Integrated energy system planning: Unlocking the value and flexibility from distribution networks and electricity-hydrogen energy hubs

FINAL REPORT

Report prepared for CSIRO and Global PST Consortium

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Executive Summary

The increasing complexity of interactions within energy systems necessitates the development of innovative planning methodologies to integrate emerging technologies and infrastructure effectively. This stage of the research builds upon Topic 4, “Planning”, of the CSIRO-GPST research roadmap, focusing on scalable methodologies to support integrated energy system planning, including transmission, distribution, and hydrogen infrastructure. Key challenges addressed include the coordination of investments in distribution networks to unlock the flexibility of distributed energy resources (DERs), assessing the role of hybrid electricity-hydrogen energy hubs in enhancing system flexibility and reducing total costs, and evaluating the synergies and trade-offs between different types of infrastructure. The studies conducted within this project aim to provide system planners with methods to assess various investment drivers, mitigate risks, and evaluate reliability and resilience while maintaining cost-effectiveness in an integrated energy infrastructure development.

The core objectives and activities that have been addressed during the project include the following:

A. *Develop a methodological framework to efficiently represent the flexibility, network role, and investment needs of active distribution systems for planning purposes.*
   - Proposing and developing a methodology based on nodal operating envelopes (NOEs) to represent the operational flexibility of consumer energy resources (CERs) within distribution networks for planning tasks.
   - Conduct a proof-of-concept framework showcasing the theoretical principles and advantages of employing the proposed methodology.
   - Determining the data requirements for applying the proposed methodology from a TSO-DSO interface perspective.
   - Demonstrating the applicability of the proposed methodology through appropriate case studies to assess the investments to support the adoption of CER (e.g., network reinforcements and non-network solutions) in a planning context.

B. Assess and quantify the potential techno-economic benefits and implications of integrating the option of investing in active distribution systems within power system planning.
   - Determining the spatio-temporal scope and parameter simplifications for integrating the proposed NOE-based methodology in a whole-system expansion planning problem.

- Developing case studies to test the scalability and efficiency of the proposed methodology in the context of an integrated transmission-distribution planning problem.
- Assessing the impact and potential value provided by including active distribution systems in an integrated planning framework (e.g., to analyse the option value of CER and distribution networks versus investments at the transmission level) when considering both normal operation as well as extreme events.
- Identifying the drivers (e.g., investment costs, candidate technologies, operational conditions) making investments in active distribution systems a cost-effective option for displacing or delaying large-scale investments.

C. *Propose a comprehensive and modular framework for designing, integrating and assessing hybrid energy hubs in integrated hydrogen-electricity systems planning.*

- Defining the appropriate methodology for designing electricity-hydrogen hybrid energy hubs, identifying the constituent technologies, their interactions, and coupling with other systems (e.g., electricity network, H_2 network).
- Proposing a modular framework for the design of hybrid energy hubs that is scalable and flexible to perform transmission-level planning tasks across different geographical resolutions (e.g., regional, sub-regional or within a region) aligned with AEMO's ISP.
- Determining the data requirements for the integration of hybrid energy hubs within system planning tasks.
- Proving the applicability of the proposed methodological framework by performing illustrative case studies in test systems. The cases will include technologies embedded in hybrid energy hubs (e.g., electrolysers, VRE, BESS, H_2 storage, H_2 turbines) as investment options.

D. *Analyse the potential value of integrating H_2 transmission and hybrid energy hubs within electricity-hydrogen infrastructure planning.*

- Identifying a suitable network resolution and computational limitations for including H_2 transmission and hybrid energy hubs in an integrated electricity-hydrogen infrastructure planning framework.
- Determining the parameters for scenario studies to identify the key drivers that define the investments in H_2 technologies within integrated system planning.
- Performing case studies of integrated electricity-hydrogen system planning, comparing investment portfolios and system operation with and without H_2 pipelines and hybrid energy hubs under normal operation and resilience scenarios.
- Quantifying the techno-economic benefits of the operational flexibility provided by H_2 pipelines and hybrid energy hubs with shared connection assets that leverage diversity and the impacts of these technologies on system reliability and resilience.

Additionally, based on the previous objectives and activities, the key insights and outcomes from this project are summarised below.

A. <u>Methodology to represent the flexibility embedded in distribution systems for planning</u>

The proposed methodology is based on ***distributed decision-making,*** where transmission and distribution planning communicate through a reduced set of variables and constraints at their interface, thereby distributing the workload of integrated planning between system planners. This approach is suitable under current roles for transmission and distribution planners, requiring only a limited amount of information that is shared among stakeholders. In this project, we propose a framework for planning active distribution systems as a parametric function of DER adoption and/or coordination. This function embeds both the annual investment costs (network infrastructure) needed to support these resources, as well as the flexibility (in terms of power capacity) unlocked within distribution to the upstream system, allowing for the representation of required distribution network investments in any transmission planning framework. It consists of an investment and operational framework as illustrated in Figure 0-1.

Figure 0-1: Proposed methodology for active distribution system planning

In the first (step #1), by minimising investment and operational system costs, we build an *investment cost function* that informs the necessary investments within a distribution network to unlock a level of DER adoption over an array of potential DER capacities[1], which could relate to planning scenarios, coordination of resources, available flexibility, etc. ***Each point in an investment cost function describes a pair of infrastructure (network and non-network solution) investment cost (y-axis) and accessible DER capacity (x-axis).*** Secondly (step #2), we iterate over each discrete pair of network investments and DER capacity that composes the investment cost function. For each pair, an optimal power flow (OPF) is performed for each representative period (e.g., days, weeks, etc.) considering inter-temporal constraints such as state of charge from storage, as well as time-varying power limits for DER. Based on this OPF, we explore the flexibility available from DER by maximising the exports and imports that a given distribution system can sustain given investments (e.g., result from step #1) and network constraints (e.g., voltage and thermal limits). Thus, this step allows for capturing the degree to which aggregated DER can deviate their power towards imports and exports in each time-step, also referred to as NOEs . Then, as an output of this process, an equivalent model can be found, which is characterised by aggregated generation, load, and storage components (i.e., NOEs for each of these components).

It is worth mentioning that the OPF in step #2 is needed despite that investments and operational costs are minimised when planning ADNs (step #1). This is because planning considers representative periods as it is a more complex problem, nevertheless the portfolio of investments determined will be valid for any operational state that the network goes through. In this context, OPFs are needed to explore the ADNs capabilities for operational states that were not directly represented within the planning framework.

In summary, this methodology provides two steps that DNSPs could follow to produce planning and operational information regarding future scenarios (e.g., CER coordination, DER adoption) while using their tools, and communicate it to the central planner, such as AEMO, allowing for a more informed integrated decision-making process.

Case studies demonstrate the importance of proactive distribution network planning when integrating DER, and how the proposed approach could greatly benefit the adoption of these resources. Figure 0-2 compares investment cost functions associated with the connection of distributed solar, evenly distributed across the system (each bus has the same DER capacity), and when the optimisation freely decides what capacity to connect in each bus to achieve the desired adoption in each DER level of the parameterisation. When jointly planning the

[1] Also referred to as parametrisation in this report

network with DER integration, *the network’s hosting capacity can be fully utilised*, leveraging larger capacities in zones with higher demand and near the top of the feeder. In contrast, additional investments in storage and reactive compensation are required if DER capacity is evenly distributed. Thus, this methodology provides a better understanding of the synergies within distribution networks, encompassing drivers like technologies, demand profiles, and hosting capacity, further reducing total investment costs when integrating DER over time.

Figure 0-2: Parametric investment cost function when connecting additional DER, solar and wind units optimally allocated

The importance of curtailment, meaning the ability to actively reduce the output from generation-based DER to deal with limited network capacity, was analysed through parametric investment cost functions for levels of DER curtailment of 0%, 15%, and 30%. This was modelled as a constraint that limits curtailment to these levels to incentivise investments that maximise the exports of the network. This means the network is able to inject up to 100%, 85%, and 70% of the available DER capacity while in operational terms, each scenario can curtail energy for the purposes of maximising imports. These results were compared with a scenario where curtailment is penalised with the customer export curtailment value (CECV) as seen in Figure 0-3.

Figure 0-3: Parametric investment cost function when connecting additional DER, solar and wind units optimally allocated

It is also concluded that proactively planning distribution networks, including non-network solutions, and the integration of distributed generation, allows for capturing the best connection schedule, solving local problems, and enhancing hosting capacity with more granular investments. Thus, an enhanced active management of the distribution network (e.g., by enabling controlled DER curtailment) could allow for greater levels of DER adoption before network reinforcements are required. Furthermore, although CECV represents a good proxy for the purpose of planning distribution networks, an optimal level of curtailment could be determined when coordinating transmission and distribution planning. Thus, it might be cost-effective from a whole system perspective to either have the possibility of fully using DER (maximum exports, no curtailment) or consider some level of curtailment to delay investments.

Remarkably, NOEs allow for the characterisation of the flexibility unlocked within investment cost functions. This is illustrated in Figure 0-4 for each curtailment scenario, considering a single snapshot of peak of DER generation, for levels of DER adoption of 12 MW, 18 MW and 26 MW. Here, the maximum active power flexibility is reached when the network is planned to operate with no curtailment (e.g., network is enhanced through reinforcements to fully export DER), while in the other cases, NOEs increase on the reactive power plane due to active management of the network, enhancing its hosting capacity without investing in network reinforcements.

