 1,953,754,311	$ 36,632,893	$ 1.60
HG-500-12-500	Hydrogen	500,000	12	500	$ 1,228,451,606	$ 24,569,032	$ 1.02
NG-500-12-25	Natural Gas	500,000	12	25	$ 336,047,018	$ 10,921,528	$ 0.33
NG-500-12-100	Natural Gas	500,000	12	100	$ 255,551,251	$ 7,027,659	$ 0.23
NG-500-12-250	Natural Gas	500,000	12	250	$ 128,972,866	$ 2,721,327	$ 0.11
NG-500-12-500	Natural Gas	500,000	12	500	$ -	$ -	$ (0.00)

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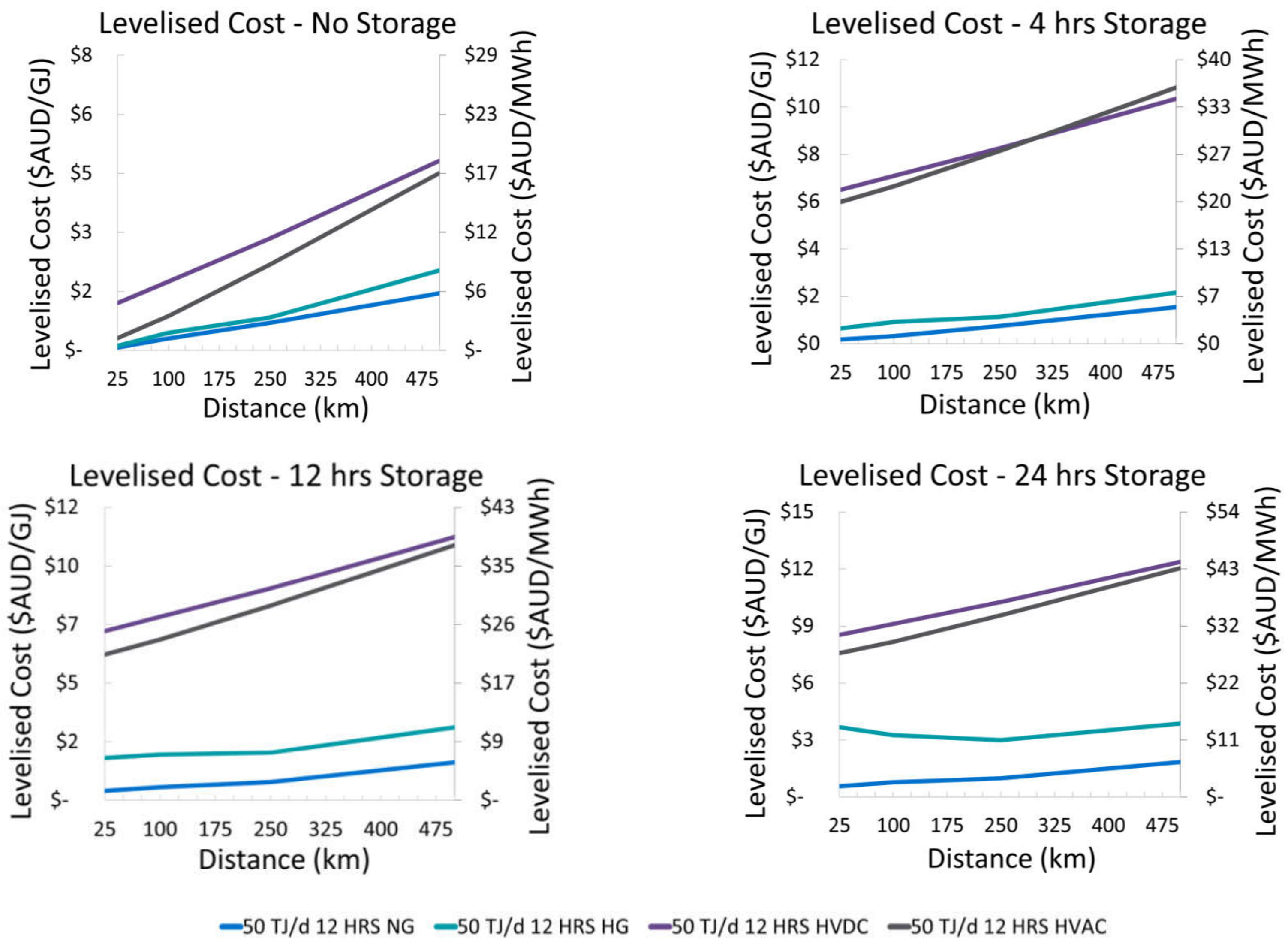
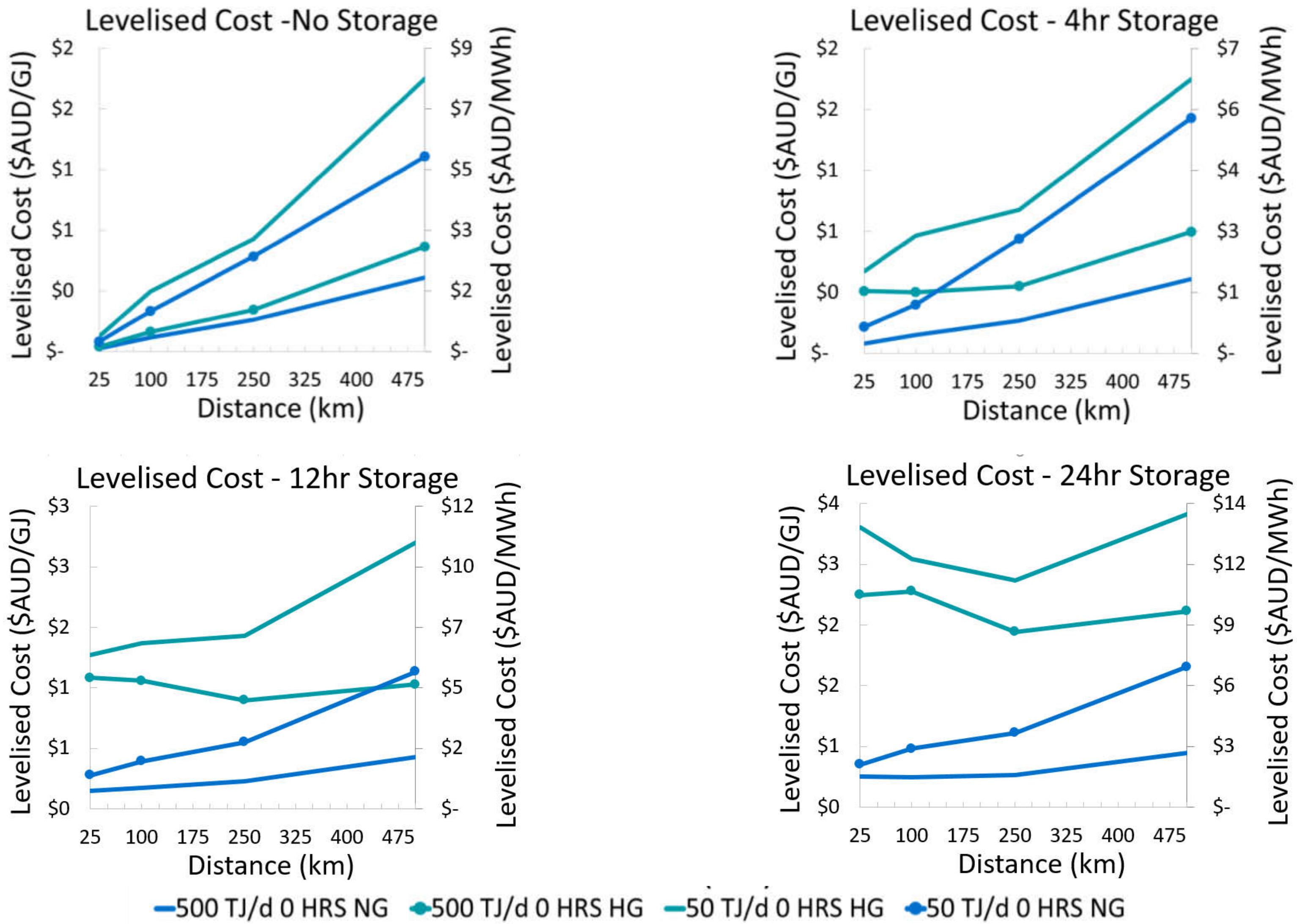
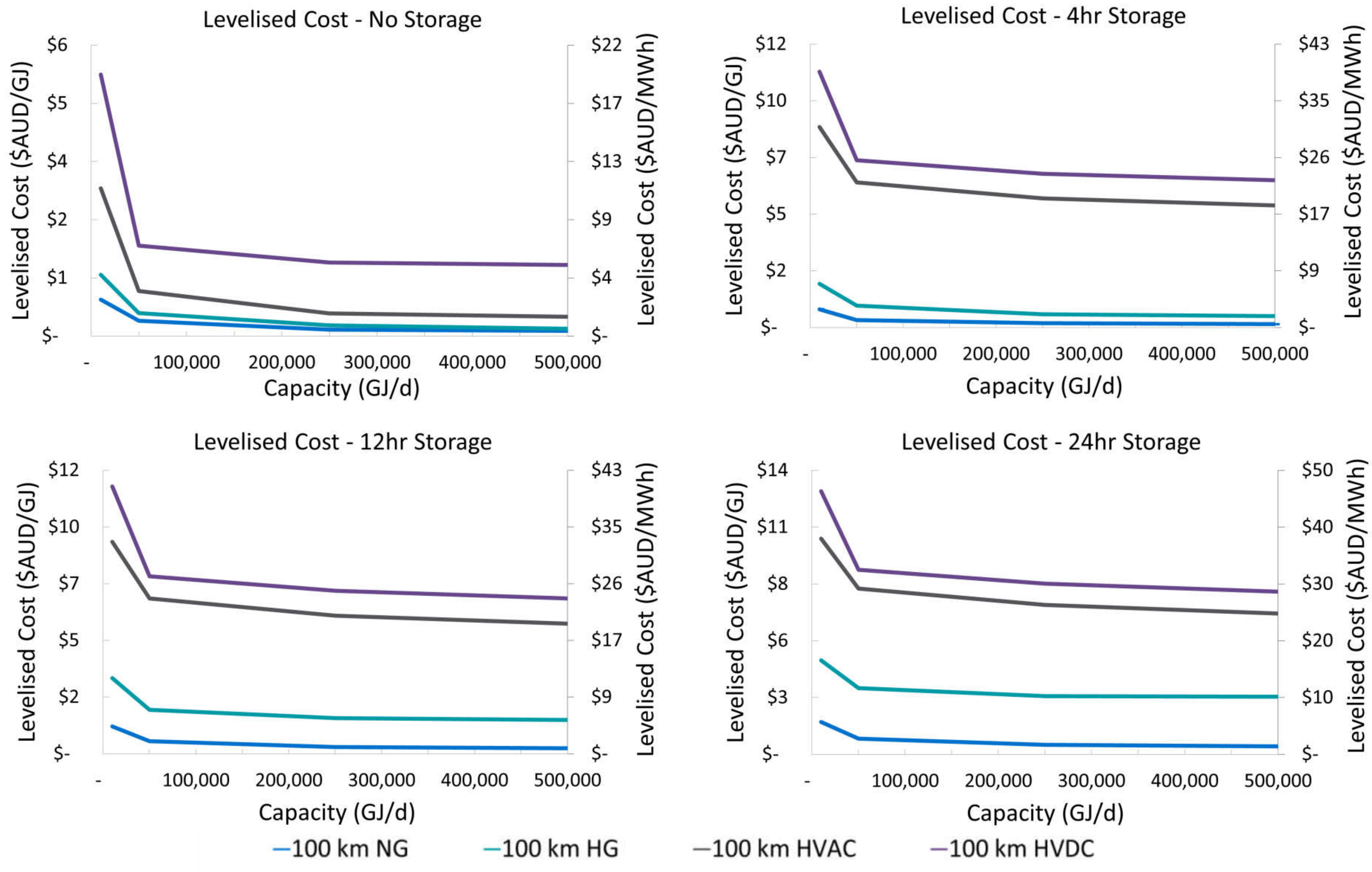
Document Title	Document No. (Client / GPA)	Rev / Status
Cost Estimate - Brief Results	- 210739-REP-001	Issued for Information

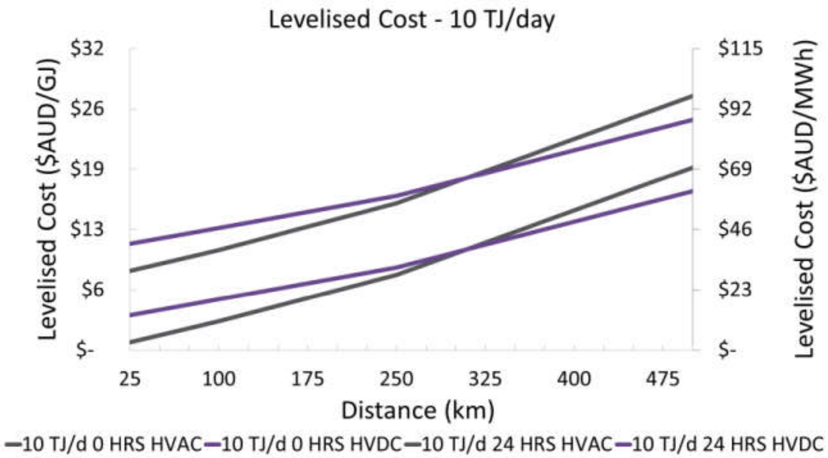
Case	Transmission Type	Energy Value (GJ/d)	Storage (Hours)	Transmission Length (km)	CAPEX ($AUD)	Annual OPEX - Year 0 ($AUD)	Levelised Cost Storage ($AUD/GJ/d)
AC-10-24-25	AC	10,000	24	25	$ 394,444,760	$ 2,557,872	$ 6.70
AC-10-24-100	AC	10,000	24	100	$ 394,444,760	$ 2,557,872	$ 6.70
AC-10-24-250	AC	10,000	24	250	$ 394,444,760	$ 2,557,872	$ 6.70
AC-10-24-500	AC	10,000	24	500	$ 394,444,760	$ 2,557,872	$ 6.70
DC-10-24-25	DC	10,000	24	25	$ 394,444,760	$ 2,557,872	$ 6.70
DC-10-24-100	DC	10,000	24	100	$ 394,444,760	$ 2,557,872	$ 6.70
DC-10-24-250	DC	10,000	24	250	$ 394,444,760	$ 2,557,872	$ 6.70
DC-10-24-500	DC	10,000	24	500	$ 394,444,760	$ 2,557,872	$ 6.70
HG-10-24-25	Hydrogen	10,000	24	25	$ 118,553,629	$ 4,445,761	$ 3.06
HG-10-24-100	Hydrogen	10,000	24	100	$ 126,358,785	$ 4,106,661	$ 3.08
HG-10-24-250	Hydrogen	10,000	24	250	$ 100,042,880	$ 1,875,804	$ 2.05
HG-10-24-500	Hydrogen	10,000	24	500	$ 51,757,766	$ 1,035,155	$ 1.08
NG-10-24-25	Natural Gas	10,000	24	25	$ 29,196,259	$ 948,878	$ 0.71
NG-10-24-100	Natural Gas	10,000	24	100	$ 33,544,135	$ 922,464	$ 0.77
NG-10-24-250	Natural Gas	10,000	24	250	$ -	$ -	$ (0.00)
NG-10-24-500	Natural Gas	10,000	24	500	$ -	$ -	$ (0.00)
AC-50-24-25	AC	50,000	24	25	$ 1,873,612,610	$ 12,789,362	$ 6.40
AC-50-24-100	AC	50,000	24	100	$ 1,873,612,610	$ 12,789,362	$ 6.40
AC-50-24-250	AC	50,000	24	250	$ 1,873,612,610	$ 12,789,362	$ 6.40
AC-50-24-500	AC	50,000	24	500	$ 1,873,612,610	$ 12,789,362	$ 6.40
DC-50-24-25	DC	50,000	24	25	$ 2,012,490,561	$ 12,789,362	$ 6.40
DC-50-24-100	DC	50,000	24	100	$ 2,012,490,561	$ 12,789,362	$ 6.40
DC-50-24-250	DC	50,000	24	250	$ 2,012,490,561	$ 12,789,362	$ 6.40
DC-50-24-500	DC	50,000	24	500	$ 2,012,490,561	$ 12,789,362	$ 6.40
HG-50-24-25	Hydrogen	50,000	24	25	$ 635,031,948	$ 23,813,698	$ 3.28
HG-50-24-100	Hydrogen	50,000	24	100	$ 523,583,291	$ 17,016,457	$ 2.56
HG-50-24-250	Hydrogen	50,000	24	250	$ 462,259,029	$ 8,667,357	$ 1.89
HG-50-24-500	Hydrogen	50,000	24	500	$ 368,584,768	$ 7,371,695	$ 1.54
NG-50-24-25	Natural Gas	50,000	24	25	$ 90,760,435	$ 2,949,714	$ 0.44
NG-50-24-100	Natural Gas	50,000	24	100	$ 89,697,327	$ 2,466,677	$ 0.41
NG-50-24-250	Natural Gas	50,000	24	250	$ 48,950,323	$ 1,032,852	$ 0.21
NG-50-24-500	Natural Gas	50,000	24	500	$ 63,860,585	$ 1,436,863	$ 0.28
AC-250-24-25	AC	250,000	24	25	$ 8,875,007,100	$ 63,946,810	$ 6.10
AC-250-24-100	AC	250,000	24	100	$ 8,875,007,100	$ 63,946,810	$ 6.10
AC-250-24-250	AC	250,000	24	250	$ 8,875,007,100	$ 63,946,810	$ 6.10
AC-250-24-500	AC	250,000	24	500	$ 8,875,007,100	$ 63,946,810	$ 6.10
DC-250-24-25	DC	250,000	24	25	$ 9,569,396,856	$ 63,946,810	$ 6.10
DC-250-24-100	DC	250,000	24	100	$ 9,569,396,856	$ 63,946,810	$ 6.10
DC-250-24-250	DC	250,000	24	250	$ 9,569,396,856	$ 63,946,810	$ 6.10
DC-250-24-500	DC	250,000	24	500	$ 9,569,396,856	$ 63,946,810	$ 6.10
HG-250-24-25	Hydrogen	250,000	24	25	$ 2,576,589,815	$ 96,622,118	$ 2.66
HG-250-24-100	Hydrogen	250,000	24	100	$ 2,491,304,456	$ 80,967,395	$ 2.43
HG-250-24-250	Hydrogen	250,000	24	250	$ 2,179,700,189	$ 40,869,379	$ 1.79
HG-250-24-500	Hydrogen	250,000	24	500	$ 1,580,826,753	$ 31,616,535	$ 1.32
NG-250-24-25	Natural Gas	250,000	24	25	$ 350,899,013	$ 11,404,218	$ 0.34
NG-250-24-100	Natural Gas	250,000	24	100	$ 338,447,699	$ 9,307,312	$ 0.31
NG-250-24-250	Natural Gas	250,000	24	250	$ 180,953,728	$ 3,818,124	$ 0.15
NG-250-24-500	Natural Gas	250,000	24	500	$ 191,433,465	$ 4,307,253	$ 0.17
AC-500-24-25	AC	500,000	24	25	$ 16,763,902,300	$ 127,893,621	$ 5.80
AC-500-24-100	AC	500,000	24	100	$ 16,763,902,300	$ 127,893,621	$ 5.80
AC-500-24-250	AC	500,000	24	250	$ 16,763,902,300	$ 127,893,621	$ 5.80
AC-500-24-500	AC	500,000	24	500	$ 16,763,902,300	$ 127,893,621	$ 5.80
DC-500-24-25	DC	500,000	24	25	$ 18,152,681,812	$ 127,893,621	$ 5.80
DC-500-24-100	DC	500,000	24	100	$ 18,152,681,812	$ 127,893,621	$ 5.80
DC-500-24-250	DC	500,000	24	250	$ 18,152,681,812	$ 127,893,621	$ 5.80
DC-500-24-500	DC	500,000	24	500	$ 18,152,681,812	$ 127,893,621	$ 5.80
HG-500-24-25	Hydrogen	500,000	24	25	$ 4,908,341,679	$ 184,062,813	$ 2.54
HG-500-24-100	Hydrogen	500,000	24	100	$ 5,041,424,435	$ 163,846,294	$ 2.46
HG-500-24-250	Hydrogen	500,000	24	250	$ 4,357,251,726	$ 81,698,470	$ 1.78
HG-500-24-500	Hydrogen	500,000	24	500	$ 3,798,014,972	$ 75,960,299	$ 1.58
NG-500-24-25	Natural Gas	500,000	24	25	$ 718,280,224	$ 23,344,107	$ 0.35
NG-500-24-100	Natural Gas	500,000	24	100	$ 564,723,207	$ 15,529,888	$ 0.26
NG-500-24-250	Natural Gas	500,000	24	250	$ 373,414,869	$ 7,879,054	$ 0.16
NG-500-24-500	Natural Gas	500,000	24	500	$ 275,630,035	$ 6,201,676	$ 0.12