Nevertheless, as more DER are integrated, NOEs increase in both active and reactive power flexibility due to portfolios of investments that combine network and non-network solutions (e.g., distributed storage, reactive compensation). This means that as more DER capacity is integrated in the system, DNSPs will have to shift towards managing the distribution network more actively and adopt different solutions to facilitate DER integration and unlock flexibility. In turn, with the proposed methodology, this information can be communicated to the transmission planning process to fully understand the most cost-effective way of developing a more integrated system.

a) 12 MW of DER adoption

b) 18 MW of DER adoption

c) 26 MW of DER adoption

Figure 0-4: NOEs during solar peak associated to each parametric cost function of curtailment scenarios.

The impact of CER coordination was assessed by planning subtransmission networks CBTS, GNTS-MBTS, TSTS, TTS, and ERTS. These are subtransmission networks of 66 kV in the State of Victoria, within the Melbourne region, which were facilitated by AusNet. Investment cost functions were computed for 0%, 25%, 50%, and 100% of CER coordination, accounting for the capital cost of coordination infrastructure. These results are shown in Figure 0-5 considering projections of CER for the years 2040 and 2050, respectively. Here, CER coordination has a huge impact on how subtransmission networks are planned. When comparing the 0% and 100% CER coordination, total annual investments in infrastructure are reduced on average 50% for CBTS, 72% for GNTS-MBTS, 90% for TSTS, 48% for TTS, and 45% for ERTS, suggesting that rural networks tend to see more benefits from CER coordination (e.g., longer networks that require more compensation, meaning more investments). Such reductions come from the added flexibility from CER coordination, solving several local problems that defer initial investments. These benefits will depend on the characteristics of the network (e.g., peak load, composition, topology, etc.) and its hosting capacity.

Figure 0-5: Investment cost functions for subtransmission networks

These aspects are part of the essence of integrated planning frameworks, where trade-offs between transmission and distribution investments are captured. Based on this, DNPSs could build scenarios based on DER integration and the level of curtailment where network reinforcements, and perhaps additional infrastructure such as reactive compensation, are displaced until further levels of DER adoption.

Then, to estimate the aggregated investment cost for the State of Victoria under different levels of CER coordination (0%, 25%, 50%, and 100%), the cost functions from these subtransmission networks were combined proportionally, i.e., based on a network composition of approximately 85% urban (CBTS, ERTS, TTS) and 15% rural (GNTS-MBTS, TSTS), as supported by prior studies. The resulting investment cost curve, shown in Figure 0-6, demonstrates how DNSPs could inform AEMO to enhance alignment between distribution and transmission planning. This parametric approach is flexible for any DER adoption scenario and, in this case, highlights that coordinated CER integration in Victoria could yield investment cost savings of around 50% by 2040 and 2050.

Figure 0-6: Victoria's aggregated parametric investment cost function for levels of CER coordination

B. Assessment of the integration of transmission and distribution in system planning

This equivalent representation of ADNs planning can be integrated into any transmission planning framework as a set of linear constraints (for details see Appendix C) and thus, the central planner can manage aggregated DER based on time-varying limits that capture distribution network's investments and limits (e.g., thermal and volage). For this project, the integration of the proposed methodology and its applicability within transmission planning frameworks was tested through *"representative networks"* based on real data from the State of Victoria.

First, case studies using the sub-transmission network CBTS to represent the distribution side of sub-regions within the ISP revealed the applicability of the methodology. To do this, we proportionally allocated the expected CER, demand, and the associated traces, based on the current state of the selected representative Victorian network (e.g., peak demand and rooftop PV capacity). From this, we analysed the impact of CER coordination (e.g., curtailment of rooftop PV, operation of distributed storage in the form of a virtual power plant, and demand response schemes) in the planning of distribution systems, and their inclusion in this transmission planning problem.

It was found that investment costs in distribution systems can be hugely reduced, even when only coordinating 50% CER. Most of these benefits come from the operation of distributed storage expected in each sub-region (optimal decision is to first coordinate storage), which serves as the most important source of flexibility to alleviate constraints within distribution systems and reduce curtailment. Moreover, as the level of coordination is increased, additional flexibility is gained in the form of demand response. Nevertheless, these do not change the investment costs when planning the network.

In a first instance where only Sydney, Newcastle and Wollongong (SNW), South and Central New South Wales (SNSW and CNSW) regions were represented in a reduced 6-bus model of the NEM (4 subregions of NSW plus aggregated north and south of the NEM), CER coordination yields **a 26% total cost reduction** in comparison to a case with no coordination. This is primarily due to the **deferral of two transmission augmentation options, which account for 3.4 GW**, as well as the reduction in distribution network investment costs resulting from CER coordination. At the same time, **curtailment is also reduced by 7%.**

To show the scalability of this methodology, the same analysis was extended to include distribution representations of Victoria, Tasmania, and Central South Australia. From this case study, coordinating CER results in a **28%** reduction in total costs compared to the case with 0% CER coordination, achieved by avoiding three **transmission projects** that would represent **6.4 GW and reducing distribution investment costs.** These are promising results, but benefits should not be taken as an accurate assessment because the limitations of the distribution side are not properly captured in each sub-region, but rather as how this methodology is integrated to the whole NEM model.

This increase in flexibility allows for a more active management of distribution networks (modelled with an equivalent model), which translates into leveraging existing and expected resources more optimally. As seen in Figure 0-7 coordinating CER, particularly storage, allows for a reduction of peak demand and an increase of net-load during peak hours of solar generation, which in turn allows for reductions in DER curtailment.

a) Equivalent model representing the subregion SNW *b) Equivalent model representing the subregion VIC*

Figure 0-7: Power exchange between SNW, and VIC, with the NEM, for one representative week, compared to a passive distribution network

The inclusion of additional DER was assessed through additional distributed storage of 2 hours of duration. Thus, the parametrisation in this case covers 100% of coordinated CER, e.g., curtailment, VPPs, and demand response, and two additional levels of distributed storage (e.g., additional DER). From this case study, no additional distributed storage was required. This result suggests that efforts should be made towards achieving 100% CER coordination from the expected adoption in the step-change scenario of the ISP 2024. This is due to the large-scale storage capacity expected in the NEM, reaching 21.4 GW for the step-change scenario, including projects such as Snowy 2.0, and Borumba.

In this sense, additional distributed storage could be valuable if deciding on the total amount of storage needed (no existing nor expected storage from ISP). In this case, there would an optimal mix between large- and small-scale. This additional distributed storage could also open possibilities for connecting additional distributed generation. Nevertheless, such a comparison would be unfair if the trade-off with large-scale renewables is not considered.

Furthermore, high-impact, low probability (HILP) events were also analysed. Extreme events are incorporated as distinct representative periods within the year of analysis, weighted by their likelihood of occurrence. Input data is modified to reflect conditions such as increased demand, reduced renewable generation, or alterations in the system's architecture due to different infrastructure outages.

For this case study, we analyse the loss of one interconnector between CNSW and SNW with capacity 4.7 GW. Although the HILP event, the integrated model still optimally determines that no additional distributed storage is needed, and that CER coordination is the optimal path to develop the system. As CER coordination can make consumption patterns more efficient, it allows for deferring transmission expansion in 3.4 GW. Moreover, if we consider large-scale storage as an investment option, 300 MW in SNW are part of the portfolio of investments, further reducing operational costs.

It is worth mentioning that one of the more relevant results in Stage 3 of Topic 4 was that incorporating extreme events into the planning problem reveals the need for anticipatory reinforcements in the transmission network, and the value of CER coordination when mitigating the impact during these extreme periods. Nevertheless, this aspect is not explored because we focused on the methodological integration of distribution networks planning. Further work could extend this into coupling parametric cost functions for multiple decision nodes so that lead-time of investment alternatives such as transmission or distribution network augmentations is incorporated, properly assessing transmission augmentations.

Additional case studies were performed representing the State of Victoria with the parametric cost functions built for subtransmission networks. For the year 2040, there are no changes in the total transmission augmentations, as both 0% CER coordination and 100% coordination result in additional 9.5 GW of transmission capacity. Nevertheless, there is a reduction in annual investment and operational costs of 7.8%, and total curtailment (transmission and distribution assets) in 8%. The same analysis was made for year 2050, where the reduction in total costs is 20%. In particular, investment costs are reduced by 1.5% due to the deferral of 1.2 GW of transmission augmentations and benefits from distribution network planning, while the core of the benefits come from operational costs, that are reduced in 20.2%.

This can be seen for the State of Victoria in Figure 0-8. The optimal case for CER coordination, i.e., storage and demand-response, can make consumption pattern more efficient, reducing the peak demand but also increasing the load during peak solar generation while reducing curtailment in 4.5% when the 100% of CER coordination.

a) Reference year 2040

b) Reference year 2050

Figure 0-8: Operation of State of Victoria, represented by the equivalent model

Finally, to achieve better assessments in terms of cost reductions, it is necessary to understand the limitations and investments required within distribution networks across all levels, including LV, MV, and HV, as well as across all subregions. This is truly important as the flexibility from CER, such as EVs, domestic hot water (DHW) and distributed batteries might be overestimated. Such an overestimation can occur because some resources could be constrained due to limitations within MV-LV networks, unless proper investments are made. Additionally, varying consumer preferences to participate in the provision of services can also impact the total availability of CER capacity.

In this sense, a trade-off will arise between distribution investments and the provision of local services by CER. This balance will depend heavily on the objective function of the distribution planning approach. For instance, at the extreme, DNSPs could present future paths that fully exploit CER capacity, i.e., maximising flexibility to be coordinated upstream. Another approach would be to plan distribution networks by minimising costs, where CER coordination would help reducing investments for DNSPs, but the amount of flexibility that these resources could provide upstream would be constrained. Nevertheless, benefits would come with more efficient consumption patterns in a decentralised manner.

C. <u>Development of a modular framework to design electricity-hydrogen energy hubs</u>

As illustrated in Figure 0-9, the proposed modular framework for hybrid energy hubs optimises the design of electricity-hydrogen hybrid systems by minimising the capacity of connection assets through integrated investment coupling. In traditional bus-level (independent investment) planning, each investment component, such as wind turbines, solar PV, batteries, and electrolysers, has its own dedicated HV substation. These substations often include MV/HV transformers, switchyard, reactive plant, and other associated equipment, along with a dedicated feeder to connect to the grid.

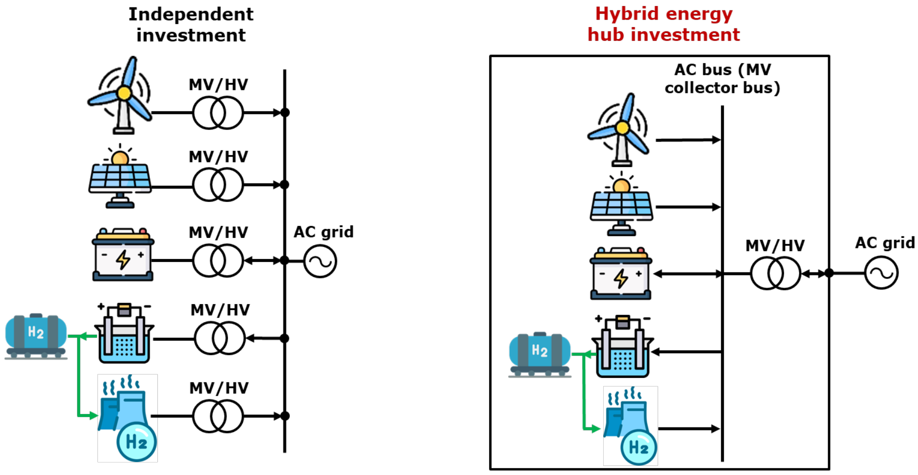


Figure 0-9: Illustrative comparison of bus-level (left) and hub-level (right) investment approach.

In contrast, the hub-level planning approach integrates these generation, storage, and H_2 production components, enabling energy to be collected at a shared MV bus within the hub. Instead of using multiple individual MV/HV transformers in separate HV substations, the hybrid energy hub enables a MV/HV step-up/down process through shared connection assets to match the voltage for grid connection. This leverages the diversity across different technologies within a hub, reducing the total capacity of connection assets. As a result, the hub-level planning approach is numerically demonstrated to decrease investment costs.

As shown in Figure 0-10, the proposed modelling framework captures both the build cost and connection cost for each technology option, enabling a modular approach to investment planning. Each technology is modelled with two distinct cost components: build and connection components. These include the capital and installation costs of the main equipment and connection assets, respectively. This separation allows the model to assess the synergies and economies of scale achieved when co-locating components within a hybrid energy hub. To optimise the overall system costs, the model has the flexibility to choose between investing in components individually at the bus level or co-locating them within a hub. Additionally, the model aggregates the power flow from both hub-level and bus-level components at each REZ node. When the total power flow between the REZ and the existing grid exceeds the REZ transmission capacity stipulated in AEMO's 2024 ISP, additional REZ network expansion costs are applied. This integrated approach captures the combined impacts of generation, connection, and transmission within REZs, enabling a more robust and cost-aware investment framework that guides decisions on co-location, independent investments, and REZ network reinforcement.

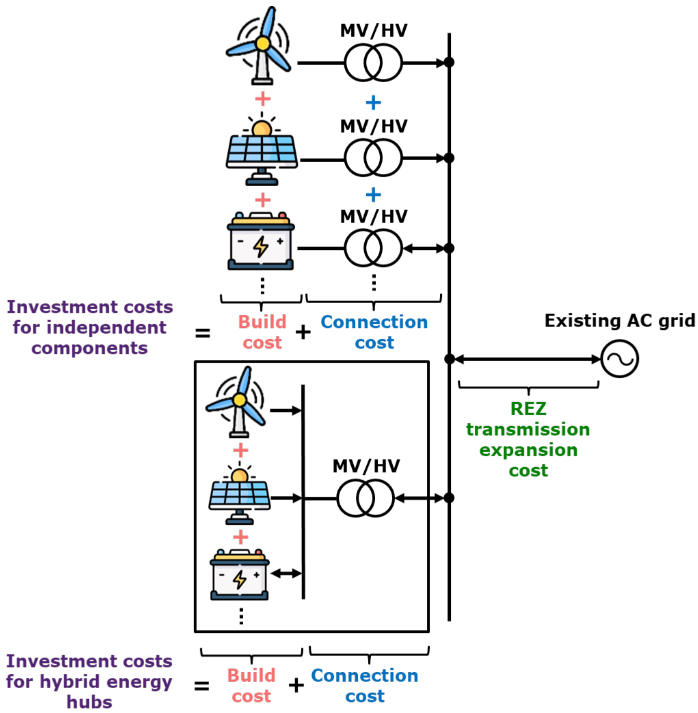


Figure 0-10: Cost representation for bus-level independent investment, hub-level integrated investment, and REZ transmission expansion.

Furthermore, the model for integrated electricity-hydrogen hybrid energy hubs is then incorporated into a general integrated electricity-H_2 transmission planning framework. As illustrated in Figure 0-11, the model determines the components installed within each hub, leading to the formation of three different hub types based on their optimised configuration and role within the energy system. For instance, if only renewable generation and battery storage are selected, the hub acts as a *renewables hub*. If only H_2-related technologies such as electrolysers, H_2 storage, and H_2 turbines are included, the hub functions as an *H_2 hub*. When both renewable generation, storage and H_2 infrastructure are co-located, the hub operates as a *renewables-H_2 hub*. The resulting hub types then influence how they are interconnected with each other and with the rest of the system, whether through electricity transmission lines, H_2 pipelines, or both. This co-optimisation of hub configuration and transmission investments enables the model to identify the most cost-effective and flexible energy transport methods that optimally support electricity and H_2 demand under different planning scenarios.

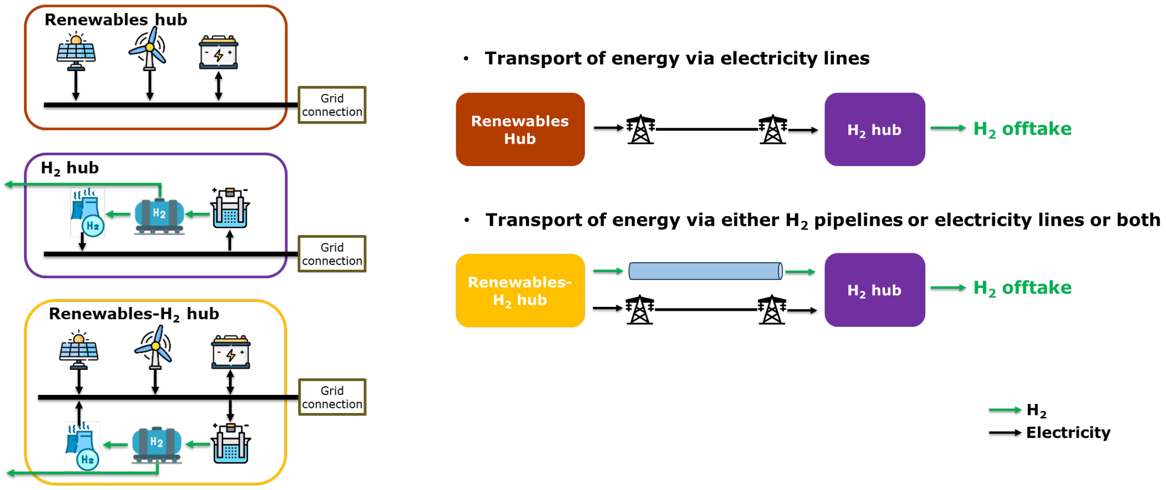


Figure 0-11: Three types of energy hubs (left) and possible interconnection of energy hubs (right).

An illustrative example of integrated planning of energy hubs and transmission is shown in Figure 0-12. If only electricity transmission is considered, hubs in remote REZs could operate as renewables hubs, while H_2 production would be located at the domestic or export H_2 demand site, either in H_2 hubs or renewables-H_2 hubs. On the other hand, if H_2 pipelines are included as an infrastructure option, H_2 production could instead be located within renewables-H_2 hubs in REZs, enabling direct transport of H_2 to demand sites via H_2 pipelines. By jointly planning hybrid energy hubs with electricity and H_2 transmission, the system benefits from cost reduction and greater flexibility in energy generation, H_2 production and energy transport.