APPENDIX 3C PIPELINES VS WIRES COMPARISON

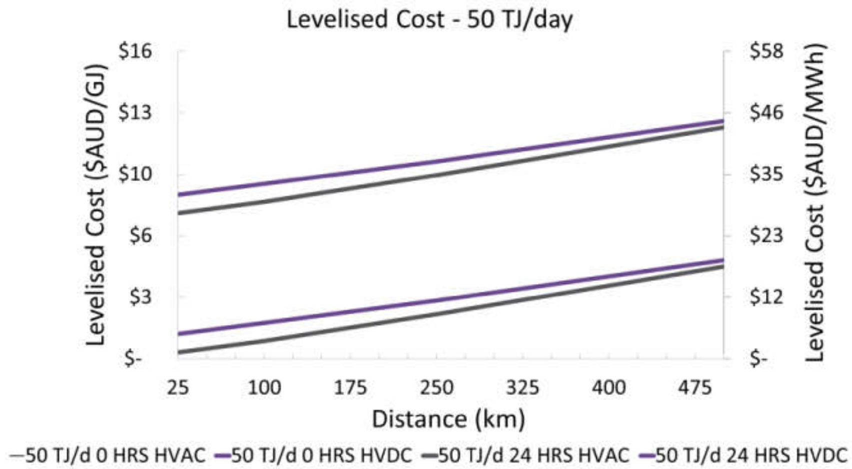



Levelised Cost -No Storage
Levelised Cost ($AUD/GJ)
$2
$2
$1
$1
$0
$-
Levelised Cost ($AUD/MWh)
$9
$7
$5
$3
$2
$-
25 100 175 250 325 400 475
Distance (km)
Levelised Cost - 4hr Storage
Levelised Cost ($AUD/GJ)
$2
$2
$1
$1
$0
$-
Levelised Cost ($AUD/MWh)
$7
$6
$4
$3
$1
$-
25 100 175 250 325 400 475
Distance (km)
Levelised Cost - 12hr Storage
Levelised Cost ($AUD/GJ)
$3
$3
$2
$1
$1
$0
Levelised Cost ($AUD/MWh)
$12
$10
$7
$5
$2
$-
25 100 175 250 325 400 475
Distance (km)
Levelised Cost - 24hr Storage
Levelised Cost ($AUD/GJ)
$4
$3
$2
$2
$1
$0
Levelised Cost ($AUD/MWh)
$14
$12
$9
$6
$3
$-
25 100 175 250 325 400 475
Distance (km)
500 TJ/d 0 HRS NG
500 TJ/d 0 HRS HG
50 TJ/d 0 HRS HG
50 TJ/d 0 HRS NG

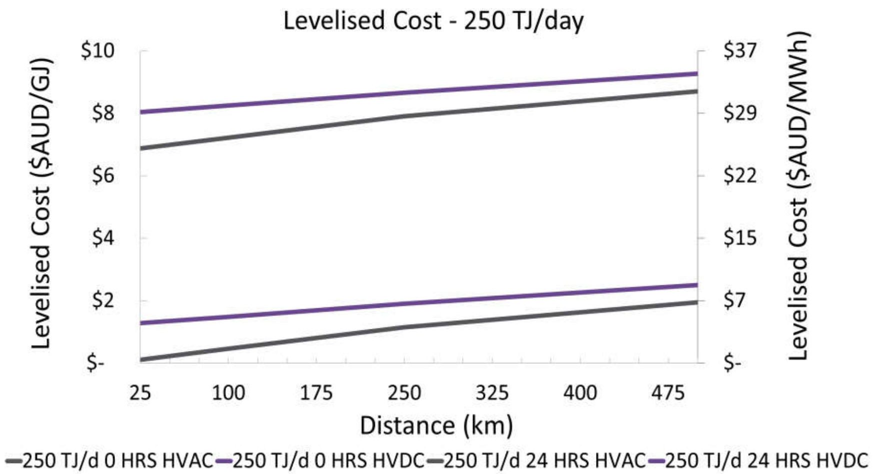

Levelised Cost - No Storage
Levelised Cost ($AUD/GJ)
$6
$5
$4
$2
$1
$-
Levelised Cost ($AUD/MWh)
$22
$17
$13
$9
$4
$-
Capacity (GJ/d)
-
100,000
200,000
300,000
400,000
500,000
Levelised Cost - 4hr Storage
$12
$10
$7
$5
$2
$-
$43
$35
$26
$17
$9
$-
Levelised Cost - 12hr Storage
$12
$10
$7
$5
$2
$-
$43
$35
$26
$17
$9
$-
Levelised Cost - 24hr Storage
$14
$11
$8
$6
$3
$-
$50
$40
$30
$20
$10
$-
100 km NG
100 km HG
100 km HVAC
100 km HVDC



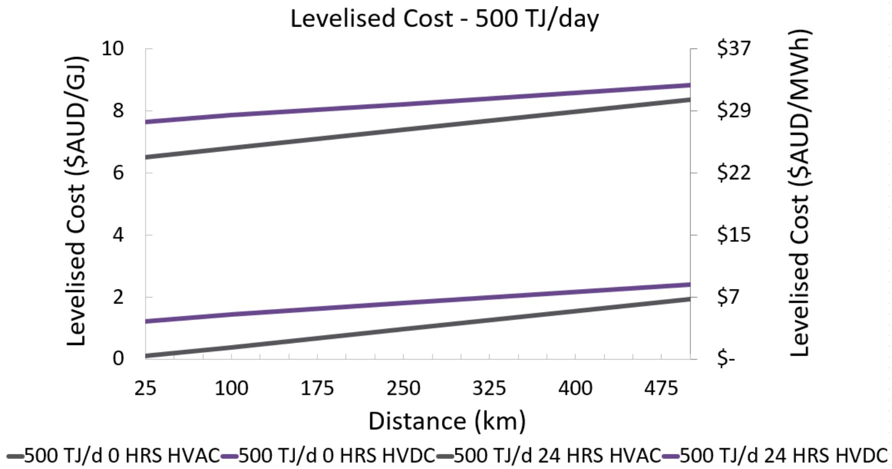
Levelised Cost - 10 TJ/day
Levelised Cost ($AUD/GJ)
$32
$26
$19
$13
$6
$-
Levelised Cost ($AUD/MWh)
$115
$92
$69
$46
$23
$-
25
100
175
250
325
400
475
Distance (km)
10 TJ/d 0 HRS HVAC
10 TJ/d 0 HRS HVDC
10 TJ/d 24 HRS HVAC
10 TJ/d 24 HRS HVDC



Levelised Cost - 50 TJ/day
Levelised Cost ($AUD/GJ)
$16
$13
$10
$6
$3
$-
Levelised Cost ($AUD/MWh)
$58
$46
$35
$23
$12
$-
25
100
175
250
325
400
475
Distance (km)
50 TJ/d 0 HRS HVAC
50 TJ/d 0 HRS HVDC
50 TJ/d 24 HRS HVAC
50 TJ/d 24 HRS HVDC



Levelised Cost - 250 TJ/day
Levelised Cost ($AUD/GJ)
$10
$8
$6
$4
$2
$-
Levelised Cost ($AUD/MWh)
$37
$29
$22
$15
$7
$-
25
100
175
250
325
400
475
Distance (km)
250 TJ/d 0 HRS HVAC
250 TJ/d 0 HRS HVDC
250 TJ/d 24 HRS HVAC
250 TJ/d 24 HRS HVDC



Levelised Cost - 500 TJ/day
Levelised Cost ($AUD/GJ)
10
8
6
4
2
0
Levelised Cost ($AUD/MWh)
$37
$29
$22
$15
$7
$-
25
100
175
250
325
400
475
Distance (km)
500 TJ/d 0 HRS HVAC
500 TJ/d 0 HRS HVDC
500 TJ/d 24 HRS HVAC
500 TJ/d 24 HRS HVDC

APPENDIX 4 ELECTRICAL TRANSMISSION LINE SIZING AND COST ESTIMATION

As per Appendix 1 both HVAC and HVDC transmission lines were considered for all length scenarios 25km, 100km, 250km and 500km and capacity scenarios 10TJ/day, 50TJ/day, 250 TJ and 500 TJ/d.

The required daily energy throughput for each case (TJ/d) has been converted to a continuous transmission line rating (loadability) in MW as per the following:

Table 8: Energy Throughput (TJ/day) and Required Line Rating (MW)

Energy Throughput (TJ /day)	Required Transmission Line Rating (MW)
10	116
50	579
259	2,894
500	5,787

It should be noted that the above assumption of a continuous fixed load always equal to the transmission line rating is a simplification. In practice the load on a transmission line varies with demand and the transmission line rating must accommodate the required peak load which is always greater than the average load.

Based on the required transmission line length and required transmission line rating, high level specification and equipment selection was undertaken to determine an indicative transmission line solution for each case.

Based on the two technology options, four length options and four throughput options a total of thirty two unique solutions were determined. The parameters specified for each solution include:

1. Line operating voltage and for HVDC the line configuration (monopole or bipole)
2. Line conductor size and number of conductors per phase
3. Number of circuits
4. Line power loss

Based on the indicative line solution for each case a cost estimate and financial assessment was completed including:

1. Initial CAPEX of the transmission line and for HVDC the converter stations
2. Initial OPEX of the transmission line and for HVDC the converter stations
3. Annual cost of electrical losses
4. Net present cost (NPC)
5. Levelised cost of energy throughput

APPENDIX 4A COMPARISON OF HVAC AND HVDC TECHNOLOGIES

Both HVAC and HVDC technologies are mature and deployed in Australia and around the world.

Some of the key points of differences between HVAC and HVDC are outlined below:

1. In Australia HVAC transmission lines operate up to voltages of 500kV with some lines overseas reaching voltages in excess of 1,000kV.
2. HVDC transmission lines in Australia operate at 400kV with some future projects planned to operate up to 600kV.
3. HVDC is typically favoured for point-to-point power transfer over longer distances (> 500km) where there are no intermediate loads. Use of multi-terminal HVDC systems is possible, however not yet commonplace.
4. HVAC typically has higher electrical losses compared with an equivalent HVDC line. It should be noted HVDC converter stations do have losses which can be significant for HVDC VSC systems.
5. To use a HVDC transmission line the electricity must first be converted from HVAC. Once transmitted via the HVDC transmission line the electricity is converted back to HVAC. A converter station is required at each of the HVDC line to facilitate this conversion. The cost of this converter station is significant.
6. The cost per km to construct a HVDC line is less than the cost of an equivalent HVAC transmission line. This facilitates a ‘break-even’ distance which is the line distance at which the high cost of the HVDC converter stations is overcome by the lower incremental cost of the transmission line. This break-even distance is typically greater than 500km.

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APPENDIX 4B HVAC TRANSMISSION LINE SIZING

There are a significant number of technical and economic factors which must be considered to produce an optimised HVAC transmission line design for a specific installation scenario. Typically, the design is refined over several iterations as additional design, engineering studies and other information becomes available. There are also economic trade-offs for example increasing the conductor size which increases CAPEX but lowers lifetime power losses or providing line compensation vs. increasing the line voltage level.

For the purposes of The Study an indicative HVAC overhead line solution has been selected based on the following technical constraints:

1. The thermal limit of the overhead line conductors.
2. A voltage drop in the line of no more than five per cent.
3. The steady-state stability limit.
4. A power loss in the line of no more than five per cent.

The following table summarises the line solution for each case.

Table 9: Indicative HVAC OHL solution

Case	Required Load (MW)	Length (km)	Voltage (kV)	Conductor type / number per phase	Number of Circuits
AC-10-0-25	116	25	132	LIME / 1	1 (SCST)
AC-50-0-25	579	25	275	LIME / 2	1 (SCST)
AC-250-0-25	2,894	25	500	PAW PAW / 4	1 (SCST)
AC-500-0-25	5,787	25	500	PAW PAW / 4	2 (DCST)
AC-10-0-100	116	100	132	MANGO / 3	1 (SCST)
AC-50-0-100	579	100	330	PAW PAW / 4	1 (SCST)
AC-250-0-100	2,894	100	500	PAW PAW / 4	1 (SCST)
AC-500-0-100	5,787	100	500	PAW PAW / 4	2 (DCST)
AC-10-0-250	116	250	275	LIME / 2	1 (SCST)
AC-50-0-250	579	250	330	PAW PAW / 4	1 (SCST)
AC-250-0-250	2,894	250	500	PAW PAW / 4	1 (SCST)
AC-500-0-250	5,787	250	500	PAW PAW / 4	2 (DCST)
AC-10-0-500	116	500	330	PAW PAW / 2	1 (SCST)
AC-50-0-500	579	500	500	ORANGE / 3	1 (SCST)
AC-250-0-500	2,894	500	500	PAW PAW / 4	2 (DCST)
AC-500-0-500	5,787	500	500	PAW PAW /4	4 (2 x DCST)

In addition to the technical constrains outlined above the following provides an overview of some further key constraints and assumptions:

1. The maximum AC voltage has been limited to 500kV for The Study. Currently no transmission line within Australia operates at voltages higher than 500kV. Higher voltages do have the potential to reduce costs for some cases by reducing the number of circuits required, reducing the line conductor size and/or the electrical losses. Any reduction in costs would need to be weighed against the technical risk, regulatory requirements and costs involved with introducing a new voltage level into Australia.
2. The HVAC transmission line selected has a maximum loadability (rating) equal to the required energy throughput of each case. In practice a transmission line would be designed for a certain load factor with a maximum loadability higher than its average energy throughput.
3. Conductors are assumed to be ACSR with a maximum of four conductors per phase. Conductor sizes are those typically used in Australia with parameters from reputable manufacturers.
4. For longer line lengths (250km and 500km) capacitive compensation has been considered to improve line loadability.