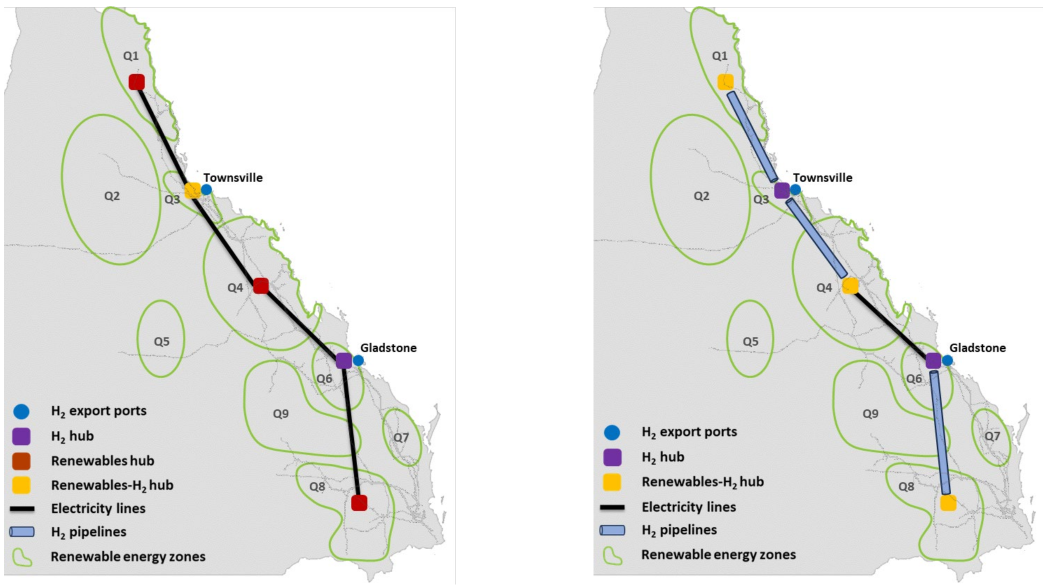


Figure 0-12: Illustrative examples of integrated planning of energy hubs and transmission when only considering electricity transmission (left) or both electricity and H_2 transmission (right).

However, it is important to mention that since the exact locations of VRE resources within REZs are uncertain, they may not be geographically co-located. In such cases, coupling components within an energy hub may not be realistic, and the system may require additional infrastructure, reducing the potential savings.

D. Techno-economic assessment of H_2 transmission and hybrid hubs integration

The system topology, potential transmission corridors for both electricity lines and H_2 pipelines, REZs, and H_2 export locations are illustrated in Figure 0-13. In this work, H_2 is assumed to be exported from export ports in Queensland, South Australia, and Tasmania in the studied year of 2035, in line with the assumption in AEMO's 2024 ISP. The high-voltage electricity transmission networks in these three regions are modelled with greater resolution compared to the ISP to provide a more detailed technoeconomic assessment of H2 transmission and hybrid hubs integration. Additionally, interconnectors linking subregions are also considered. A hypothetical H_2 network with multiple H_2 junctions and pipeline corridors is designed for H_2 transport within these three regions. VRE and BESS investment options are considered in all REZs, while H_2-related investment options are considered at all H_2 nodes coupled with electricity buses. Two sets of case studies are conducted under the *Step Change* and the *Green Energy Exports* scenarios for 2035: one under "Normal operation" which uses the VRE traces for year 2035 in the ISP scenarios directly (Case 1-Base, 2-WithPipe, 3-Hubs) and another for resilience studies, including a VRE drought event (Case 1R-Base, 2R-WithPipe, 3R-Hubs). Case 1-Base and Case 1R-Base include electricity transmission lines and bus-level independent investments; Case 2-WithPipe and Case 2R-WithPipe additionally incorporate H_2 pipeline investments; and Case 3-Hubs and Case 3R-Hubs further include hybrid energy hub investments with optimised shared connection assets. The optimal investment results are shown in Figure 0-14 and summarised in Table 0-1.

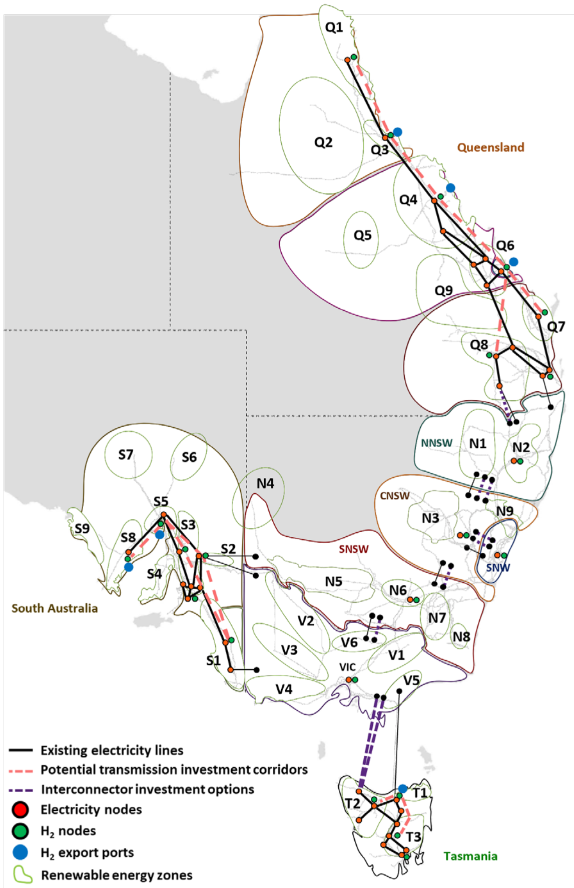
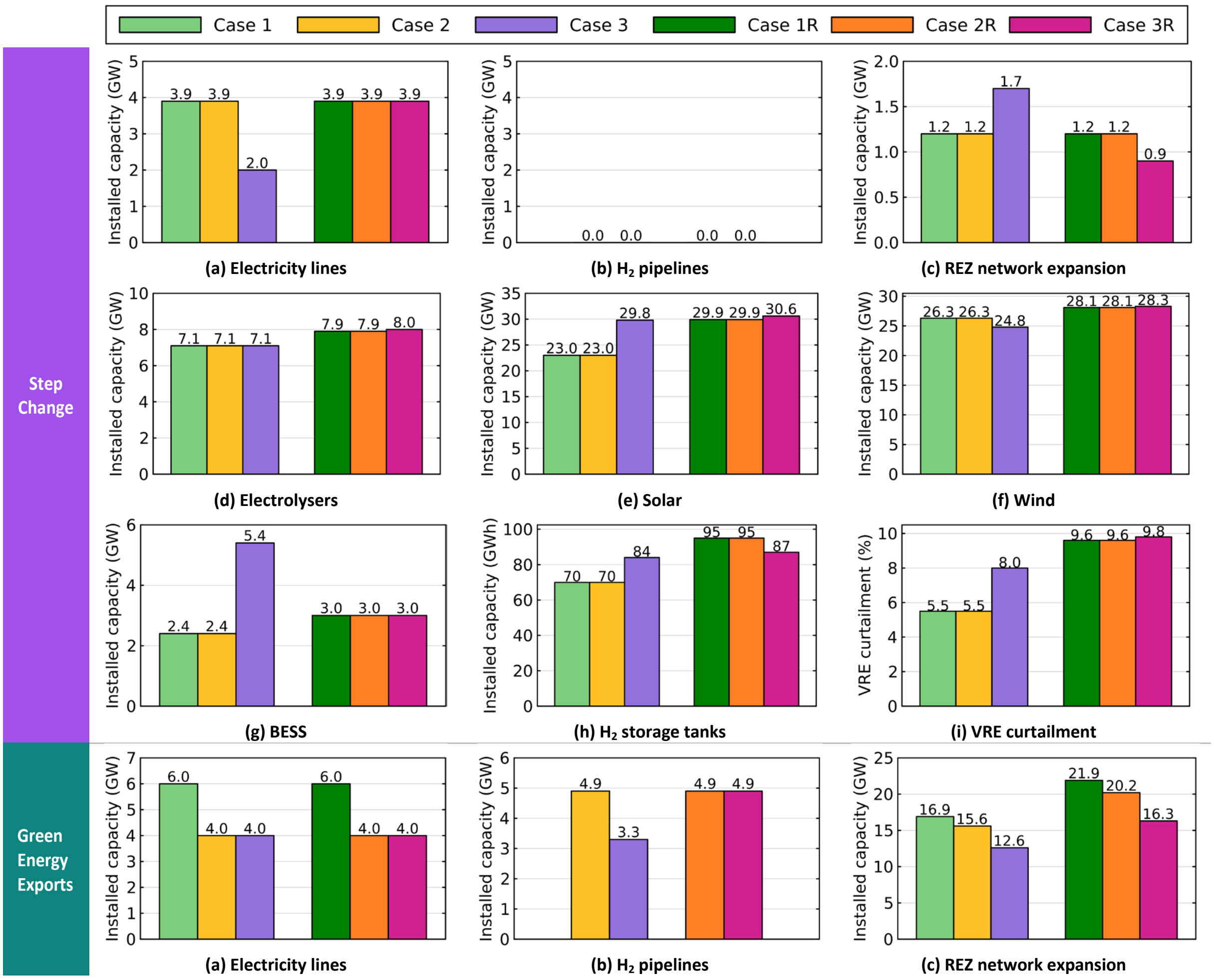


Figure 0-13: Geographical illustration of system topology, transmission, REZs, and H2 export locations.

<u>*Normal operation studies*</u>

The inclusion of H_2 pipelines in integrated electricity-H_2 systems planning can enhance system flexibility and displace electricity transmission under large-scale H_2 demand scenarios. As shown in Figure 0-14, under the Step Change scenario, the model does not invest in H_2 pipelines, as domestic and export H_2 demands are sufficiently met by the local electrolysis, supported by electricity transmission. On the other hand, under the Green Energy Exports scenario, where large-scale H_2 exports are envisioned, H_2 pipelines are selected as more cost-effective alternatives to electricity transmission lines. This displaces HVAC line investments, reduces REZ network expansion, and lowers the need for additional electrolysers and VRE generation at export sites. In addition to transporting energy, H_2 pipelines also provide storage capability, which can displace stationary H_2 storage and improve utilisation of VRE, leading to reduction in VRE curtailment. Overall, under the Green Energy Exports scenario, Case 2-WithPipe achieves **1.6%** reduction in total system costs, compared to Case 1-Base.

The inclusion of hybrid energy hubs with shared connection assets can leverage diversity across different technologies within a hub and displace electricity-hydrogen transmission infrastructure. Integrating H_2 electrolysis and storage with renewable generation within a hub enables more efficient use of local VRE for H_2 production and electricity export to the grids, which can reduce the need for additional electricity or H_2 transmission infrastructure and lower total system costs. As shown in Figure 0-14, under the Step Change scenario, Case 3-Hubs displaces total capacity of electricity transmission and REZ network expansion investments, compared to Case 2-WithPipe. On the other hand, under the Green Energy Exports scenario, the additional need for H_2 transmission and REZ network expansion are reduced when hybrid energy hub investment options are included in Case 3-Hubs, compared to Case 2-WithPipe. As a result, Table 0-2 shows that investments in energy hubs are dominant across most REZs, compared to independent component investments at the bus level. Overall, a **2.0%** and **5.7%** decrease in total system costs may be achieved in Case 3-Hubs under the Step Change and the Green Energy Exports scenarios, respectively, compared to Case 2-WithPipe.



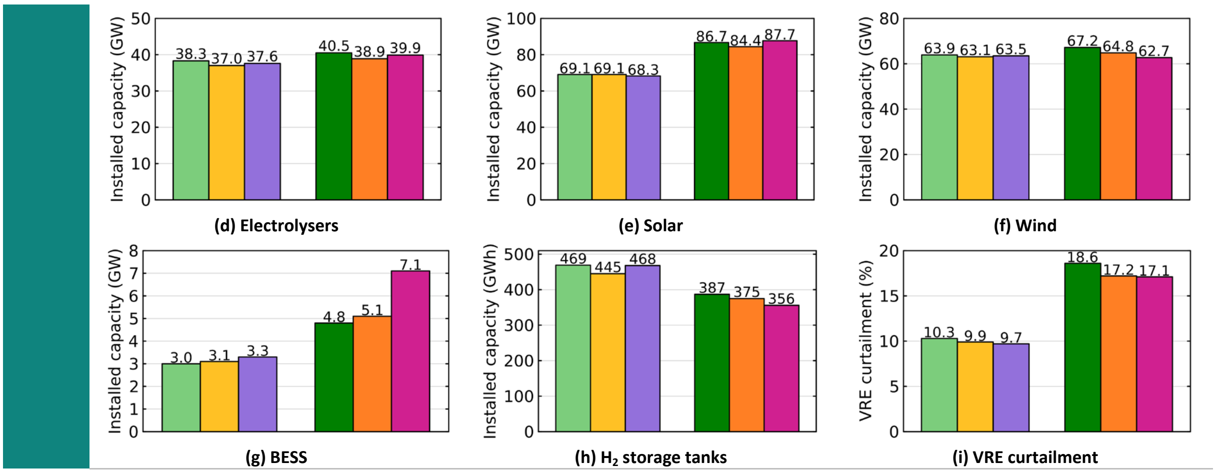


Figure 0-14: Comparison of optimal investment results (a)-(h) and VRE curtailment (i) under both scenarios under the Normal operation and the Resilience case studies.

Table 0-1: Summary of case study results.

Scenario	Normal operation studies		Resilience studies		
	Case 2-WithPipe	**Case 3-Hubs**	**Case 1R-Base**	**Case 2R-WithPipe**	**Case 3R-Hubs**
Step Change (2035)	• No **H_2 pipelines** are installed, and results are the same compared to Case 1-Base.	• Compared to Case 2-WithPipe, incorporating **hybrid energy hubs with optimised shared connection assets** displaces **electricity lines** and saves **2.0%** in total system costs. • **H_2 pipelines** are not installed.	• Compared to Case 1-Base, total system costs increase by **3.3%**.	• No **H_2 pipelines** are installed, and results are the same compared to Case 1R-Base. • Compared to Case 2-WithPipe, the total system costs increase by **3.3%**.	• Compared to Case 2R-WithPipe, incorporating **hybrid energy hubs with optimised shared connection assets** reduces total system costs by **2.2%**. • Compared to Case 3-Hubs, an **additional electricity line** is installed, and total system costs increase by **3.1%**. • **H_2 pipelines** are not installed.
Green Energy Exports (2035)	• Compared to Case 1-Base, incorporating **H_2 pipelines displaces electricity lines** and **saves 1.6% in total system costs**.	• Compared to Case 2-WithPipe, incorporating **hybrid energy hubs with optimised shared connection assets** displaces **H_2 pipelines** and saves **5.7%** in total system costs.	• Compared to Case 1-Base, total system costs increase by **6.7%**.	• Compared to Case 1-Base, incorporating **H_2 pipelines** reduces total system costs by **1.6%**. • Compared to Case 2-WithPipe, total system costs increase by **5.9%**.	• Compared to Case 2R-WithPipe, incorporating **hybrid energy hubs with optimised shared connection assets** reduces total system costs by **5.4%**. • Compared to Case 3-Hubs, an **additional H_2 pipeline** is installed, and total system costs increase by **5.9%**.

Table 0-2: Percentage of bus-level and hub-level investments in REZs in Case 3-Hubs and Case 3R-Hubs under both scenarios under the Normal operation and the Resilience case studies.

Scenario	Investments in REZs	Normal operation studies		Resilience studies	
		At hub-level (%)	At bus-level (%)	At hub-level (%)	At bus-level (%)
Step Change	Solar	94.3	5.7	85.9	14.1
	Wind	95.4	4.6	91.7	8.3
	BESS	96.1	3.9	95.8	4.2
	Electrolyser	97.3	2.7	94.7	5.3
Green Energy Exports	Solar	96.7	3.3	97.4	2.6
	Wind	94.6	5.4	97.5	2.5
	BESS	100	0	100	0
	Electrolyser	99.7	0.3	98.7	1.3

Resilience studies

Total system costs increase across all resilience cases compared to the normal operation cases, due to the additional infrastructure investments required to ensure supply reliability during VRE drought events. The range of cost increases is between **3.1** and **3.3%** under the Step Change scenario and between **5.9** and **6.7%** under the Green Energy Exports scenario.

Under the Green Energy Exports scenario, H_2 pipelines maintain resilience at cheaper costs. Compared to Case 1R-Base, Case 2R-WithPipe maintains reliable energy supply at up to **2.3%** lower total system costs, while also reducing VRE curtailment and displacing electricity line and storage investments as detailed in Figure 0-14. Notably, one additional H_2 pipeline is installed in Case 3R-Hubs compared to Case 3-Hubs, highlighting the role of H_2 pipelines in providing cheaper storage during VRE drought periods.

Under both scenarios, hybrid energy hubs also play an important role in maintaining system resilience at lower costs. Compared to Case 2R-WithPipe, the inclusion of hybrid energy hubs in Case 3R-Hubs enables more cost-effective use of available VRE for electricity generation and H_2 production during VRE droughts. Overall, compared to Case 2R-WithPipe, Case 3R-Hubs achieves a reduction in total system costs of **2.2%** under the Step Change scenario and of **5.4%** under the Green Energy Exports scenario, while maintaining reliable energy supply. As a result, hybrid energy hub investments are dominant across most REZs, compared to independent component investments at the bus, as outlined in Table 0-2.

Acronyms

AC	alternating current
AEMO	Australia Energy Market Operator
BESS	battery energy storage systems
CER	consumer energy resources
DC	direct current
DER	distributed energy resource
DSM	demand-side management
HILP	high impact and low probability
HVAC	high voltage alternating current
HVDC	high-voltage direct current
ISO	independent system operator
ISP	integrated system plan
MILP	mixed-integer linear programming
NEM	National Electricity Market
PEM	proton exchange membrane
PV	photovoltaic
REZ	renewable energy zones
TEP	transmission expansion problem
UC	unit commitment
VRE	variable renewable energy

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1 Introduction

1.1 Context

The planning of energy systems is facing significant challenges due to a manifold of new interactions and the increasing diversity of new technologies connected to the system. On the one hand, this trend is highlighted by the fast uptake of renewable energy towards the decarbonisation of the energy sector and the increasing active participation of customers through different controllable assets in distribution networks (e.g., electric vehicles, community batteries). These assets are vital for linking the supply and demand sides, and for unlocking operational flexibility provided by distributed energy resources (DER) through adequate investments. On the other hand, the emerging production of green hydrogen as an alternative to traditional carbon-based energy carriers opens new value streams and business opportunities, such as hybrid electricity-hydrogen energy hubs. These hubs can support the development of the hydrogen industry in Australia and leverage economies of scale to produce hydrogen for local consumption and export. Additionally, these could enhance the operational flexibility of the system through its capacity to transform and store energy vectors (e.g., hydrogen and electricity) at different duration timescales.

However, current planning approaches fall short in efficiently assessing the coordination between transmission and distribution systems, as well as the integrated planning of hybrid energy hubs and electricity-hydrogen transmission infrastructure.