GPA

APPENDIX 4C HVAC TRASMISSION LINE COSTS

The total transmission line costs have been determined over the nominal 20-year project life. The total project costs include:

1. Line capital expenditure costs – the total upfront cost to instal the line
2. Line operation and maintenance costs – annual cost to operate and maintain the line
3. Line annual energy loss – economic cost of electrical losses in the line

HVAC Transmission Line CAPEX

Capital costs have been determined from a number of sources including:

1. The 2021 AEMO Transmission Cost Database[26]
2. The MISO Cost Estimation Guide for MTP21[27]
3. WECC Capital Costs for Transmission and Substations[28]
4. Previous project pricing and experience.

Where applicable extrapolation has been used to determine costs based on similar installations. For CAPEX estimation a preference has been given to Australian sources vs. international sources.

The following provides the total installed cost per km for each of the indicative line solutions.

Table 10: HVAC transmission line CAPEX costs

Voltage	Length (km)	Voltage (kV)	Circuits	Total Installed Cost ($M/km)
AC-10-0-25	25	132	1 (SCST)	$1.11
AC-50-0-25	25	275	1 (SCST)	$1.63
AC-250-0-25	25	500	1 (SCST)	$2.71
AC-500-0-25	25	500	2 (DCST)	$3.43
AC-10-0-100	100	132	1 (SCST)	$1.45
AC-50-0-100	100	330	1 (SCST)	$2.14
AC-250-0-100	100	500	1 (SCST)	$2.71
AC-500-0-100	100	500	2 (DCST)	$3.43
AC-10-0-250	250	275	1 (SCST)	$1.63
AC-50-0-250	250	330	1 (SCST)	$2.14
AC-250-0-250	250	500	1 (SCST)	$3.12*
AC-500-0-250	250	500	2 (DCST)	$3.78*
AC-10-0-500	500	330	1 (SCST)	$2.04

[26] AEMO, 2021, *Transmission costs for the 2022 Integrated System Plan*, https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan
[27] MISO, 2021, *Transmission Cost Estimation Guide For MTEP21*, https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/psc-cost-estimation-guide-for-mtep21-20210209/
[28] WECC, 2019, *Transmission Cost Calculator*, https://www.wecc.org/Administrative/

AC-50-0-500	500	500	1 (SCST)	$2.30
AC-250-0-500	500	500	2 (DCST)	$3.95*
AC-500-0-500	500	500	4 (2 x DCST)	$7.55*

***Includes allowance for capacitive compensation**

The following provides an overview of some key assumptions for CAPEX estimation:

1. Consummate with the required accuracy of The Study CAPEX costs have estimated to rough order of magnitude equivalent to AACE class 5 (+/- 50%).
2. Only the transmission line capital costs have been considered. The AC substation costs at each end of the line have been excluded from The Study. This is to ensure a direct comparison with the natural gas and hydrogen gas cases is possible.
3. Cost basis is 2021 Australian dollars. Foreign currencies have been converted to Australian dollars where applicable.
4. Line total installed cost includes:
    a. All materials, plant and equipment.
    b. Easement and offset costs.
    c. Civil, structural, mechanical and electrical installation works.
    d. Design, testing and commissioning costs.
    e. Indirect project costs.
    f. Fifteen per cent risk and contingency factor.
5. Transmission lines are assumed installed on flat ground in rural areas.

HVAC Transmission Line OPEX

Annual expenditure is required to provide ongoing operations and maintenance for a transmission line. Based on typical figures for shorter and longer transmission lines the following table provides the assumed annual OPEX cost as a percentage of the initial CAPEX.

Table 11: HVAC transmission Line OPEX costs

Transmission Line Length	OPEX (% of initial CAPEX per year)
25km	0.5%
100km	0.5%
250km	0.25%
500km	0.25%

HVAC Transmission Line Electrical Losses

A transmission line will lose a certain percentage of its transmitted energy as heat dissipated in the overhead line conductors. These losses have an economic value which should be accounted for in the analysis of total life of asset costs.

Table 12: HVAC transmission line losses

Voltage	Length (km)	Voltage (kV)	Circuits	Power loss (%)
AC-10-0-25	25	132	1 (SCST)	2.1%
AC-50-0-25	25	275	1 (SCST)	1.2%
AC-250-0-25	25	500	1 (SCST)	0.5%
AC-500-0-25	25	500	2 (DCST)	0.5%
AC-10-0-100	100	132	1 (SCST)	2.2%
AC-50-0-100	100	330	1 (SCST)	0.9%
AC-250-0-100	100	500	1 (SCST)	1.9%
AC-500-0-100	100	500	2 (DCST)	1.9%
AC-10-0-250	250	275	1 (SCST)	2.5%
AC-50-0-250	250	330	1 (SCST)	2.2%
AC-250-0-250	250	500	1 (SCST)	4.7%
AC-500-0-250	250	500	2 (DCST)	4.7%
AC-10-0-500	500	330	1 (SCST)	1.7%
AC-50-0-500	500	500	1 (SCST)	3.3%
AC-250-0-500	500	500	2 (DCST)	4.7%
AC-500-0-500	500	500	4 (2 x DCST)	4.7%

APPENDIX 4D HVDC TRANSMISSION LINE SIZING

Typically, a HVDC system will include a long transmission line (or underground cable) with a converter station at each end of the line. While not considered in the Study multi-terminal HVDC systems are also becoming more common. A number of options exist for a HVDC transmission systems including the system topology and the technology used within the converter stations.

Common system topologies include monopole (either with or without a metallic return) and bipole (either with or without a metallic return). Monopole has only one conductor operating at rating voltage and uses either the earth as a return path or has a second conductor installed as the return path. Bipole systems have two conductors at rated voltage and opposite polarity. In some instances, a bipole system may also have a third conductor installed and used as a metallic return path.

Technology used within the converter stations is either voltage-sourced converters (VSC) or line-commutated converters (LCC). The preferred technology is application specific with VSC technology becoming more widespread over recent years. The Study has nominally selected LCC technology, however it is not envisaged VSC technology would materially impact results for a high-level study of this nature.

For each energy throughput and HVDC line length scenarios an indicative HVDC overhead line solution has been selected based on the following technical constraints:

1. Maximum voltage of +/-600kV
2. A monopole or bipole topology
3. A power loss in the line of no more than five per cent.

The following table summarises the line solution for each case.

Table 13: Indicative HVDC OHL solution

Case	Required Load (MW)	Length (km)	Voltage (kV)	Topology	Number of Circuits
DC-10-0-25	116	25	320	Monopole	1
DC-50-0-25	579	25	500	Monopole	1
DC-250-0-25	2,894	25	600	Bipole	1
DC-500-0-25	5,787	25	600	Bipole	2
DC-10-0-100	116	100	320	Monopole	1
DC-50-0-100	579	100	500	Monopole	1
DC-250-0-100	2,894	100	600	Bipole	1
DC-500-0-100	5,787	100	600	Bipole	2
DC-10-0-250	116	250	320	Monopole	1
DC-50-0-250	579	250	500	Monopole	1
DC-250-0-250	2,894	250	600	Bipole	1
DC-500-0-250	5,787	250	600	Bipole	2
DC-10-0-500	116	500	320	Monopole	1
DC-50-0-500	579	500	500	Monopole	1
DC-250-0-500	2,894	500	600	Bipole	1
DC-500-0-500	5,787	500	600	Bipole	2

In addition to the technical constrains outlined above the following provides an overview of some further key assumptions:

1. The maximum DC voltage has been limited to 600kV for the Study. This is based on the voltage level of proposed future projects in Australia.
2. Conductors are assumed to be ACSR with a maximum of four conductors per phase. Conductor sizes are those typically used in Australia with parameters from reputable manufacturers.
3. All HVDC cases have nominally assumed LCC technology.

APPENDIX 4E HVDC TRANSMISSION LINE CAPEX

Capital costs for HVDC lines have been determined from a number of sources including:

1. The AMEO Transmission Cost Database[29]
2. The MISO Cost Estimation Guide[30]
3. WECC Capital Costs for Transmission and Substations[31]
4. GPA previous project pricing.

It should be noted no HVDC project has been completed in Australia since Basslink in 2006 so current costs in an Australian context are based on estimated costs for future projects or on extrapolation from international projects. For CAPEX estimation a preference has been given to Australian estimated costs vs. international sources. The following provides the total installed cost per km for each of the solutions.

Table 14: HVDC Transmission Line CAPEX Costs

Voltage	Length (km)	Voltage (kV)	Circuits	Total Installed Cost ($M/km)	Converter Station Cost ($M)
DC-10-0-25	25	132	1	$ 1.10	$ 72
DC-50-0-25	25	275	1	$ 1.63	$ 108
DC-250-0-25	25	500	1	$ 2.42	$ 629
DC-500-0-25	25	500	2	$ 2.42	$ 1,195
DC-10-0-100	100	132	1	$ 1.10	$ 72
DC-50-0-100	100	330	1	$ 1.63	$ 108
DC-250-0-100	100	500	1	$ 2.42	$ 629
DC-500-0-100	100	500	2	$ 2.42	$ 1,195
DC-10-0-250	250	275	1	$ 1.10	$ 72
DC-50-0-250	250	330	1	$ 1.63	$ 108
DC-250-0-250	250	500	1	$ 2.42	$ 629
DC-500-0-250	250	500	2	$ 2.42	$ 1,132
DC-10-0-500	500	330	1	$ 1.41	$ 72
DC-50-0-500	500	500	1	$ 1.94	$ 108
DC-250-0-500	500	500	1	$ 2.54	$ 629
DC-500-0-500	500	500	2	$ 2.54	$ 1,132

The following provides an overview of some key assumptions for CAPEX estimation:

[29] AEMO, 2021, *Transmission costs for the 2022 Integrated System Plan*, https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan
[30] MISO, 2021, *Transmission Cost Estimation Guide For MTEP21*, https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/psc-cost-estimation-guide-for-mtep21-20210209/
[31] WECC, 2019, *Transmission Cost Calculator*, https://www.wecc.org/Administrative/

1. Commensurate with the required accuracy of the Study CAPEX costs have been estimated to a rough order of magnitude equivalent to AACE class 5 (+/- 50%).
2. Only the transmission line capital costs and the HVDC converter station costs have been considered. The AC substation costs have been excluded from the Study.
3. Cost basis is 2021 Australian dollars. Foreign currencies have been converted to Australian dollars where applicable.
4. Line total installed cost includes:
    a. All materials, plant and equipment.
    b. Easement and offset costs.
    c. Civil, structural, mechanical and electrical installation works.
    d. Design, testing and commissioning costs.
    e. Indirect project costs.
    f. Fifteen per cent risk and contingency factor.
5. Transmission lines are assumed installed on flat ground in rural areas.

HVDC Transmission Line and Converter Station OPEX

Annual expenditure is required to provide ongoing operations and maintenance for a transmission line. The following table provides the assumed annual OPEX cost as a percentage of the initial CAPEX.

Table 15: HVDC Transmission Line OPEX Costs

Transmission Line Length	OPEX (% of initial line CAPEX per year)
25km	0.5%
100km	0.5%
250km	0.25%
500km	0.25%

In addition to the transmission line OPEX each HVDC converter station has a required annual OPEX. A figure of one per cent per annum of the initial converter station

HVDC Transmission Line Electrical Losses

A transmission line will lose a certain percentage of its transmitted energy as heat dissipated in the overhead line conductors. HVDC also incurs losses at the converter stations when converting between HVAC and HVDC. These losses have an economic value which should be accounted for in the analysis of total life of asset costs.

Table 16: HVAC Transmission Line Losses

Voltage	Length (km)	Voltage (kV)	Circuits	Power loss (%)*
DC-10-0-25	25	132	1	1.83%
DC-50-0-25	25	275	1	1.78%
DC-250-0-25	25	500	1	1.69%
DC-500-0-25	25	500	2	1.69%
DC-10-0-100	100	132	1	2.81%
DC-50-0-100	100	330	1	2.62%
DC-250-0-100	100	500	1	2.25%
DC-500-0-100	100	500	2	2.25%
DC-10-0-250	250	275	1	4.78%
DC-50-0-250	250	330	1	4.31%
DC-250-0-250	250	500	1	3.37%
DC-500-0-250	250	500	2	3.37%
DC-10-0-500	500	330	1	4.78%
DC-50-0-500	500	500	1	4.31%
DC-250-0-500	500	500	1	4.30%
DC-500-0-500	500	500	2	4.30%

*Includes 0.75 per cent of the load for each converter station.

GPA

APPENDIX 4F BESS AND PHES TECHNOLOGY SELECTION

Battery Energy Storage Systems (BESS) and Pumped Hydro Energy Storage Systems (PHES) have been considered for the HVDC and HVAC cases with 4, 12 and 24 hours of energy storage. For cases with 4 hours of storage BESS has been selected as the most suitable technology with PHES selected as the most suitable technology where 12 and 24 hours of storage is required.

The required energy storage (TJ) has been converted to an energy storage value in MWh as per the following table:

Table 17: Energy storage in TJ and MWh

Energy Throughput Case (TJ /day)	Storage Duration (hours)	Storage Rating (TJ)	Storage Rating (MWh)	Technology
10	4	1.67	463	BESS
50	4	8.33	1,389	BESS
250	4	41.67	2,778	BESS
500	4	83.33	2,315	BESS
10	12	5	6,944	PHES
50	12	25	13,889	PHES
250	12	125	11,574	PHES
500	12	250	34,722	PHES
10	24	10	69,445	PHES
50	24	50	23,148	PHES
250	24	250	69,445	PHES
500	24	500	138,889	PHES

Based on the above technology and storage requirements typical industry unit metrics have been used to determine a cost estimate and to undertake financial assessment including:

1. Initial total installed CAPEX of the storage installation.
2. Annual OPEX of the storage installation.
3. Net present cost (NPC).
4. Levelised cost of energy throughput.

BESS and PHES Installation CAPEX

Unit metrics used to derive total CAPEX have been determined from a number of sources including:

1. The CSIRO/AEMO 2020-2021 GenCost Report[32]
2. The Entura Pumped Hydro Cost Modelling completed on behalf of AMEO[33]

[32] CSIRO, 2020, *GenCost 2020-21*, https://publications.csiro.au/rpr/pub?list=BRO&pid=csiro:EP208181&expert=false&sb=RECENT&n=10&rpp=2
[33] Entura, 2018, *Pumped Hydro Cost Modelling*, *https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf*

3. EIA Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies[34]
4. The US DOE HydroWires Energy Storage Technology and Cost Characterization Report[35]
5. The IRENA Electricity Storage and Renewables: Cost and Markets to 2030[36]
6. GPA previous project pricing and studies.

Where applicable extrapolation has been used to determine costs based on similar installations. For CAPEX estimation a preference has been given to Australian sources vs international sources.

For BESS projects care should be taken when considering the high throughput cases where the storage capacity required is very large. No project has yet been undertaken anywhere near this scale and so costs should be considered only an approximate guide based on likely cost efficiency improvements over smaller projects. Similarly pumped hydro project costs vary significantly between projects and few have been completed in Australia in recent decades so costs should be considered as a comparative guide only.

The following provides the total installed cost per km for each of the indicative line solutions.

Table 18: BESS and PHES CAPEX

Case	Storage Technology	Storage Capacity (MWh)	Storage Cost ($/MWh)
AC/DC-10-4-XX	BESS	463	$480,700
AC/DC-10-12-XX	PHES	1,389	$222,000
AC/DC-10-24-XX	PHES	2,778	$142,000
AC/DC-50-4-XX	BESS	2,315	$456,665
AC/DC-50-12-XX	PHES	6,944	$210,900
AC/DC-50-24-XX	PHES	13,889	$134,900
AC/DC-250-4-XX	BESS	11,574	$432,630
AC/DC-250-12-XX	PHES	34,722	$199,800
AC/DC-250-24-XX	PHES	69,445	$127,800
AC/DC-500-4-XX	BESS	23,148	$408,595
AC/DC-500-12-XX	PHES	69,445	$188,700
AC/DC-500-24-XX	PHES	138,889	$120,700

The following provides an overview of some key assumptions for CAPEX estimation:

1. Commensurate with the required accuracy of the Study CAPEX costs have been estimated based on unit metrics to a rough order of magnitude equivalent to AACE class 5 (+/- 50%).
2. Cost basis is 2021 Australian dollars. Foreign currencies have been converted to Australian dollars where applicable.
3. The total installed cost includes:
    a. All materials, plant and equipment.
    b. Land costs.