In terms of considerations about distribution systems, current approaches often struggle with the applicability of integrated transmission-distribution planning in real-world settings. Centralised and multi-level approaches rely on increasing the scale of optimisation problems by including additional variables and constraints that fully model the limitations of the distribution side, reducing computational requirements by neglecting key aspects such as operational granularity, long-term planning horizons. More importantly these methods assume full data exchange between system planners which neglects their current roles [1]. Nevertheless, iterative and decoupled approaches improve feasibility and computational efficiency by limiting information exchange to a small set of variables and/or constraints, decentralising decision-making and parallel computing [2]. The latter approaches have yet to be explored further into real-world applications but show promising adaptability to current policy and planning frameworks.

Current energy system planning approaches typically focus on individual components at the bus level, treating technologies like wind, solar, electrolysers, and storage as independent investments with their own dedicated connection assets. This leads to redundant infrastructure, increased capital costs, and lower energy efficiency due to voltage step-up/down in multiple connection assets. Moreover, most existing studies on energy hub design do not explicitly separate shared connection assets from primary equipment or account for associated costs. As a result, these planning models often resemble traditional bus-level investments, despite being described as hub-level approaches, limiting their ability to accurately quantify the benefits of hub-level coordination. Furthermore, the lack of integrated planning of energy hubs with electricity-hydrogen transmission infrastructure overlooks valuable opportunities to reduce need for long-distance transmission and enhance system resilience, particularly during extreme events like VRE droughts.

Hence, system planners require new methodologies that allow performing real-world integrated energy system planning while capturing the synergies and trade-offs between infrastructure at different scales. Moreover, such methodologies must be capable of providing key insights and informing as to what extent investments in distribution systems or in infrastructure to produce green hydrogen could delay, displace, or compete with investments at the transmission level, while striking a balance between cost-effectiveness, system reliability, security, and resilience, as well as computational efforts.

Against this background, and in line with the recommendations outlined in the final report for Stage 3-Topic 4 of the CSIRO-GPST roadmap, the 2021 research plan, and AEMO's 2024 ISP, this research project aims at developing scalable (i.e., computationally efficient) methodologies capable of informing planners about the required developments to successfully perform an integrated energy system infrastructure planning (transmission, distribution, hydrogen). Building upon these developments, this project studies how it is possible to represent distribution networks to explicitly and efficiently include them in planning; how investments in distribution networks would unlock the clean energy and flexibility of DER, potentially displacing or deferring other investments (e.g., transmission-level lines or storage); how planners can represent hybrid energy hubs; what are the drivers for investing in such hubs; and to determine the value of different types of energy storage within integrated planning. In doing so, the University of Melbourne (UoM) will collaborate closely with AEMO, and potentially other stakeholders, to receive relevant inputs, feedback, and to jointly define specific sets of pertinent case studies.

The primary outcomes from the project illustrate how the planning of active distribution networks can be integrated within transmission planning frameworks such as the ISP, providing clear steps from which DNSPs can produce this information with their own tools, and communicate it to system planners in a decentralised fashion aligned with current regulation and roles. The integration of hybrid energy hubs and hydrogen pipelines into system planning enhances coordination between electricity and hydrogen supply, enabling decentralised, cost-effective investments. This approach supports flexible, resilient network development and offers a modular framework for planners to co-optimise generation, storage, and transmission across multiple energy carriers. In this regard, this project can support and inform the development of planning approaches used by AEMO and other system operators (e.g., National Grid ESO in the UK) into an efficient integration of distribution networks and hydrogen infrastructure, guiding and contributing to the enhancements in other jurisdictions, particularly within the context of the GPST consortium's international activities and outreach.

1.2 Aims and objectives

This project proposes methodological approaches geared towards representing the planning of active distribution systems and hybrid energy hubs with adequate detail to efficiently integrate them within planning frameworks, assessing drivers, limitations, potential benefits, and techno-economic implications of this integration at a whole-system level. As part of the project, proofs of concept and validations with network models are conducted to demonstrate the principles, applicability, and scalability of the proposed methodologies. The project tasks and their alignment with the *planning* research roadmap are as follows:

A. Develop a methodological framework to efficiently represent the flexibility, network role, and investment needs of active distribution systems for planning purposes (Planning roadmap - Research projects R4S3P1, R5S2P1).
B. Assess and quantify the potential techno-economic benefits and implications of integrating the option of investing in active distribution systems within power system planning (Planning roadmap - Research project R5S1P1).
C. Propose a comprehensive and modular framework for integrating, designing, and assessing hybrid energy hubs in planning integrated hydrogen-electricity systems (Planning roadmap - Research project R5S3P1).
D. Analyse the potential value and development drivers of integrating hybrid energy hubs within electricity-hydrogen infrastructure planning (Planning roadmap - Research project R3S3P3).

In the context of the CSIRO-GPST research roadmap [3], Figure 1-1 depicts the expected completion status of each relevant research activity by the end of this stage of the research roadmap.

TASK	PROGRAMME	STREAM	PROJECT	CODE	Envisaged progress
Task A	Decision Making	Interdependence	Modelling investment decisions (including demand response) at distribution network level and determining the methodologies to integrate them in power system planning	R4S3P1	30%
	Distributed Energy Systems	Distributed energy markets and demand-side flexibility	Identifying the sources and availability of demand side flexibility, quantifying its aggregated profile, and determining its representation in power system planning	R5S2P1	40%
Task B	Distributed Energy Systems	Distributed energy resources impact	Modelling the impact of high DERs penetration on power system planning	R5S3P1	20%
Task C	Distributed Energy Systems	Multi-energy systems	Modelling the impact and flexibility embedded in the interactions between power systems and other energy systems for planning studies	R5S1P1	40%
Task D	Reliability and Resilience	Credible and non-credible contingencies	Modelling the impacts and benefits of other infrastructure and sector coupling (e.g., gas, hydrogen) on power system reliability and resilience	R3S3P3	60%

Figure 1-1 Progress completed for the research activities considered in the initial research plan at the end of this project.

1.3 Research relevance and future guidelines

Australia's power system is anticipating substantial growth in distributed energy resources (DER), and particularly consumer energy resources (CER) [2] and the potential for green hydrogen production, both for domestic use and exports, due to the abundant availability of renewable resources and the country's decarbonisation goals. However, current planning approaches do not reflect the potential for developing these resources, typically viewing them as an inherent aspect of the scenarios being analysed. These approaches heavily rely on new transmission to unlock renewable energy zones (REZs) across the country, which transport the generated energy to load centres. This reliance may result in decisions that could lead to stranded, underutilised, or redundant assets and possibly higher costs, as the synergies and trade-offs between large- and small-scale assets, global and local production, or electricity-gas-hydrogen infrastructure are overlooked.

Therefore, improved planning methodologies are needed to address these challenges and make robust decisions about new infrastructure investments across energy systems and vectors. Research is underway to understand the most efficient methodologies for integrating these aspects in planning frameworks. This will enable lower costs, enhanced flexibility, increased efficiency, and reduced renewable energy curtailment. These developments will also provide new perspectives on how decision-making can be distributed across energy

[2] For this report, DER refers to resources such as generators and storage that are connected to distribution networks. Additionally, CER refers to embedded solar systems (residential and commercial rooftop PV) and storage devices (batteries or electric vehicles) owned by consumers. In this sense, DER is a larger set of resources that contains CER.

vectors and networks, building a system capable of achieving net zero emissions at minimum cost.

In this context, this research project studies and quantifies the modelling requirements for and outcomes of integrated planning approaches (e.g., transmission-distribution and electricity-hydrogen), the benefits unlocked by including flexible and adaptive investment options (e.g., storage, demand response, and network reinforcements within active distribution systems, hydrogen storage, fuel cells, and battery storage, among others embedded in hybrid energy hubs), and their ability to defer, displace, or compete with investments in large-scale infrastructure.

These aspects strongly align with the current Australian context, and particularly with the critical priorities for future iterations of the Integrated System Plan. This alignment is also justified by the ambitious objectives of both the Energy and Climate Change Ministerial Council (ECMC) ISP review and NER rule changes[3,4] being undertaken by the AEMC, to achieve an enhanced ISP that provides greater consideration of the role of distribution systems and the interactions between the electricity system and other energy carriers like gas and hydrogen. In this context, this research supports and informs relevant stakeholders, including AEMO, AEMC, ECMC, DNSPs, and more generally in the context of the G-PST consortium, on methodological approaches to efficiently integrate, assess and value the integrated planning of transmission, distribution, gas and hydrogen systems.

1.4 Report Structure

The structure of the report aligns with the four main tasks established for this stage. The second section explores literature on integrated transmission and distribution systems planning, as well as approaches for planning electricity-hydrogen hybrid energy hubs. This review concludes the most suitable approaches for real-world applications, and the potential techno-economic value that integrated planning could provide. The third section is based on tasks A and C of this project, showcasing the proposed methodology for integrated transmission and distribution planning. It includes case studies to analyse the importance of

[3] AEMC, Better integration and community sentiment into the ISP. June 2024. https://www.aemc.gov.au/rule-changes/better-integration-gas-and-community-sentiment-isp-0

[4] AEMC, Improving consideration of demand-side factors in the ISP. June 2024. https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp

CER coordination, and more broadly DER integration, from a small and system-wide perspective, along with the main findings to date. The fourth section focuses on tasks B and D, presenting the methodologies for planning hybrid energy hubs and their integration with transmission planning to optimise system investments and efficiency, followed by NEM case studies and key findings. Then, section 5 summarises the report's key findings and presents the overall conclusions. Lastly, section 6 presents the recommendations for the future developments of the project.

2 Literature review: Integrated energy systems planning

2.1 Integrated planning of transmission-distribution electricity systems

The uptake of DER in power systems is increasing the need for a more comprehensive integration of these resources within transmission planning. Different studies have demonstrated that the flexibility capabilities of such assets could unlock significant techno-economic value and displace traditional transmission infrastructure [4], [5]. Moreover, the value provided by DER has been proven to increase under uncertainty if compared with traditional deterministic approaches [6], and reduce the risk of portfolio of investments [7].

However, key aspects missing from such conclusions are that DER are connected in distribution systems, usually neglected from a transmission planning perspective, and that they are usually considered as inherent feature of analysed scenarios, neglecting possible trade-offs between large- and small-scale resources. In this vein, the integration of transmission and distribution systems planning via coordinated frameworks has been recognised as a crucial need for future power systems.

2.1.1 Real-world efforts

Current planning practices are **independent** with some information exchange between system operators regarding mainly *load forecast and scenarios* (e.g., DER adoption). Thus, there are not many examples where such coordinated framework is in place [8]. However, it has been identified in some countries the need for improving the coordination between transmission and distribution systems going forward, as well as the integration of DER within energy markets.

In the United States, investments in transmission are managed by Regional Transmission Organizations and Independent System Operators (ISOs), which conduct planning for at least three long-term scenarios over a minimum 20-year horizon [9]. However, distribution system planning remains under the jurisdiction of individual states, with each state's Public Utility Commission setting the regulatory framework independently. Despite this separation, some mechanisms have been established for DER to participate in electricity markets through aggregators, who distribute financial compensation accordingly [10].

A comparable structure exists in Europe, where the European Network of Transmission System Operators for Electricity coordinates transmission planning at the continental level through the Ten-Year Network Development Plan. This process involves close collaboration with transmission system operators to ensure that investment strategies align with both national and EU-wide objectives, while distribution system operators remain responsible for planning at the local level [11]. However, recognising the increasing presence of DER, Europe has highlighted the need to enhance coordination mechanisms, including their integration into planning frameworks [12]. Within this broader European context, the United Kingdom is among the frontrunners in developing regulatory policies for DER integration. While DSOs handle planning locally, the Office of Gas and Electricity Markets, which oversees transmission network planning, has placed greater emphasis on flexibility services and collaboration between system operators, aiming to improve DER and demand response management [13], [14].

In the Australian case, the ISP is the roadmap for the energy transition *and identifies network augmentations for transmission systems* [15], while distribution planning is carried out independently annually by DNSPs for 5 years at minimum [16]. Although, as depicted in Figure 2-1, there is room for coordination between system operators (in the form of *Regulatory Investment Test*), this comes after the ISP takes the decisions on the optimal development path and thus the decision-making process is independent.

Figure 2-1: Space for planning coordination between transmission and distribution systems

In this sense, AEMO has identified the need for improving coordination and consider the planning of distribution networks within the ISP, and has begun to develop a methodology to integrate distribution network capabilities, at a sub-regional level, and opportunities for CER and DER within the ISP [17]. This methodology includes distribution network constraints by considering two main limitations: i) the operational constraints of CER due to distribution network limitations and ii) constraints on the uptake of CER and additional DER. These constraints ensure that the distribution network, and possible augmentations, can support the integration of CER and more broadly, DER, without exceeding its capacity.

Moreover, some efforts have been done to analyse the integration of DER from an operational perspective, where AEMO has conducted trials through project EDGE, Edith, Symphony, and Converge identifying the need for of improving DER technical integration, data communication, aggregation, and consumer engagement [18].

Finally, Canada is one of the few countries in which coordination between transmission and distribution within planning is in place. In Ontario, there is coordination between Alectra Utilities (distribution utility), Hydro One (TSO), and the independent electricity system operator (IESO) [8]. However, the reason that such framework is in place is because there is no national planning framework in Canada, and thus the jurisdiction in Ontario establish an the *integrated regional resource planning* process that evaluates various options (generation, transmission, distribution, energy storage, and demand-side management) to meet regional electricity needs in a reliable and cost-effective manner over a long-term planning horizon (10-20 years). Thus, it coordinates the decision-making of transmission and distribution networks to develop a plan that integrates a variety of resource options to address the electricity needs of the region [19].

2.1.2 Coordination methodologies

Although coordinated planning has been identified as a need for future power systems, there are no major cases where transmission and distribution networks are jointly planned on a national level. Thus, to bridge this gap it is crucial to understand what methodologies have been proposed in the literature for coordinated planning and identify the most suitable approaches for real-world implementation.

2.1.2.1 Centralised decision-making

The first methodology is a ***centralised approach*** where a single optimisation problem is formulated, minimising both investments and operational costs. This method assumes that the system planner has complete knowledge over network parameters and resource allocation at all levels (transmission and distribution). In this sense, it is best suited for cases where a single planner has jurisdiction across the entire system, as happens at the regional level in Ontario.

Most of the works found with such an approach focus on comparing whether there is value in coordination against the traditional independent planning approach, demonstrating total cost reductions. These insights have been obtained through deterministic formulations that include storage as investment options [20], [21], or through stochastic approaches to capture uncertainty and focusing on distributed generation [22] and improvements in reliability [23]. However, the computational complexity of this approach, due to many decision variables and constraints, often comes with strong assumptions regarding uncertainty and temporal granularity such as, VRE intermittency, unit commitment, extended planning horizons, etc. Thus, such an assumption doesn't allow for truly analysing the benefits of coordination. As it is highly dependent on data availability, it would be difficult to apply in real-world contexts.

Moreover, ***multi-level approaches*** comprise a hierarchical optimisation problem where the upper level represents transmission system planning, subject to constraints imposed by a lower-level distribution system planning problem. Typically, this methodology is solved by leveraging the Karush-Kuhn-Tucker (KKT) conditions and the strong duality theorem to reformulate the lower-level problem, incorporating it into a single-level optimisation framework.

Like the centralised approach, different studies reveal potential investments and operational cost reductions. For instance, [24] highlights cost reductions from considering DER impacts on transmission planning but neglects distribution network constraints, leading to potentially inaccurate conclusions. Distribution network constraints are included in [25], [26], exploring distribution network flexibility but with no investment decisions at the distribution level, failing to capture trade-offs between large- and small-scale investments. Additionally, [27] extends the analysis to include reinforcements in both transmission and distribution networks, but the model is limited to a single-year planning horizon due to computational limitations. Overall, these works fail to address comprehensive results mainly because the equivalent single-level formulation is a large-scale problem. This is somewhat tackled by authors in [1] by using multi-parametric programming directly into the distribution planning problems to simplify the equivalent single-level formulation into multiple parametric problems that are more manageable computationally.

However, despite its advantages in capturing multiple stakeholders' interests, multi-level approaches still require full system knowledge to reformulate the optimisation problem into a single-level one, same assumption as a centralised approach. This poses a significant barrier to real-world implementation, due to regulatory frameworks and the need for huge information exchange between TSOs and DSOs, or the need for an independent planner that manages all the information.

2.1.2.2 Distributed decision-making

To avoid the large-scale formulation that comes with previous approaches, ***distributed decision-making*** has been proposed in the literature. It consists in introducing communication variables between TSO and DSO planning problems, which could be prices, power exchange, among others. By facilitating structured information exchange without requiring full system knowledge, this methodology enhances coordination while preserving operational and regulatory independence.

A distributed **iterative approach** allows solving transmission and distribution planning problems sequentially until a convergence criterion is met [28]. This approach is typically implemented under the assumption of TSO-DSO coordination through a price interface (i.e., prices are the exchanged variables) [29]. Studies have analysed the impact of DER on investment decisions [30] and explored transmission cost allocation strategies [27], [28], demonstrating cost reductions, improved resource allocation, and computational efficiency. However, these studies focus on short-term planning horizons and overlook long-term uncertainties such as VRE and DER adoption, demand growth, or technological advancements and costs.

Addressing the temporal aspect, 10-year planning horizon have been analysed [33], [34], yet the computational complexity of the transmission and distribution planning formulation limits their ability to incorporate flexible investment options. These are integrated in [35] by modelling energy production and conversion technologies, distributed generators (DGs), combined heat and power units, boilers, and heating/cooling pipelines within distribution networks. However, simplifications such as time block representation for operation limit the ability to capture VRE intermittency and the long-term value of flexibility accurately.

Despite reduced data exchange requirements, an iterative approach requires solving both planning problems simultaneously to ensure variable convergence. This requirement can be challenging for real-world implementations as it would practically necessitate multiple instances for information exchange.

Finally, a **decoupled approach** follows the principles of employing a reduced set of variables and/or constraints to communicate transmission and distribution planning problems. However, unlike iterative methods, this approach decentralises decision-making by solving planning problems independently while exchanging specific and limited information, reducing instances of communication. By doing so, this approach could enhance computational tractability, scalability, and real-world applicability, paving the way for effective planning coordination across systems.

An example of a decoupled approach is presented in [36], which employs a top-down, multi-stage heuristic method to coordinate transmission and distribution planning, incorporating network and storage investment options at all levels. Case studies on the German power system reveal only marginal cost savings, which could mean limitations in broader applicability or methodological shortcomings. Similarly, [2] develops an integrated framework by decoupling decision-making problems, representing distribution systems with a surrogate single-bus model that aggregates generation, load, and storage. Thus, the transmission expansion planning problem is solved using this representation, after which the fixed TSO-DSO power exchanges are incorporated into the detailed distribution planning model.