[34] EIA, 2020, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, https://www.eia.gov/analysis/studies/powerplants/capitalcost/
[35] US DOE HydroWires, 2019, *Energy Storage Technology and Cost Characterization Report*, https://www.energy.gov/eere/water/hydrowires-publications
[36] IRENA, 2017, Electricity Storage and Renewables: Cost and Markets to 2030 https://www.irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets

c. Civil, structural, mechanical and electrical installation works.
d. Design, testing and commissioning costs.
e. Indirect project costs.
f. 1Ten per cent risk and contingency factor.

BESS and PHES Installation OPEX

Annual expenditure is required to provide ongoing operations and maintenance for storage facilities. The following table provides the assumed annual OPEX cost as a unit rate per year.

Table 19: BESS and PHES OPEX costs

Technology	OPEX
BESS	$7.5 / kWh / yr
PHES	$17 / kW / yr

For the purposes of the Study losses associated with the storage installation have not been included in the total life costs of the installation. These losses to a large degree are situation and usage case specific so it had been elected to not include them in this analysis. Including these losses would act to increase the levelised cost of the BESS or PHES installation.

APPENDIX 5 PIPELINE TECHNICAL AND DESIGN CONSIDERATIONS

GPA

APPENDIX 5A APPLICATION OF STANDARDS

AS 2885 Series

AS 2885 is the regulated Standard across Australia for high pressure natural gas transmission pipelines and for some pipelines in the distribution network operating above 1,050 kPag. AS 2885 applies to the design, construction and operation of pipelines and associated piping and components that are used to transmit single-phase and multi-phase hydrocarbon fluids and CO_2.

Although AS 2885 was not developed considering hydrogen as a fluid it can apply for transport of other fluids, under Clause 1.2.2 of AS 2885.0. This includes non-hydrocarbon gases such as hydrogen, but the Standard notes that the application of this requires special consideration.

The latest revision of AS 2885 was issued in December 2018 with publication of the next revision expected in 2023/2024 (nominal five-year revision cycle). It is likely in the next revision of AS 2885 that hydrogen will be incorporated as a fluid covered specifically under the scope of the Standard and provisions developed that address the design requirements impacted, in particular for material selection, design factor selection, fracture control, fatigue and welding.

As an interim measure, a Hydrogen Pipelines Code of Practice (CoP) is planned to be published by the Future Fuels Cooperative Research Centre in 2022, to provide guidance to the industry on the application of hydrogen under the AS 2885 series. It is expected that, as research continues both nationally and internationally into hydrogen embrittlement, the design requirements will evolve to support further revisions of the CoP and the next revision of the AS 2885 series.

However, as appropriate rules do not currently exist for hydrogen and its interaction with carbon steels, AS 2885 cannot be followed in its entirety for hydrogen pipeline design. However, other international standards currently exist, with ASME B31.12 the most commonly adopted for hydrogen pipeline design.

ASME B31.12

The American hydrogen pipeline standard, ASME B31.12 was developed for hydrogen piping and pipeline design. ASME B31.12 provides two design pathways, Option A and Option B – the first, Option A, is to apply a low design factor, the second is to conduct specific testing of hydrogen embrittlement effect on the material.

Currently, the most common approach to accommodate the loss of steel toughness is to use a low “design factor” for the pipeline, that is, to limit the stress in the pipe material.

The method allows limits the steel grade to API 5L X52 or lower grades with hydrogen and applies material penalties for higher grades that effectively de-rate their strength to that of an X52 material.

For low strength materials, ASME B31.12 will permit up to 40 per cent of SMYS without any consideration of fracture properties (Clause PL-3.7 (b)), and it permits a standard design approach without analysis for up to 50 per cent of SMYS except in the most safety-critical location classes. As a comparison, AS 2885 under natural gas service allows design up to X70 steel and design stress for wall thickness up to 80 per cent of SMYS. Consequently, for hydrogen service under the ASME B31.12 standard a much heavier wall thickness is required than what is typically allowed for natural gas pipelines under AS 2885.

To design at higher design factors requires application of the Option B design which requires completion of experimental testing on the purchase line pipe steel initially developed for stress corrosion cracking. The testing requires demonstration of sustained fracture resistance in a pressurised gaseous environment for a period of time. The method is difficult to apply, expensive, and laboratories that can implement it are scarce.

Standard Applied

For the purpose of the Study, AS 2885 is the overarching standard applied for pipeline design.

For hydrogen service, ASME B31.12 will govern material selection and mechanical design.

GPA

APPENDIX 5B PIPELINE DESIGN LIMITATIONS

Natural Gas

For natural gas, the following design conditions have been used:

- A design factor of 72 per cent SMYS - in alignment with high pressure natural gas transmission assets that run through rural areas within Australia, design governed by AS 2885.1
- A material grade of API 5L Grade X65 PSL2 - a commonly used material grade for high pressure natural gas (such as the Dampier Bunbury Pipeline).
- An MAOP of 15.3 MPag - in alignment with Class 900# components.

Hydrogen

For hydrogen gas, the following design conditions have been used:

- A design factor of 50 per cent SMYS
- A material grade of API 5L Grade X52 PSL2

Option A design method has been applied with a low design factor of 50 per cent SMYS nominated and the material grade API 5L Grade X52 PSL2 chosen. No assessment for fatigue screening or fatigue crack growth has been applied, as it is assumed the pipelines will be operated to maintain a relatively constant operating pressure without any requirement for pipeline packing for storage. A discussion on fatigue life in hydrogen service can be found in section 0.

- A MAOP of 12.0 MPag

Additional strength derating under ASME B31.12 applies above 13.8 MPa (between a class 600 and class 900 design). A conservative upper pressure limit of 12 MPa has been selected for the Study, this pressure is below this limit for de-rating aligns with the target pressure for hydrogen transmission pipelines under the US Department of Energy[37] and is similar to class 900 component ratings for associated pipe fittings and valves for associated facilities constructed from ASTM 316L stainless steels.

With reference to Figure 32, showing toughness reduction for a range of carbon steel materials, it supports that at around 7 MPa hydrogen, the toughness can be halved or worse. The toughness beyond this pressure drops off more gradually. The difference in effects of hydrogen between 7 MPa and 12 MPa is not nearly as significant as the effects between 2 MPa and 7 MPa – as the reduction in fracture toughness begins to plateau.

[37] https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery

Table 3.2.1.1. Fracture toughness for carbon steels in hydrogen gas at room temperature. The fracture toughness in air, nitrogen, or helium is included for comparison. The crack propagation direction is parallel to the longitudinal orientation of the material product form.

Steel	S_y † (MPa)	RA † (%)	Test environment	Displ. rate (mm/s)	K_{Ic} ($MPa \cdot m^{1/2}$)	K_{IH} ‡ ($MPa \cdot m^{1/2}$)	dJ/da (MPa)	Ref.
A516	375	69	Air	8.5×10^{-3}	166*		516	[8, 9]
			3.5 MPa H_2			131	47	
			6.9 MPa H_2			113	55	
			20.7 MPa H_2			98	54	
			34.5 MPa H_2			90	57	
1080	414	16	6.9 MPa N_2	2.5×10^{-4} - 2.5×10^{-3}	111		42	[5]
			6.9 MPa H_2			81	13	
X42	366	56	6.9 MPa N_2	2.5×10^{-4} - 2.5×10^{-3}	178*		70	[5, 6, 10]
			6.9 MPa H_2			107	63	
X42	280	58	Air	$\leq 3.3 \times 10^{-4}$	147*		111	[11]
			2.0 MPa H_2			101-128	—	
			4.0 MPa H_2			85	36	
			6.5 MPa H_2			69	31	
			7.0 MPa H_2			73#	—	
			8.0 MPa H_2			59#	—	
			10.0 MPa H_2			53#	—	
			12.2 MPa H_2			57#	—	
			16.0 MPa H_2			46#	—	
X60	473	62	6.9 MPa He	8.5×10^{-3}	142		123	[8]
			6.9 MPa H_2			104	43	
X70	584	57	6.9 MPa N_2	2.5×10^{-4} - 2.5×10^{-3}	197		251	[6]
			6.9 MPa H_2			95	23	
X60	434	88	5.5 MPa H_2	8.3×10^{-5} - 8.3×10^{-4}	—	85	—	[18]
			21 MPa H_2			82		
X80	565	81	5.5 MPa H_2	8.3×10^{-5} - 8.3×10^{-4}	—	105	—	[18]
			21 MPa H_2			102		

† yield strength and reduction of area of smooth tensile specimen in air
‡ calculated from relationship $K = \sqrt{JE/1-\nu^2}$
* reported fracture toughness may not be valid plane strain measurement
# measured from burst tests on pipes with machined flaws

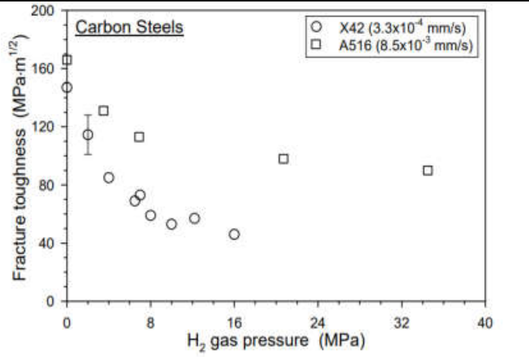

Figure 3.2.1.2. Effect of hydrogen gas pressure on fracture toughness for carbon steels [8, 9, 11]. The displacement rate used in the fracture toughness tests is indicated for each steel.

Figure 32: Fracture toughness reduction in Sandia technical database for hydrogen compatibility of materials (San Marchi & Somerday, 2012)

Diameter and Wall Thickness

Pipeline sizing will generally to be considered as feasible for the Study are nominal sizes between 4 inch (DN100) and 46 inch (DN1150), common for both gas mediums.

Internationally, the world's largest (in diameter) gas pipeline constructed is the Yamal-Europe pipeline at 56 inch (DN1400).

It should be noted that Australia's transmission networks are typically smaller diameter, high pressure pipelines due to greater distances required to be traversed between gas production and major end use customers. Australia has had some recent experience with larger diameter pipeline projects, primarily the export pipelines from coal seam fields for export via LNG, such as the three 42-inch APLNG, GLNG pipelines and the WGP (Wallumbilla Gas Pipeline). Largest size pipelines present greater material supply challenges, more specialist construction equipment and a higher risk in successful design and construction.

The lower end of the size range (4 inch) is the approximate minimum diameter that will allow transport of an internal inspection tool (intelligent pig) carried in the gas stream over a reasonable distance. Intelligent internal inspection is critical for maintaining high-pressure long-distance pipelines in safe operating service, in order to monitor and measure external corrosion and defect growth, including sharp defects subject to fatigue cycles.

The wall thickness of the pipeline shall be limited to a minimum of 3.2mm as per AS 2885.2 Section 1.1, this is also a lower limit on what is comfortable for girth welds in high pressure gas transmission. Pipeline thickness greater than 31.8mm is outside of the standard thicknesses listed in ASME B36.10, although can be used under special manufacturing circumstances. Pipeline thicknesses will round up to the nearest ASME B36.10 size with the exception of thicknesses above 31.8mm: above 31.8mm will be rounded to the nearest 0.1mm and is assumed a custom thickness.

Parallel Pipelines

Parallel pipelines present some operational challenges with more constraints around access for inspections and repairs, as well as a wider easement and therefore increased land tenure requirements. However, parallel pipelines are not uncommon in pipeline industry experience, and are considered a feasible solution (such as the twinned 14 inch 300km sections of the SEA Gas pipeline) or as part of subsequent looping projects to increase capacity enhancement (e.g. the QGP looping projects or the DBNGP). Doubling or tripling the pipeline does not equate to a directly proportional cost increase: there are cost savings across project execution, engineering, regulatory approvals and land tenure negotiations as well as construction workforce and equipment. This is likely in the order of 10-20 per cent cost reduction for the second pipeline when constructed at the same time.

There are difficulties with maintenance as well as construction, access of the central pipeline in a triple parallel pipeline arrangement is very limited. Terrain will also dictate the feasibility of running parallel lines due to corridor width requirements. Project B is a good example of this. Where a pipeline is required to follow a ridge line, a larger right of way (ROW) may not necessarily be possible, having a second pipeline within the same trench will demand approximately 1.5 times the clearing for the pipeline row. A single larger pipeline is also cheaper with respect to welding, HDD, testing (hydro and weld), MLV and facilities and maintenance.

Fatigue Life

Fatigue can initiate new defects over long periods of time, but more often leads to growth of defects that already exist. It is a slow crack-growth mechanism caused by cycling of stress in the pipeline. Under the right conditions, fatigue can cause a crack to grow to the point that it reaches a critical length and failure occurs.

Gas pipelines operated in a “pack-and-deplete” regime (such as gas storage pipelines designed to optimise revenue from the fluctuating gas and electricity price) or with a high design factor (high stress in the pipe wall) may see sufficient cycling to require the consideration for potential fatigue damage. Pipelines are not usually intended for repeated exposure to full pressure cycles, so pipelines that have been completely blown down and re-pressurised several times may also be at risk of fatigue damage. A small number of large cycles contribute the largest proportion of damage and these should be carefully controlled and avoided – especially full emptying and filling operations.

The researched effect of cycling pressures in hydrogen service suggests the fatigue life can be reduced by a factor of 10 when compared to natural gas (as shown in Figure 33). For a well-designed pipeline with minimal pressure cycling, this is not a concern – it is not uncommon for pipelines to have a fatigue life well above 100 years with a comfortable margin of safety. This can be quickly reduced under pressure cycling scenarios and must be considered in future design stages.

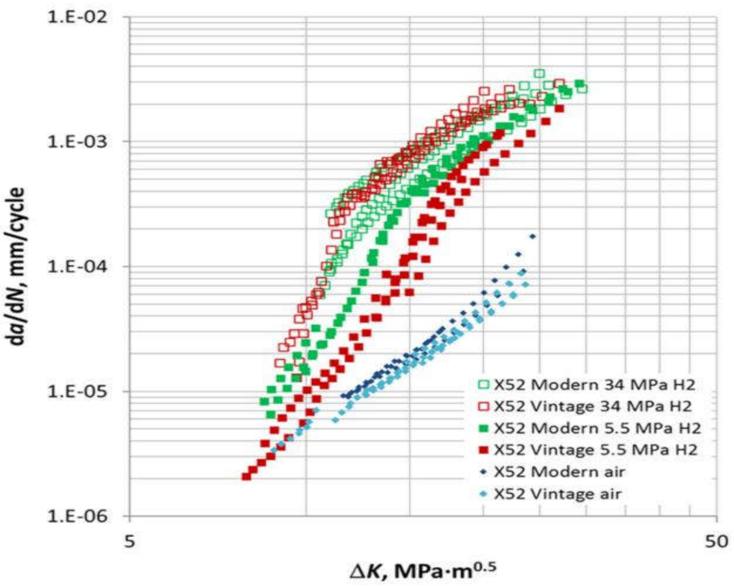

Figure 33: Fatigue crack growth rate of X52 steel tested at hydrogen pressures of 34 MPa and 5.5 MPa (Slifka, et al., 2018)

Fatigue was not specifically assessed in The Study, as the cyclic frequency has not been defined, however it is expected the low design factor selected (0.5) will provide a suitably long design life for most transmission pipeline scenarios. It is recommended for individual pipeline projects that a fatigue screening assessment is performed early in the project, if pressure cycling is expected, due to the impact of hydrogen on fatigue crack growth rates and therefore on fatigue life.

APPENDIX 6 PIPELINE PROCESS MODELLING CASES AND BASIS

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APPENDIX 6A DESIGN CASES

Based on the project Case Matrix provided in Appendix 1, assuming two different fluids, hydrogen gas and natural gas, the following scenarios were considered during the Study:

- Base Cases, without consideration of storage requirements;
- Four hours storage capacity scenarios;
- 12 hours storage capacity scenarios; and
- 24 hours storage capacity scenarios.

Four different throughput capacities (10 TJ/d, 50 TJ/d, 250 TJ/d and 500 TJ/d) and four different pipeline lengths (25 km, 100 km, 250 km and 500 km) are considered for each scenario.

Combining these parameters led to 128 different cases for process modelling of natural gas and hydrogen gas as the transmission carriers. The summary of design cases is presented in Appendix 1.

There is a specific name for each case which is created as follows:

Carrier type (NG/HG) **- Storage time**(0/4/12/24) **- Capacity** (10/50/250/500) **- Pipeline length**(25/100/250/500)

The mass flowrate (tonne/h) was calculated from the energy value (TJ/d) by considering the gross heating values of 12.10 MJ/Sm^3 and 37.78 MJ/Sm^3 for hydrogen and natural gas, respectively, and the standard density of 0.0853 kg/m^3 for hydrogen gas and 0.0771 kg/m^3 for natural gas (refer to *hydrogen and natural gas properties*).

APPENDIX 6B PIPELINE SIZE SELECTION METHOD AND DESIGN CRITERIA

Pipeline sizing was performed using HYSYS process simulation software.

For the main cases (i.e., Base Cases, without consideration of storage requirements):

- The pipeline inlet pressure is set at the maximum allowable operating pressure (MAOP).
- The minimum pipe size is determined such that the outlet pressure is above 3,000 kPag and the maximum gas velocity remains within the erosional velocity criteria (i.e., erosion velocity ratio (EVR) less than 0.8).
- After the minimum applicable pipeline size is selected, the minimum allowable inlet pressure is determined by decreasing the inlet pressure until the outlet pressure is above 3,000 kPag and EVR at the pipe outlet is at (or just below) the limit of 0.8.

Note: A pipeline outlet pressure of 3,000 kPag (minimum) has been assumed when determining minimum pipeline size; for the following reasons:

1. This pressure corresponds to the minimum realistic pipeline off take pressure at a regulator station; and
2. This pressure level represents a realistic suction pressure for compressor stations required on longer pipeline lengths, that is limits compression ratio to about 3-4 (the limit of single-stage compression).

For the storage scenarios, the following steps were followed:

1. Based on a pipeline outlet pressure of 3,000 kPag (or higher, if necessary, to keep the EVR less than 0.8), the settle-out pressure for the Base Case pipe size is calculated. This corresponds to the pipeline settle-out pressure at the end of the depletion period.
2. At the settle-out pressure (calculated at Step-1), the total mass within the pipeline is calculated.
3. Summing up the calculated mass in Step-2 and the required storage capacity for each storage scenario, the required total mass at the start of the depletion period is calculated.
4. Based on the total mass at Step-3 and pipeline volume, the required density and settle-out pressure before depletion period initiation is obtained.
5. Using the HYSYS simulation package, the pipeline inlet pressure corresponding to the Step-4 (start of depletion) settle-out pressure is determined.
6. The inlet pressure is checked against the MAOP. If the required inlet pressure is higher than MAOP, the above steps are repeated for the next larger pipe size. Otherwise, the required inlet and outlet pressures before initiating the depletion period are reported.

The same approach is used for the storage scenarios where parallel pipelines are required due to the 46” limit on pipeline size (maximum practical size).

Velocity Criteria

API RP 14E provides guidance on maximum velocity limits for carbon steel piping material. Velocities lower than the erosional velocity are recommended.

$$V_e = \frac{1.22c}{\sqrt{\rho_m}}$$

Where:

V_e: Erosional Velocity (m/s)

c: 100 (for solids free fluid)

ρ_m: Density (kg/m^3)

A similar equation is provided in ASME B31.12 for hydrogen pipelines.

In the Study, for both hydrogen and natural gas fluids, the pipeline size is selected so that the velocity along the pipeline does not exceed 80 per cent of the erosional velocity (i.e. erosional velocity ratio (EVR) is less than 0.8). Note, however, that the EVR limit is not always the governing sizing criteria – this is particularly true for the cases where fluid enters the pipeline at the MAOP, and the pipeline outlet pressure is higher than 3,000-5,000 kPag. In these cases, pipeline size is determined by the available pressure drop i.e., a smaller pipeline size would result in an outlet pressure less than 3,000 kPag, even though the EVR is less than 0.8.

Process Modelling Data and Assumptions

The process modelling is based on the following design data and assumptions:

- HYSYS simulation software with Peng Robinson Property Package and Beggs and Brill fluid correlation is used for simulations;
- No elevation change is taken between the inlet and outlet of the pipeline (it would not affect the single-phase gas pipeline simulation results);
- Actual wall thickness values for pressure containment are estimated based on wall thickness calculations as per ASME B31.12 and ASME B31.8 using API 5L Grade X52 PSL2 carbon steel;
- Pipe material heat conductivity is 45 W/mK;
- No insulation is assumed for the pipeline;
- 46-inch pipe diameter is assumed as the maximum practical pipe size;
- Absolute pipe roughness is 0.045 mm;
- The burial depth is 900 mm for the entire length of the pipeline;
- Ground thermal conductivity is 0.17 W/mK (not considered critical as the gas temperature approaches ground temperature after a few kilometres);
- The ambient ground temperature is 35 °C (1 m underground summer temperature);
- Fluid composition is 100 per cent hydrogen dry gas for hydrogen fluid;
- Fluid composition for natural gas is based on a typical central Australia sales gas composition (refer to *hydrogen and natural gas properties*);
- Pipeline MAOP for the hydrogen fluid is 12 MPa(g) (the maximum comfortable pressure to avoid hydrogen embrittlement in carbon steel pipelines);
- Pipeline MAOP for the natural gas fluid is 15.3 MPa(g); and
- The fluid inlet temperature is 50 °C;

Natural Gas Composition

A typical Australian Natural Gas Composition is selected for The Study as shown in Table 20.

Table 20: Natural Gas composition

Element	Unit	Value
Methane	mol%	95.709
Ethane	mol%	2.369
Propane	mol%	0.071
i-Butane	mol%	0.004
n-Butane	mol%	0.008
i-Pentane	mol%	0.002
n-Pentane	mol%	0.006
n-Hexane	mol%	0.016
n-Heptane	mol%	0.000
n-Octane	mol%	0.000
n-Nonane	mol%	0.000
Nitrogen	mol%	1.274
CO2	mol%	0.541
Hydrogen	mol%	0

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GPA ENGINEERING	Document Title	Document Number	Rev
	Energy Value Equivalent Flowrate	210739-CALC-001	0

Scenario/Design Case	Natural Gas				
		Scenario/Design Case Input Data			
Tag #		**Units**	**Metric**	**Key**	**Input**
Equipment #					**Calculated**
Location					
P&ID #					

Input data

Description	Definition	Source	Symbol	Units	Value
	Gas Composition				
Component			y_i	mole fraction	
Methane					0.9571
Ethane					0.0237
Propane					0.0007
i-Butane					0.0000
n-Butane					0.0001
i-Pentane					0.0000
n-Pentane					0.0001
n-Hexane					0.0002
n-Heptane					0.0000
n-Octane					0.0000
n-Nonane					0.0000
Carbon dioxide					0.0054
Hydrogen					0.0000
Oxygen					0.0000
Nitrogen					0.0127
Water					0.0000
Total					1.000

Calculation and Results

Description	Formula/ criteria	Section/ref	Symbol	Units	Value
	Gas properties				
Gas molecular mass			*MW*	*kg/kmol*	16.719
Specific gravity rel. to air			*SG*	-	0.577
Gas standard density (Z = 1)			ρ	*kg/std.m*^{3}	0.7071
Gross heating value			*GHV*	*MJ/std.m*^{3}	37.78
				MJ/kg	53.43
Net heating value			*NHV*	*MJ/std.m*^{3}	34.04
				MJ/kg	48.14
Wobbe number (from GHV)			*W#*	-	49.72

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Hydrogen and Gas Properties

GPA ENGINEERING	Document Title		Document Number		Rev
	Energy Value Equivalent Flowrate		210739-CALC-001		0

Scenario/Design Case	Pure Hydrogen

Scenario/Design Case Input Data

Tag #			Units	Metric	Key	Input
Equipment #						Calculated
Location						
P&ID #						

Input data

Description	Definition	Source	Symbol	Units	Value
Gas Composition					
Component			y_i	mole fraction	
Methane					0.0000
Ethane					0.0000
Propane					0.0000
i-Butane					0.0000
n-Butane					0.0000
i-Pentane					0.0000
n-Pentane					0.0000
Neopentane					0.0000
n-Hexane					0.0000
Carbon dioxide					0.0000
Hydrogen					1.0000
Nitrogen					0.0000
Total					1.000

Calculation and Results

Description	Formula/ criteria	Section/ref	Symbol	Units	Value
Gas properties					
Gas molecular mass			*MW*	*kg/kmol*	2.016
Specific gravity rel. to air			*SG*	-	0.070
Gas standard density (Z = 1)			ρ	*kg/std.m^3*	0.0853
Gross heating value			*GHV*	*MJ/std.m^3*	12.102
				MJ/kg	141.95
Net heating value			*NHV*	*MJ/std.m^3*	10.22
				MJ/kg	119.91
Wobbe number (from GHV)			*W#*	-	45.87

APPENDIX 7 PIPELINE PROCESS SIZING RESULTS

The results of the pipeline sizing study for different design scenarios are provided in this section. In some storage scenarios, the results indicate that it is impossible to cover the required storage capacity with a single pipeline configuration (maximum applicable pipe size is 46”), and parallel pipelines are required. Therefore, a study was completed to consider parallel pipelines for storage cases where a single pipeline configuration is not applicable.

APPENDIX 7A 25 KM PIPELINE LENGTH

Table 21 presents the simulation results of the different scenarios for transmission of natural gas/ hydrogen gas with a pipeline length of 25 km.

Table 21: 25 km pipeline length – results

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)	Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
							Minimum Allowable Inlet Pressure for Base Cases						
Base Cases	Natural Gas	10	7.798	1	NG-10-0-25	0	6,880	3,000	N/A	12.2	26.3	0.47	**4**
		50	38.992	2	NG-50-0-25	0	10,730	4,500	N/A	16.8	21.3	0.79	**6**
		250	194.961	3	NG-250-0-25	0	11,890	8,000	N/A	12.2	15.6	0.78	**12**
		500	389.922	4	NG-500-0-25	0	15,300	11,900	N/A	10.0	12.5	0.80	**16**
	Hydrogen	10	2.937	5	HG-10-0-25	0	7,816	3,000	N/A	41.2	78.5	0.52	**4**
		50	14.684	6	HG-50-0-25	0	6,697	3,000	N/A	52.1	78.5	0.66	**8**
		250	73.421	7	HG-250-0-25	0	11,620	8,000	N/A	38.1	49.1	0.78	**14**
		500	146.842	8	HG-500-0-25	0	10,440	8,000	N/A	37.5	49.1	0.77	**20**
							Start of Depletion Phase for Storage Cases		End of Depletion Phase for Storage Cases				
Storage- 4 hours	Natural Gas	10	7.798	9	NG-10-4-25	31,194	11,100	10,930	3000	5.1	26.3	0.20	**6**
		50	38.992	10	NG-50-4-25	155,969	13,700	13,590	3000	7.0	26.3	0.26	**12**
		250	194.961	11	NG-250-4-25	779,844	13,900	13,850	3000	7.2	26.3	0.27	**28**
		500	389.922	12	NG-500-4-25	1,559,688	14,700	14,660	3000	7.8	26.3	0.30	**38**
	Hydrogen	10	2.937	13	HG-10-4-25	11,747	12,000	11,990	3000	4.9	78.5	0.06	**12**
		50	14.684	14	HG-50-4-25	58,737	11,100	11,100	3000	4.4	78.5	0.06	**30**
		250	73.421	15	HG-250-4-25	293,684	11,550	11,550	3000	4.7	78.5	0.06	**2 X 46**
		500	146.842	16	HG-500-4-25	587,368	11,550	11,550	3000	4.7	78.5	0.06	**4 X 46**
Storage- 12 hours	Natural Gas	10	7.798	17	NG-10-12-25	93,581	11,800	11,790	3000	2.0	26.3	0.08	**10**
		50	38.992	18	NG-50-12-25	467,906	13,400	13,390	3000	2.4	26.3	0.09	**22**
		250	194.961	19	NG-250-12-25	2,339,531	14,850	14,850	3000	2.8	26.3	0.11	**46**
		500	389.922	20	NG-500-12-25	4,679,063	14,850	14,850	3000	2.8	26.3	0.11	**2 X 46**
	Hydrogen	10	2.937	21	HG-10-12-25	35,242	10,550	10,550	3000	1.4	78.5	0.02	**24**
		50	14.684	22	HG-50-12-25	176,211	11,400	11,400	3000	1.6	78.5	0.02	**2 X 36**
		250	73.421	23	HG-250-12-25	881,053	11,550	11,550	3000	1.6	78.5	0.02	**6 X 46**
		500	146.842	24	HG-500-12-25	1,762,105	11,550	11,550	3000	1.6	78.5	0.02	**12 X 46**
Storage- 24 hours	Natural Gas	10	7.798	25	NG-10-24-25	187,163	13,300	13,300	3000	1.2	26.3	0.05	**14**
		50	38.992	26	NG-50-24-25	935,813	14,200	14,200	3000	1.3	26.3	0.05	**30**
		250	194.961	27	NG-250-24-25	4,679,063	14,850	14,850	3000	1.4	26.3	0.05	**2 X 46**
		500	389.922	28	NG-500-24-25	9,358,126	14,850	14,850	3000	1.4	26.3	0.05	**4 X 46**
	Hydrogen	10	2.937	29	HG-10-24-25	70,484	11,500	11,500	3000	0.8	78.5	0.01	**32**

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)	Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
							Minimum Allowable Inlet Pressure for Base Cases						
		50	14.684	30	HG-50-24-25	352,421	9,850	9,850	3000	0.6	78.5	0.01	**3 X 46**
		250	73.421	31	HG-250-24-25	1,762,105	11,550	11,550	3000	0.8	78.5	0.01	**12 X 46**
		500	146.842	32	HG-500-24-25	3,524,211	11,900	11,900	3000	0.8	78.5	0.01	**23 X 46**

Figure 34 compares the selected pipe size of natural gas and hydrogen gas for each scenario.

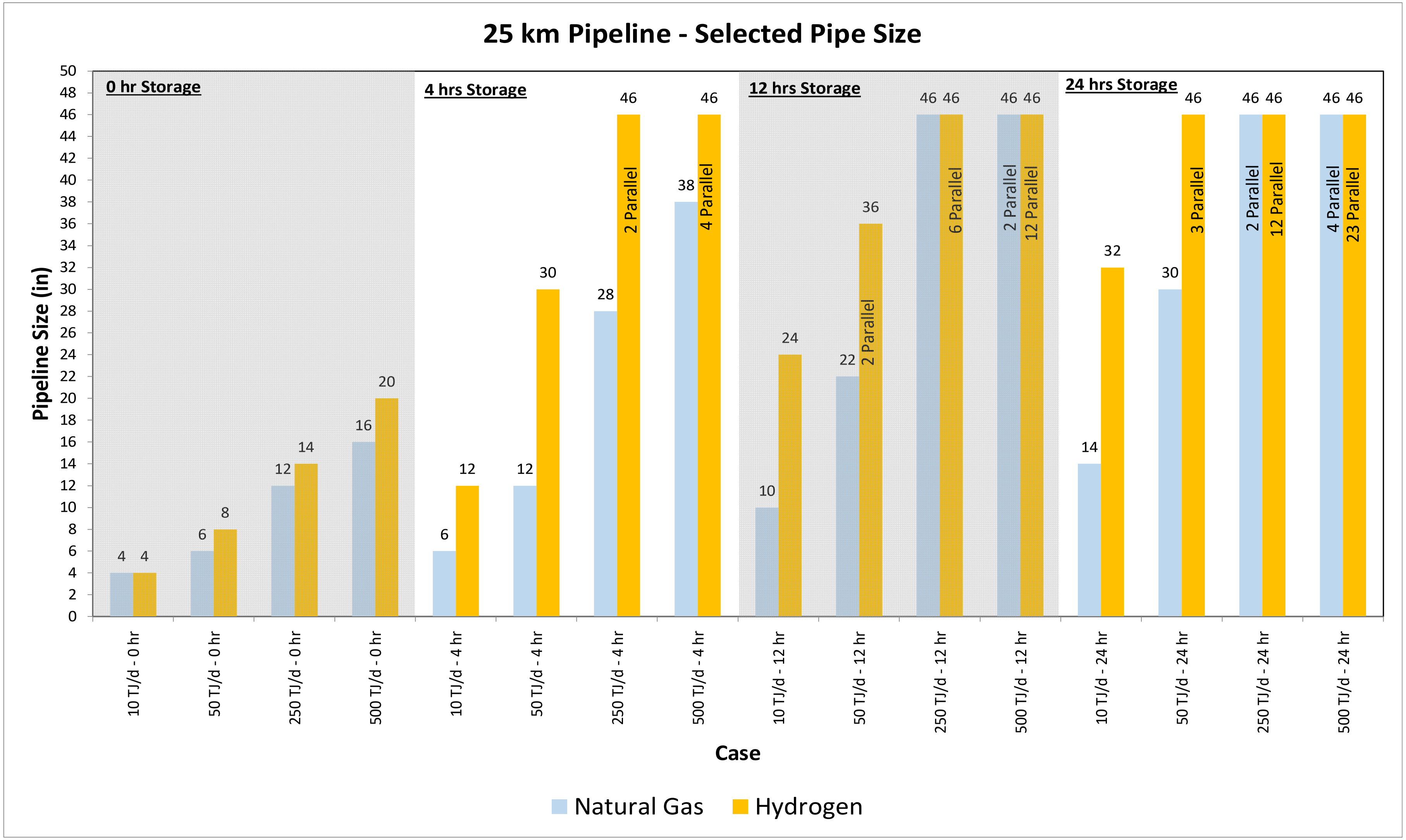

Figure 34: Required pipeline size – 25 km pipeline length

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APPENDIX 7B 100 KM PIPELINE LENGTH

Table 22 presents the simulation results of the different scenarios for transmission of natural gas/ hydrogen gas fluids with a pipeline length of 100 km.

Table 22: 100 km pipeline length – results

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)		Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
								Minimum Allowable Inlet Pressure for Base Cases						
Base Cases	Natural Gas	10	7.798		33	NG-10-0-100	0	12500	3000	N/A	12.2	26.3	0.47	**4**
		50	38.992		34	NG-50-0-100	0	10380	3000	N/A	15.2	26.3	0.58	**8**
		250	194.961		35	NG-250-0-100	0	14810	5500	N/A	15.2	19.1	0.80	**14**
		500	389.922		36	NG-500-0-100	0	12270	5500	N/A	14.9	19.1	0.78	**20**
	Hydrogen	10	2.937		37	HG-10-0-100	0	5740	3000	N/A	17.8	78.5	0.23	**6**
		50	14.684		38	HG-50-0-100	0	7351	3000	N/A	33.2	78.5	0.42	**10**
		250	73.421		39	HG-250-0-100	0	9315	3000	N/A	59.5	78.5	0.76	**18**
		500	146.842		40	HG-500-0-100	0	11600	5000	N/A	48.6	61.8	0.79	**22**
								Start of Depletion Phase for Storage Cases		End of Depletion Phase for Storage Cases				
Storage- 4 hours	Natural Gas	10	7.798		41	NG-10-4-100	31,194	15200	9409	3000	12.2	26.3	0.47	**4**
		50	38.992		42	NG-50-4-100	155,969	14300	10510	3000	15.2	26.3	0.58	**8**
		250	194.961		43	NG-250-4-100	779,844	13050	10920	3000	17.4	26.3	0.66	**18**
		500	389.922		44	NG-500-4-100	1,559,688	13500	11700	3000	19.6	26.3	0.74	**24**
	Hydrogen	10	2.937		45	HG-10-4-100	11,747	8550	8173	3000	10.4	78.5	0.13	**8**
		50	14.684		46	HG-50-4-100	58,737	10700	10410	3000	15.1	78.5	0.19	**16**
		250	73.421		47	HG-250-4-100	293,684	11150	11010	3000	16.7	78.5	0.21	**34**
		500	146.842		48	HG-500-4-100	587,368	11800	11690	3000	18.1	78.5	0.23	**46**
Storage- 12 hours	Natural Gas	10	7.798		49	NG-10-12-100	93,581	10200	9414	3000	5.1	26.3	0.20	**6**
		50	38.992		50	NG-50-12-100	467,906	11950	11410	3000	7.0	26.3	0.26	**12**
		250	194.961		51	NG-250-12-100	2,339,531	14950	14560	3000	9.8	26.3	0.37	**24**
		500	389.922		52	NG-500-12-100	4,679,063	14600	14340	3000	9.8	26.3	0.37	**34**
	Hydrogen	10	2.937		53	HG-10-12-100	35,242	9800	9755	3000	4.8	78.5	0.06	**12**
		50	14.684		54	HG-50-12-100	176,211	11100	11080	3000	5.8	78.5	0.07	**26**
		250	73.421		55	HG-250-12-100	881,053	11600	11580	3000	6.2	78.5	0.08	**2 X 40**
		500	146.842		56	HG-500-12-100	1,762,105	11600	11590	3000	6.2	78.5	0.08	**3 X 46**
Storage- 24 hours	Natural Gas	10	7.798		57	NG-10-24-100	187,163	10200	10000	3000	3.0	26.3	0.12	**8**
		50	38.992		58	NG-50-24-100	935,813	13250	13100	3000	4.4	26.3	0.17	**16**
		250	194.961		59	NG-250-24-100	4,679,063	14100	14030	3000	4.9	26.3	0.19	**34**
		500	389.922		60	NG-500-24-100	9,358,126	15000	14950	3000	5.3	26.3	0.20	**46**
	Hydrogen	10	2.937		61	HG-10-24-100	70,484	11600	11590	3000	3.1	78.5	0.04	**16**
		50	14.684		62	HG-50-24-100	352,421	11400	11400	3000	3.1	78.5	0.04	**36**

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)		Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
								Minimum Allowable Inlet Pressure for Base Cases						
		250	73.421		63	HG-250-24-100	1,762,105	11550	11550	3000	3.2	78.5	0.04	**3 X 46**
		500	146.842		64	HG-500-24-100	3,524,211	11550	11550	3000	3.2	78.5	0.04	**6 X 46**

Figure 35 compares the selected pipe size of Natural gas and Hydrogen gas for each scenario.

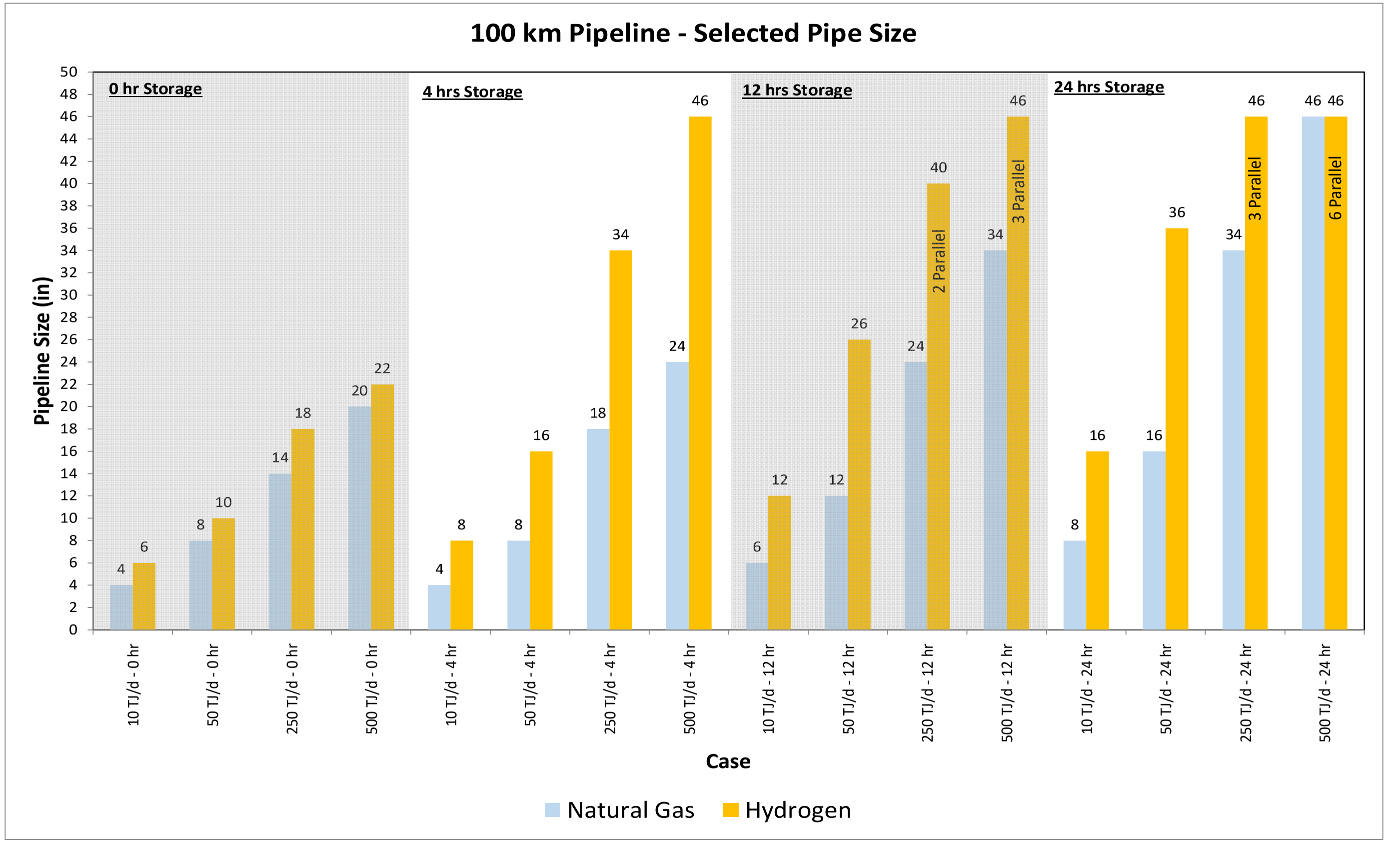

Figure 35: Required pipeline size –100 km pipeline length

APPENDIX 7C 250 KM PIPELINE LENGTH

Table 23 presents the simulation results of the different scenarios for transmission of natural gas/ hydrogen gas fluids with a pipeline length of 250 km.

Table 23: 250 km Pipeline Length –Results

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)	Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
							Minimum Allowable Inlet Pressure for Base Cases						
Base Cases	Natural Gas	10	7.798	65	NG-10-0-250	0	7043	3000	N/A	5.1	26.3	0.20	**6**
		50	38.992	66	NG-50-0-250	0	9409	3000	N/A	9.8	26.3	0.37	**10**
		250	194.961	67	NG-250-0-250	0	11890	3000	N/A	17.4	26.3	0.66	**18**
		500	389.922	68	NG-500-0-250	0	14090	4000	N/A	17.3	22.6	0.76	**22**
	Hydrogen	10	2.937	69	HG-10-0-250	0	8339	3000	N/A	17.8	78.5	0.23	**6**
		50	14.684	70	HG-50-0-250	0	11100	3000	N/A	33.2	78.5	0.42	**10**
		250	73.421	71	HG-250-0-250	0	11040	3000	N/A	48.1	78.5	0.61	**20**
		500	146.842	72	HG-500-0-250	0	11120	3000	N/A	56.8	78.5	0.72	**26**
							Start of Depletion Phase for Storage Cases		End of Depletion Phase for Storage Cases				
Storage- 4 hours	Natural Gas	10	7.798	73	NG-10-4-250	31,194	7550	4093	3000	5.1	26.3	0.20	**6**
		50	38.992	74	NG-50-4-250	155,969	10300	5272	3000	9.8	26.3	0.37	**10**
		250	194.961	75	NG-250-4-250	779,844	13300	6881	3000	17.4	26.3	0.66	**18**
		500	389.922	76	NG-500-4-250	1,559,688	12900	7118	3000	19.5	26.3	0.74	**24**
	Hydrogen	10	2.937	77	HG-10-4-250	11,747	10800	7411	3000	17.8	78.5	0.23	**6**
		50	14.684	78	HG-50-4-250	58,737	11000	8523	3000	23.6	78.5	0.30	**12**
		250	73.421	79	HG-250-4-250	293,684	10800	9327	3000	28.4	78.5	0.36	**26**
		500	146.842	80	HG-500-4-250	587,368	11600	10240	3000	33.3	78.5	0.42	**34**
Storage- 12 hours	Natural Gas	10	7.798	81	NG-10-12-250	93,581	8700	6013	3000	5.1	26.3	0.20	**6**
		50	38.992	82	NG-50-12-250	467,906	12400	8805	3000	9.8	26.3	0.37	**10**
		250	194.961	83	NG-250-12-250	2,339,531	13900	10920	3000	14.1	26.3	0.54	**20**
		500	389.922	84	NG-500-12-250	4,679,063	15000	12230	3000	16.7	26.3	0.64	**26**
	Hydrogen	10	2.937	85	HG-10-12-250	35,242	10300	9498	3000	10.4	78.5	0.13	**8**
		50	14.684	86	HG-50-12-250	176,211	10600	10190	3000	11.9	78.5	0.15	**18**
		250	73.421	87	HG-250-12-250	881,053	12000	11760	3000	14.9	78.5	0.19	**36**
		500	146.842	88	HG-500-12-250	1,762,105	11900	11650	3000	14.9	78.5	0.19	**2 X 36**
Storage- 24 hours	Natural Gas	10	7.798	89	NG-10-24-250	187,163	10700	8713	3000	5.1	26.3	0.20	**6**
		50	38.992	90	NG-50-24-250	935,813	11700	10260	3000	7.0	26.3	0.26	**12**
		250	194.961	91	NG-250-24-250	4,679,063	14000	12940	3000	9.8	26.3	0.37	**24**
		500	389.922	92	NG-500-24-250	9,358,126	14900	14010	3000	11.0	26.3	0.42	**32**
	Hydrogen	10	2.937	93	HG-10-24-250	70,484	11050	10810	3000	6.7	78.5	0.08	**10**
		50	14.684	94	HG-50-24-250	352,421	10700	10610	3000	6.7	78.5	0.08	**24**

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)	Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
							Minimum Allowable Inlet Pressure for Base Cases						
		250	73.421	95	HG-250-24-250	1,762,105	11600	11530	3000	7.5	78.5	0.10	**2 X 36**
		500	146.842	96	HG-500-24-250	3,524,211	9900	9862	3000	6.1	78.5	0.08	**3 X 46**

Figure 36 compares the selected pipe size of natural gas and hydrogen gas for each scenario.

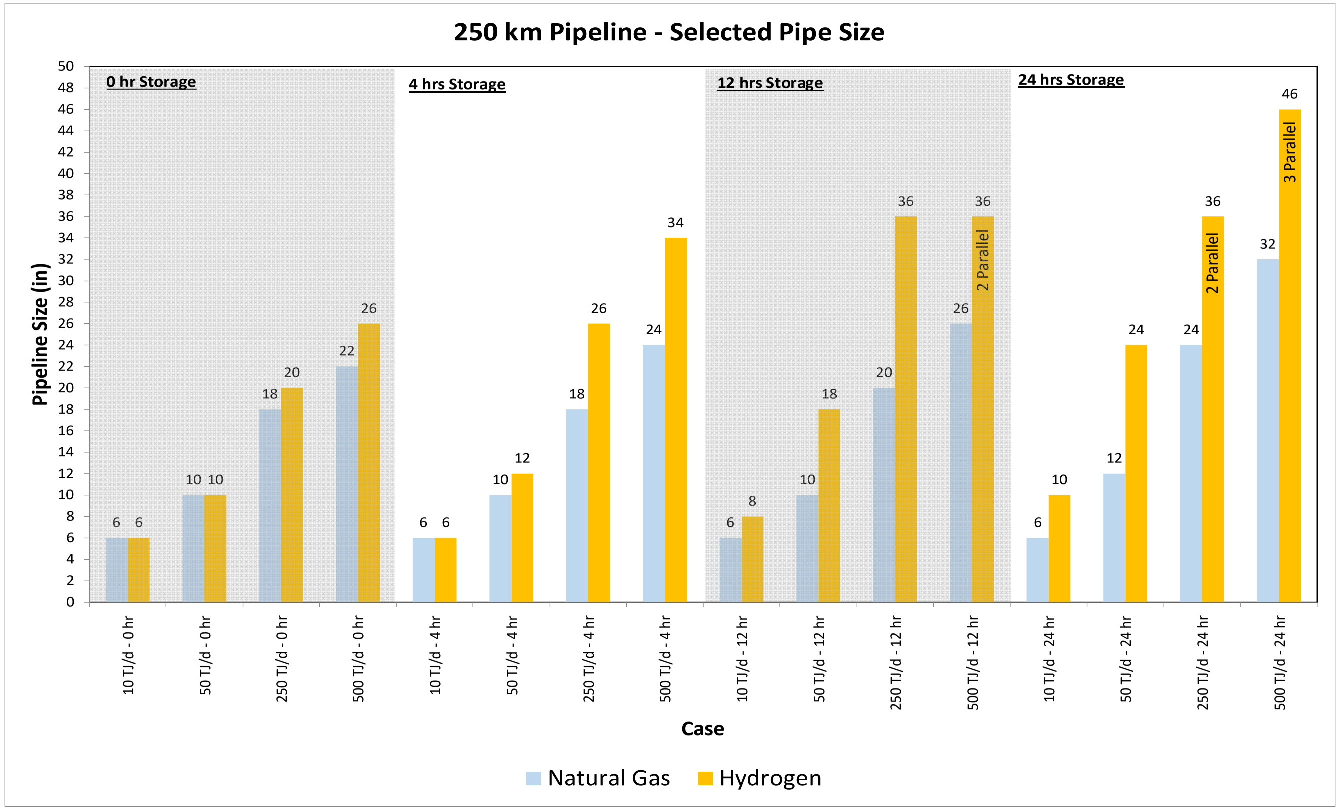

Figure 36: Required pipeline size – 250 km pipeline length

APPENDIX 7D 500 KM PIPELINE LENGTH

Table 24 presents the simulation results of the different scenarios for transmission of natural gas/hydrogen gas fluids with a pipeline length of 500 km.

Table 24: 500 km pipeline length – results

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)	Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
							Minimum Allowable Inlet Pressure for Base Cases						
Base Cases	Natural Gas	10	7.798	97	NG-10-0-500	0	9409	3000	N/A	5.1	26.3	0.19	**6**
		50	38.992	98	NG-50-0-500	0	12820	3000	N/A	9.8	26.3	0.37	**10**
		250	194.961	99	NG-250-0-500	0	12710	3000	N/A	14.1	26.3	0.54	**20**
		500	389.922	100	NG-500-0-500	0	12860	3000	N/A	16.7	26.3	0.63	**26**
	Hydrogen	10	2.937	101	HG-10-0-500	0	11470	3000	N/A	17.8	78.5	0.23	**6**
		50	14.684	102	HG-50-0-500	0	10200	3000	N/A	23.6	78.5	0.30	**12**
		250	73.421	103	HG-250-0-500	0	9812	3000	N/A	33.3	78.5	0.42	**24**
		500	146.842	104	HG-500-0-500	0	10870	3000	N/A	42.5	78.5	0.54	**30**
							Start of Depletion Phase for Storage Cases		End of Depletion Phase for Storage Cases				
Storage- 4 hours	Natural Gas	10	7.798	105	NG-10-4-500	31,194	9600	3593	3000	5.1	26.3	0.20	**6**
		50	38.992	106	NG-50-4-500	155,969	13150	4285	3000	9.8	26.3	0.37	**10**
		250	194.961	107	NG-250-4-500	779,844	13200	4783	3000	14.1	26.3	0.54	**20**
		500	389.922	108	NG-500-4-500	1,559,688	13400	4965	3000	16.7	26.3	0.64	**26**
	Hydrogen	10	2.937	109	HG-10-4-500	11,747	7100	4406	3000	10.4	78.5	0.13	**8**
		50	14.684	110	HG-50-4-500	58,737	11600	6194	3000	23.6	78.5	0.30	**12**
		250	73.421	111	HG-250-4-500	293,684	11900	7273	3000	33.3	78.5	0.42	**24**
		500	146.842	112	HG-500-4-500	587,368	11850	7713	3000	37.7	78.5	0.48	**32**
Storage- 12 hours	Natural Gas	10	7.798	113	NG-10-12-500	93,581	10050	4728	3000	5.1	26.3	0.20	**6**
		50	38.992	114	NG-50-12-500	467,906	13900	6346	3000	9.8	26.3	0.37	**10**
		250	194.961	115	NG-250-12-500	2,339,531	14400	7634	3000	14.1	26.3	0.54	**20**
		500	389.922	116	NG-500-12-500	4,679,063	14950	8448	3000	16.7	26.3	0.64	**26**
	Hydrogen	10	2.937	117	HG-10-12-500	35,242	8650	6593	3000	10.4	78.5	0.13	**8**
		50	14.684	118	HG-50-12-500	176,211	9750	8030	3000	15.1	78.5	0.19	**16**
		250	73.421	119	HG-250-12-500	881,053	11200	9848	3000	21.3	78.5	0.27	**30**
		500	146.842	120	HG-500-12-500	1,762,105	11750	10610	3000	23.9	78.5	0.30	**40**
Storage- 24 hours	Natural Gas	10	7.798	121	NG-10-24-500	187,163	10800	6235	3000	5.1	26.3	0.20	**6**
		50	38.992	122	NG-50-24-500	935,813	10750	7162	3000	7.0	26.3	0.26	**12**
		250	194.961	123	NG-250-24-500	4,679,063	13750	9924	3000	11.7	26.3	0.44	**22**
		500	389.922	124	NG-500-24-500	9,358,126	13300	10220	3000	12.5	26.3	0.48	**30**
	Hydrogen	10	2.937	125	HG-10-24-500	70,484	11300	9789	3000	10.4	78.5	0.13	**8**
		50	14.684	126	HG-50-24-500	352,421	11200	10410	3000	11.9	78.5	0.15	**18**

	Carrier Type	Total Capacity (TJ/day)	Flowrate (tonne/h)	Case No.	Case Name	Required Storage Capacity (kg)	Pipeline Inlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Pipeline Outlet Pressure (kPag)	Max. velocity (m/s)	Erosional Velocity (m/s)	EVR	Selected Pipe Size
							Minimum Allowable Inlet Pressure for Base Cases						
		250	73.421	127	HG-250-24-500	1,762,105	11300	10910	3000	13.3	78.5	0.17	**38**
		500	146.842	128	HG-500-24-500	3,524,211	11250	10860	3000	13.3	78.5	0.17	**2 X 38**

Figure 37 compares the selected pipe size of natural gas and hydrogen gas for each scenario.

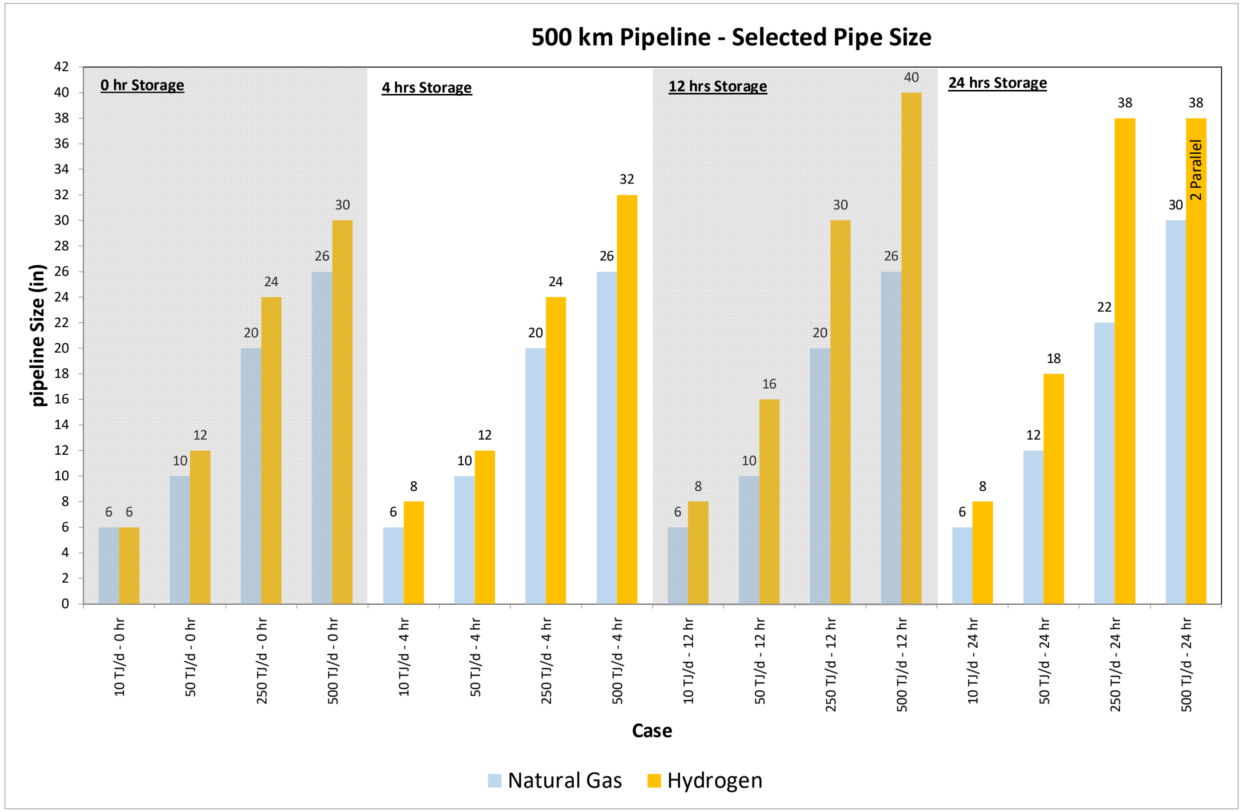

Figure 37: Required pipeline size – 500 km pipeline length

Figure 38 and Figure 39 summarise the selected pipe sizes for each case for natural gas and hydrogen gas, respectively.

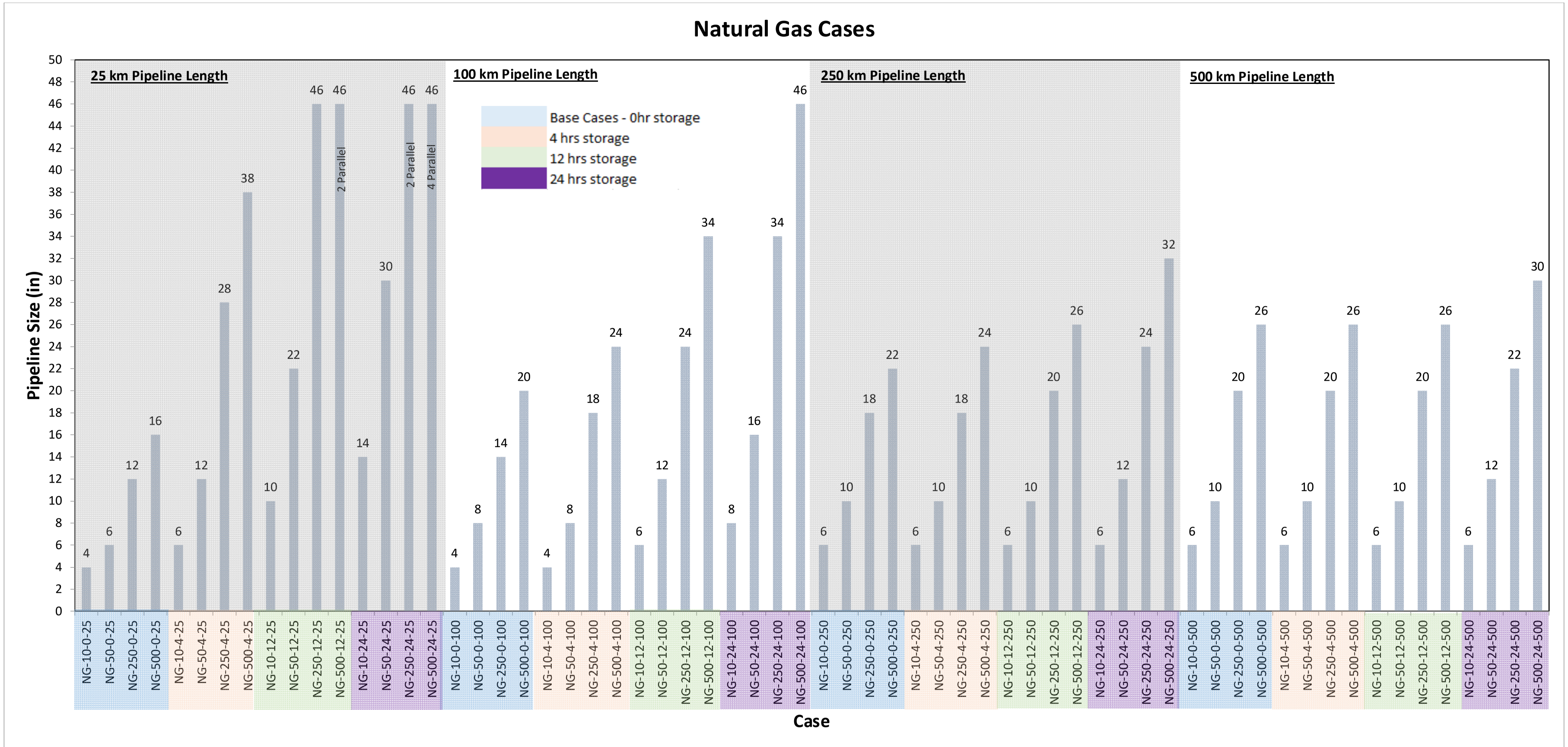

Figure 38: Required pipeline size – natural gas

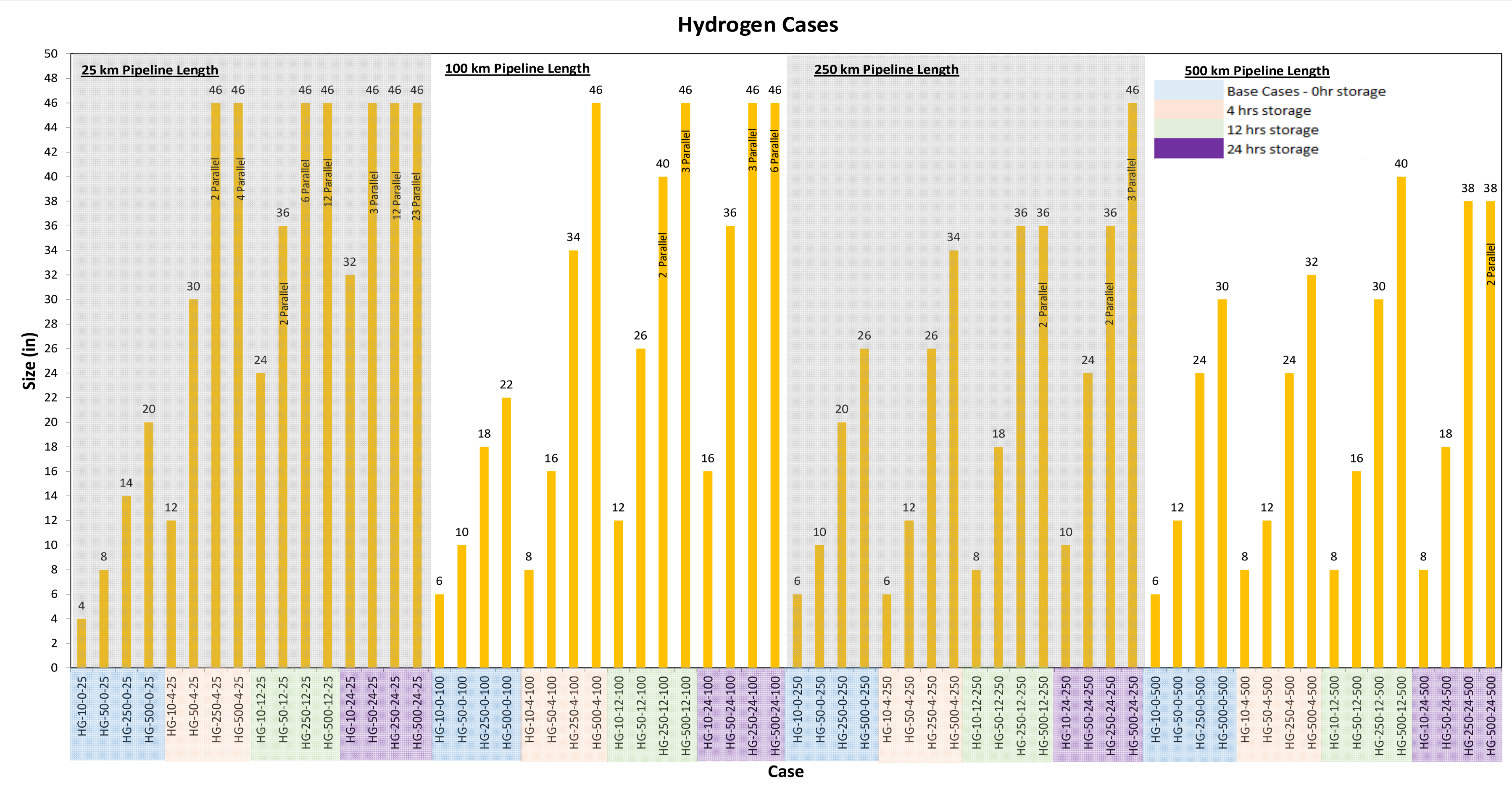

Figure 39: Required pipeline size – hydrogen gas

Above results indicate that:

- Due to the lower density of the hydrogen gas, the required pipe size for hydrogen pipeline is larger than the required pipe size for natural gas. This is true for both base cases and storage scenarios.

For the base cases, increasing the pipeline length increases the required pipeline size (or increases the required inlet pressure for the same size). However, for the storage scenarios, increasing the pipeline length decreases the required pipeline size since there is more volume and therefore more storage capacity for the longer pipelines.

APPENDIX 8 PIPELINE COST ESTIMATE BASIS

Estimate Class and Accuracy

The estimate has been prepared as an AACE Class 4 estimate, with a CAPEX accuracy of -30%/+50% commensurate with the early phase of the Study.

Escalation

The assumed notice to proceed stated in Q1 2025 has an assumed build out period of five years. Escalation has not currently been applied to account for this timing.

Contingency

A contingency has not been applied to the cost estimate.

Currency and Foreign Exchange

The estimate has been based on Australian Dollars (AUD) based on real term Q3 2021 values.

In some instances, prices provided in alternate currency (primarily USD) have been converted using the exchange rates in Figure 40 below.

Sep 1, 2021, 16:00 UTC

CURRENCY	NAME	UNITS PER AUD	AUD PER UNIT
USD	US Dollar	0.7368434046	1.3571404639
EUR	Euro	0.6217395445	1.6083905371
GBP	British Pound	0.5343213932	1.8715327756
INR	Indian Rupee	53.7706575292	0.0185975037
AUD	Australian Dollar	1.0000000000	1.0000000000
CAD	Canadian Dollar	0.9296316603	1.0756948614

Figure 40: Currency conversion factors (ref. www.xe.com/currencytables)

Approach and Methodology

Process modelling and fatigue modelling was completed to determine the operating pressure profile, pipeline size, erosional and fluid velocities.

Once pipeline sizing had been modelled, compressor model selection was undertaken in consultation with multiple international compressor vendors. Supplier consultation was undertaken to gain an understanding of current market commercial technologies across the range of process scenarios.

Once the pipeline case models were established with compression and linepipe scenarios confirmed, the second objective was to complete the total installed cost (TIC) estimate.

The CAPEX total installed cost (TIC) estimate is a factored estimate based on a combination of early vendor pricing as a material rate per tonne for carbon steel linepipe, budget vendor costs for compressor models and fixed gaseous storage and rules of thumb and factors for construction.

Uncertainty is provided for each cost input to the total installed cost (TIC) estimate based on the aggregated uncertainty of each individual line item.

Levelised Cost Factors

The following assumptions have been made in determination of the levelised cost of the asset over its life cycle:

- The design life is 20 years.
- Inflation rate is 2.5 per cent per annum.
- Time of construction for the asset is two years.
- The salvage value of the asset is 10 per cent of CAPEX.
- The decommissioning cost is 10 per cent of CAPEX.
- A discount rate of six per cent has been applied per annum as a typical cost of capital for Australian infrastructure project.
- A profit margin of eight per cent has been applied on to the levelised cost.
- Debt to equity ratio is assumed at 0.8.

APPENDIX 8A PIPELINE COSTING BASIS

Procurement

The AS 2885.1 wall thickness calculation was used to determine the linepipe thickness required for pressure containment at various inlet pressures.

Once pipeline wall thickness required for pressure containment has been selected, a tonne per metre figure has been defined for a number of cases.

Supplier Information

Welspun, a global linepipe manufacturer, was engaged to provide up-to-date market information on dual fusion bonded epoxy (FBE) coated API 5L Grade X52 PSL2 linepipe, as well as additional information (identified within this report), such as:

- Informative discussion on cost of shipping (locally to Port Hedland, WA).
- Commercial comparison of carbon and stainless steel.
- Trends in linepipe supply costs and primary impacts.

All linepipe costs have been provided from Welspun based on the following assumptions:

- Linepipe is API 5L X52 PSL2. The quotations from Welspun were received in Q2 2021, the Q3 2021 Price index of Iron and Steel Pipe has increased by 39 per cent since this date (refer to Figure 41) – the cost adjustment has been applied to the tonneage rates quoted.
- Based on GPA experience and market rates, an additional 20 per cent cost per tonne material has been applied for natural gas cases using X65 linepipe. This is based on GPA experience and market difference in cost between X65 and “Tier 1” X52 with heightened manufacturing specifications.
- Coating is 600micron dual FBE in accordance with AS/NZS 3862 (No internal lining).
- Wall thickness is based on an informal wall thickness for pressure containment calculation.
- All linepipe supply is in triple randoms.
- Pipe manufacture method is dependent on diameter and wall thickness (either SAWL, SAWH, HFW, ERW etc.).

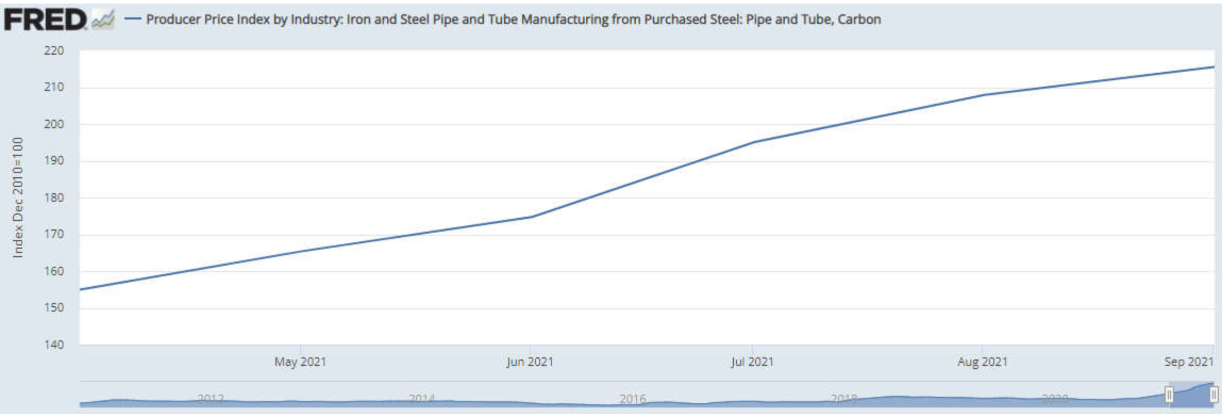

Figure 41: Federal Reserve Price Index Steel Pipe and Tube, https://fred.stlouisfed.org/series/PCU33121033121002

Manufacturing Method

Depending on the pipe diameter and wall thickness, different manufacturing methods are recommended. The manufacture process priority order is based on the Australian market preference. The manufacturing method order of priority is:

1. electric resistance welded (*ERW*)[38]
2. helical submerged arc-welding (*HSAW*)[39]
3. longitudinal submerged arc-welding (*LSAW*)[40]

Base Manufacture Material

The base material for manufacturing is dependent on the manufacture method to be used, the linepipe circumference (as the plate is formed to suit the line pipe circumference) and the wall thickness required.

The base material order of priority is:

1. hot rolled coil
2. plate from coil
3. double width plate with a centre slit

Insurance and Freight

CIF costs have been provided by Welspun for each costed case, the cost of insurance and freight (IF) has been separated in Table 25. The cost of IF is assumed to Port Hedland, WA. Generally, the cost of insurance and freight ranges from 5 to 11 per cent depending on the linepipe type.

Discharge port infrastructure will typically dictate the difficulty of unloading linepipe at arrival.

Tonnage Costing

A price has also been provided for cost, insurance and freight (CIF) to Port Hedland, WA. The cost values have been provided as today market value (June 2021) with +/-30 per cent accuracy. It is reiterated that these market values are *cost of the day* and are subject to volatile changes as reflected in the previous 12 months.

The costed cases provide a cost basis for all base material and manufacturing method combinations, with additional costs provided for extremities (smallest and largest diameter, largest wall thickness). Table 25 has been used as a basis for allocating cost to each of the outstanding cases.

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[38] ERW is line pipe manufactured from a steel coil where the width of the coil is the diameter of the pipe, the coil is cold formed into a cylinder and the longitudinal seam is welded.

[39] HSAW line pipe is manufactured from steel plate, but the plate is formed into a helix so the submerged arc weld is in a spiral.

[40] LSAW line pipe is manufactured from steel plate, formed into a cylindrical length. The formed plate is then longitudinally joined by submerge arc welding (inside and outside weld seam) to form the cylindrical pipe.

Table 25: Linepipe cost and shipping data

Variable	Tier 1 X52 Cost Range (USD/tonne)	X65 Cost Range ($USD/tonne)
Cost of Linepipe	$2,473 - $2825	$2,609 - $3,031
Insurance and Freight (IF)	$122 – $314	$157 – $376
Cost incl. Insurance and Freight (CIF)	$2649 - $3098	$2,820 – $3,358

Installation

The installation cost factor includes all civil, construction, testing, equipment, labour and bulk construction materials (not linepipe).

The installation costs will be based on remote Australian locations as a standard with a nominal amount of additional cost for an assumed amount of land features that require HDD.

Carbon steel pipeline construction rates historically have used AUD $30,000-$70,000 (i.e. $40,000 ±30 per cent) per inch diameter per kilometre for long distance pipelines (i.e. 100km) in remote locations.

This figure has been increased by five per cent to allow for the increased welding and testing requirements required for hydrogen service, and scaled appropriately for lengths shorter or longer than 100km due to economies of scale. This factor is not applied to natural gas.

The following estimate bases has been used for each length case (per inch diameter, per kilometre):

- 0-99km: AUD $70,000 ±30 per cent per inch diameter per kilometre
- 100-249km: AUD $50,000 ±30 per cent per inch diameter per kilometre
- 250-499km: AUD $40,000 ±30 per cent per inch diameter per kilometre;
- ≥500km: AUD $37,800 ±30 per cent per inch diameter per kilometre.

As a benchmark, the APLNG looping pipeline construction (a 42 inch 350km natural gas pipeline) was estimated to cost AU$31,500 per inch per kilometre in 2012, which is comparable given the relatively moderate inflation in steel prices since when comparing current prices to 2012.

The above listed construction cost factor **includes the following**:

- Early works: access track development, earthworks, laydown area construction.
- Transport of linepipe from port to lay down (assumed close proximity with easy access by road, rail or waterway).
- ROW and access clearing.
- Trenching - lower in - backfill - reinstatement.
- Loading out - stringing - bending - welding - NDT - FJC.
- Hydrotesting.
- Field service crew.
- BG and insurance.
- Management.
- HSE.

Other costs applied to this estimate include the following;

- SCADA and communications, assume at a cost of one per cent of the total pipeline cost, this is in alignment with previous cost estimates completed within GPA. (±40 per cent accuracy)
- To account for trenchless crossing, including highway, rail, major watercourses or service crossings that may require specialist construction, GPA has assumed a cost for horizontal directional drilling (HDD) or thrust boring (for short crossings) at a rate of $150,000 AUD per inch diameter, per km, at an uncertainty of ±40 per cent. It is assumed 0.5 per cent of the route requires HDD installation.
- Cathodic protection (CP), assume at a cost of two per cent of the total pipeline cost, this is in alignment with previous cost estimates completed within GPA. (±40 per cent accuracy)
- Commissioning, assume at a cost of one per cent of the pipeline base construction cost, this is in alignment with previous cost estimates completed within GPA. (±40 per cent accuracy)
- A precommissioning ILI run is required for hydrogen service to determine the maximum crack size in the pipeline and project fatigue life of the pipeline, the cost of the ILI run is assumed at $1,750,000 AUD per 100km of pipeline.

The following indirect costs associated with the pipeline construction **are not included due** to the costs being primarily driven by site location and access, which is an unknown for all cases:

- Mobilisation.
- Camp and catering.
- Ancillary (IT, PPE, flights, communications).
- Demobilisation.

The cost of MLV stations has been excluded from this cost estimate due to the difficulty with costing across a range of 16 to 46 inch, and the wide range of pressure classes. The added difficulty of non-metallic components in hydrogen service is also expected to vary the cost of pipeline main line valve facilities.

Engineering Costs

Engineering costs are considered as a cost percentage of the total pipeline procurement and installation, summarised in the table below.

Distance	EPCM Cost	Owners Costs
≤100 km	10% of Procurement and Installation	10% of Procurement and Installation
>100 km	5% of Procurement and Installation	5% of Procurement and Installation

As an overview, the cost factor includes, but may not be limited to, the following tasks:

- Prefeasibility study and initial scoping.
- FEED study.
- Initial surveys (pipeline route, tenure, geotechnical etc.).
- Detailed design.
- Risk assessment and safety studies.
- Development of construction / commissioning procedures.
- As building.

COMPRESSOR PACKAGE COSTING BASIS

Compression costing has been included for a few 0 hour and 24 hour storage cases at 500km distance.

MAN Energy Solutions (ES), has advised that its centrifugal compressor technology is market ready for high throughput hydrogen applications. This recent development improves CAPEX and OPEX by an order of magnitude compared to reciprocating units for the same flowrates and, as a rule of thumb, are available for flowrates greater than 50,000 kg/hr. Existing project examples and scenarios have been applied to estimate the costs and power consumption for cases with similar pressure differences and flowrates – the cost and power consumption for each similar case has been scaled based on the flowrate.

Where flowrates are less than 50,000 kg/hr, existing reciprocating units that have been quoted to GPA have been applied in a similar approach. It is noted the methodology is not accurate, but for the purpose of the Study and providing a +/-50 per cent estimate on a sensitivity, it is deemed satisfactory.

5.1.1.2 Technical Examples Utilised

The following compression scenarios have been applied to case numbers in order to determine overall compression cost and power consumption.

Table 26: Compressor estimate

Carrier	Compressor Supplier	Model & Motor	Case Flowrate (kg/h)	Pressure Difference (MPa)	Suction / Discharge Temperature (°C)	Total Power (MW)
Hydrogen	Man Energy Solutions	Centrifugal & EMD	115,230	8.0	30 / 90	30
Hydrogen	Burckhardt	Recip. & EMD	15,000	7.0	40 / 98	10
Natural Gas	Dresser-Rand	Recip. & EMD	77,984	5.4	40/100	3.316
Natural Gas	Solar	Recip. & EMD	233,953	6.0	30/71.8	5.554

Procurement and Shipping

From the numerous compressor vendors consulted, MAN ES provided the most viable compressor units for the large flowrate cases. The data from MAN ES has been carried forward into the cost estimate as it has provided the most applicable vendor data on compression options for several case scenarios.

The cost of compression from MAN ES includes compressor units, motors, coolers, control cabinet, oil systems and spares.

To account for the supplementary balance of plant (BoP), an additional cost of 30 per cent of the base compression cost has been added. This assumed cost factor accounts for piping, skids, filters, electrical, instrumentation, valves, and other miscellaneous items.

Cost of insurance and freight has been assumed at eight per cent of the unit cost, shipped from Europe.

Only a limited number of compression cases were able to be assessed by a vendor due to the time available for the Study and level of engagement. The largest and smallest compressor train scenario (Case 1 and Case 7 costed) have been used as a basis for costing the other project cases that were not assessed directly by a vendor for a compression scenario. Every case that has not been modelled has been linearly interpolated between MAN ES case 1 and case 7 in order to estimate the cost.

Installation

The installation cost of the compression packages, including foundation and civil works, additional steel structures and platforms for access, piping and balance of plant, and electrical and controls works have been based on a factored estimate of 1.5 times the package supply cost at an uncertainty of ±50%.

This is based on an installation factor of 2.5[41], a TIC of 2.5 time the package cost. Note the factor is only 1.5 because the procurement cost of 1.0 has been separated out and costed individually. This cost factor has been similarly used by Siemens.

Engineering

The engineering, procurement and construction management (EPCM) costs associated with a turnkey compressor solution are assumed to be 10 per cent of the total procurement and installation costs. This is in alignment with the recommended engineering cost factors used for oil and gas project by VKestimating[42]. The scope of engineering included in the cost are as follows:

- Concept work.
- Pre-FEED engineering.
- FEED engineering.
- Detailed engineering.
- Procurement services.
- Follow-on engineering.
- Site survey works.

OWNERS AND OTHER COSTS

The owners cost associated with project execution, regulatory and approvals and land acquisition etc. **has not been** factored into the final cost.

OPEX ESTIMATION BASIS

The annual operating and maintenance costs have been estimated using a factored estimate as a percentage of the CAPEX value. Different factors have been applied to the pipeline OPEX compared to compression OPEX, the factors are based on industry norms and account for differences in labour and inspection requirements. The OPEX cost basis has been summarised below in Table 27.

[41] W.E. Hand, "From Flow Sheet to Cost Estimate," Petroleum Refiner, Vol. 37, pp. 331-334, September 1958

[42] https://vkestimating.wordpress.com/2017/02/18/thumb-rules-for-engineering-costs/

Table 27: Compressor OPEX estimation basis

Variable	Value
Power Consumption – Compression	\$30USD/MWh
Operating and Maintenance – Pipeline	From 2% (Natural Gas) or 2.25% (Hydrogen gas) CAPEX Cost / Year
Operating and Maintenance – Compression	5% CAPEX Cost / Year

Power Consumption

For compressor sensitivities, a significant portion of the OPEX cost is the cost of power consumption which has been assumed at \$50USD/MWh (0.03USD/kWh) in alignment with the electrical transmission case assumptions.

Pipeline Operating and Maintenance Costs

For shorter pipelines, the operating and maintenance cost is expected to be higher per kilometre of pipeline length. Due to economies of scale, for longer length pipelines the cost per kilometre decreases.

The increased requirement for inspection and testing due to steel performance in hydrogen service and the unknowns in this area (crack growth etc.) have been considered in the factors used. OPEX factors have been adjusted to reflect increased pipeline maintenance as per ASME B31.12 (when compared to a pipeline designed to AS 2885).

Table 28: OPEX factors assumed

Pipeline Length (km)	OPEX Cost Estimate Factor (Natural Gas)	OPEX Cost Estimate Factor (H2)
≤50	3.25% CAPEX Cost / Year	3.75% CAPEX Cost / Year
≤100	2.75% CAPEX Cost / Year	3.25% CAPEX Cost / Year
≤200	2.00% CAPEX Cost / Year	2.25% CAPEX Cost / Year
≤500	1.875% CAPEX Cost / Year	2.11% CAPEX Cost / Year
500+	1.75% CAPEX Cost / Year	1.875% CAPEX Cost / Year

Compressor Station Operating and Maintenance Costs

A nominal operating and maintenance cost of **five per cent CAPEX cost / year** is assumed for compressor stations. It is assumed there is no requirement to adjust this for hydrogen service when compared to natural gas.