The latter methodology is employed in [37] to examine coordinated planning for the Italian power system using synthetic distribution networks. However, this study focuses on comparing demand flexibility and storage versus conventional reinforcements in congestion zones rather than assessing the broader role of distribution systems in coordinated planning. Furthermore, the authors highlight significant computational burdens associated with fully integrated models, suggesting that further simplifications are necessary.

2.1.3 Main findings

The integrated planning of transmission and distribution systems holds substantial promise for achieving more efficient power system developments, both technically and economically. Nevertheless, the success of real-world applications depends on developing integrated planning methodologies and coordination schemes that support ***distributed decision-making***. This approach would allow system operators to maintain their roles, preserve their current tools and share the workload among entities (e.g. AEMO and DNSPs in Australia), while keeping most of the planning process structure at different system levels. Moreover, this approach would enable more informed decisions based on local communication.

In this context, ***iterative*** and ***decoupled*** methodologies emerge as the most suitable option for real-world applications as they support parallel and distributed computing (system planners can solve their own problems and produce information), which allows for distributing decision-making into manageable formulations. Based on this, the main difference between iterative and decoupled approach is the instances of communication. For instance, an iterative approach would require a process of information exchange between DNSPs and AEMO to achieve a global solution, whereas a decoupled approach would formulate a single planning problem based on the information produced by distribution network planning, that is, AEMO would include DNSPs information in a single step within the ISP. Thus, the latter approach would translate into more computational efficiency, it can open the possibility for considerations of uncertainty, or even whole-system decision-making where distribution systems could be treated as investment decisions.

2.2 Planning of electricity-hydrogen hybrid energy hubs

Energy hubs can optimise local energy management by leveraging economies of scale and efficiency to maximise resource utilisation and minimise costs [38]. With a growing focus on the green H_2 economy, electricity-hydrogen hubs are gaining attention as H_2 serves as both a crucial industrial feedstock and a flexible energy carrier, and green H_2 generated from renewable energy can be used to decarbonise some hard-to-abate sectors.

Electricity-hydrogen hybrid energy hubs integrate electricity and hydrogen systems to efficiently manage energy generation, storage, and distribution, providing operational benefits while enhancing integrated system flexibility and reliability. Integrating the planning of such hybrid hubs optimises resource utilisation and reduces costs by minimising connection assets and conversion losses [39].

Therefore, the design of hybrid energy hubs must be carefully performed and validated jointly within existing generation, transmission, and storge planning, considering the represented technologies, their interactions, and the level of detail required for different planning studies. Additionally, integrating electricity and H_2 transmission planning with hybrid energy hub design can further provide valuable insights into cost-effective strategies for expanding the energy system and broader implications for the energy transition. Achieving this requires determining an adequate level of network resolution while maintaining computational tractability.

2.2.1 Benefits of electricity-hydrogen hybrid energy hubs

Electricity-hydrogen hybrid energy hubs integrate components such as renewable generators (e.g., solar panels, wind turbines), electrolysers, batteries, H_2 storage, and H_2 gas-fired generators *behind* shared connection assets. Unlike traditional planning approaches that optimise investments at individual grid buses, this hub-based design leverages co-location and integration to deliver distinct advantages [40], such as increased energy system flexibility and improved energy system reliability.

By co-locating multiple components behind a shared connection asset, electricity-hydrogen hybrid energy hub leverages the diversity across different technologies. This can reduce the total capacity of connection assets, including high-voltage (HV) substations and feeder. In traditional **bus-level independent planning**, each component (e.g., a solar array or an electrolyser) requires its own HV substation which includes MV/HV transformers, switchyard, reactive plant, and other associated equipment, along with a dedicated feeder to connect to the grid. In contrast, the **hub-level integrated planning** approach allows multiple components within a hub to share these assets, minimising the aggregated HV substation and feeder capacity required for grid connection, as depicted in Figure 2-2. The Australian Energy Market Commission (AEMC) considers that coupling battery and solar PV generators behind a single grid connection point can lead to potential savings of approximately 10 to 20 % in setup and connection costs [41].

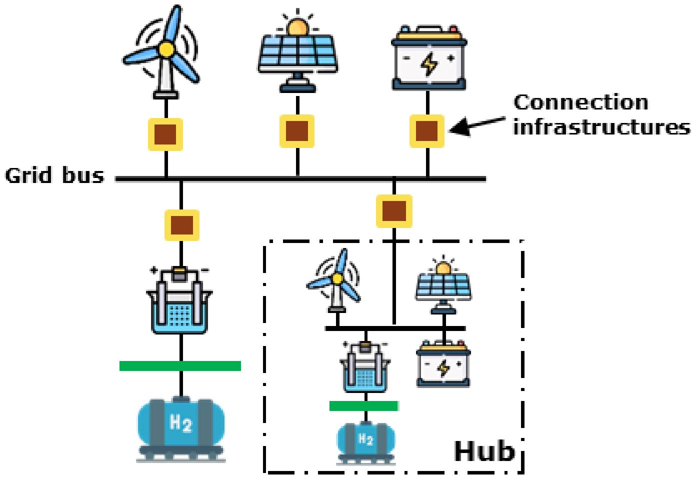

Figure 2-2: Illustration of independent components investment and hybrid hubs investment at grid buses.

As illustrated in Figure 2-3, DC coupling within hubs directly connects DC-based components, such as solar panels, batteries, and electrolysers, thereby avoiding AC/DC conversions and voltage step-up/down processes [42], [43]. While this strategy can offer some benefits, the costs and configurations of large-scale DC-DC converters are often project-specific or custom-designed, and detailed, scalable cost data are not readily available. As a result, their overall cost impact compared to AC-coupled systems in energy hubs remains uncertain [44]. Therefore, most studies [45], [46], [47], [48], focus on AC-coupled configurations, where cost and technical parameters are better documented and more consistently applicable across different system scales.

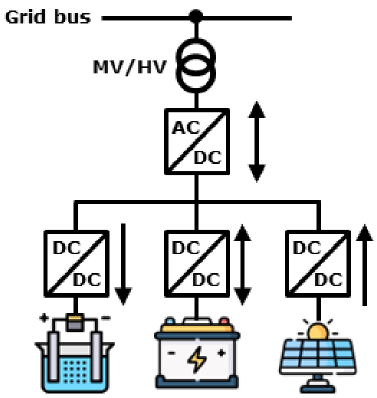

Figure 2-3: Illustrative DC-coupled system in hybrid hubs.

Even with AC coupling, as shown in Figure 2-4, the **hub-level integrated planning** approach offers advantages over **bus-level independent planning** approach by allowing energy to be collected at a shared medium-voltage (MV) bus, which enables a single MV/HV step up/down process through shared connection assets to match the voltage for grid connection. This configuration leverages diversity and allows for better local energy management, reducing power flow through the connection assets and thereby improving overall system efficiency.

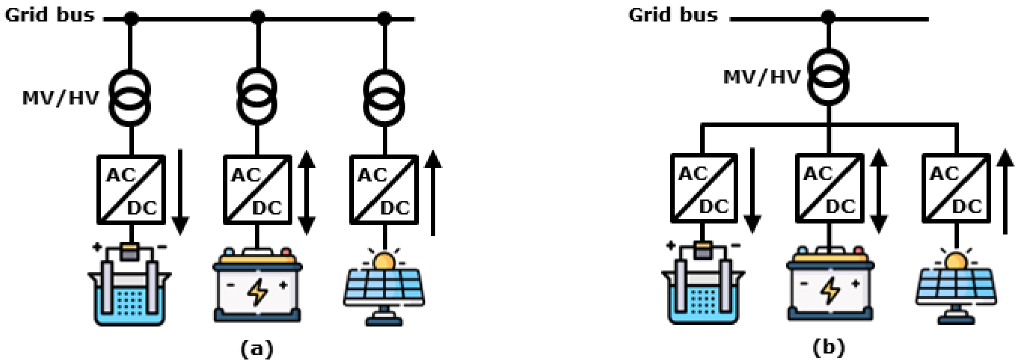

Figure 2-4: Illustrative examples of AC coupling (a) bus-level independent components and (b) hub-level integrated components.

Additionally, the coupling of components may further facilitate the participation of storage systems in the electricity market and help increase the proportion of fast-responding dispatchable resources [41]. This enhances system reliability and security by enabling storage to rapidly respond to fluctuations in supply and demand, while allowing the system to quickly adapt to the intermittency of VRE, which are needed to support increasing integration of renewable generation.

2.2.2 Electricity-hydrogen hybrid energy hubs in system planning

The state-of-the-art in electricity and hydrogen system planning primarily focus on **bus-level planning**, where electricity components such as solar, wind, electrolyser, and BESS are optimised independently at individual grid buses. This approach treats each component as a separate investment with its own connection assets, and the potential advantages of coordinated planning with shared connection assets are often not captured [47], [49], [50] . While most studies characterise their models as hub-level planning due to the physical co-location of resources [52],[51]. However, these works generally do not explicitly separate, for each investment option, the connection assets (e.g., transformers and feeders) from the main equipment (e.g., solar panels, wind turbines, cables, overhead lines). Additionally, these works do not account for the specific costs and efficiencies associated with each of these components. As a result, their approaches are similar to traditional bus-level investments, where components are geographically proximate but operate separately. This bus-level planning approach can lead to overestimated capital costs and inefficient energy flow due to redundant equipment.

A **hub-level planning** approach aims to leverage shared connection assets and optimise energy flows to achieve quantifiable advantages, including lower capital costs and improved system efficiency [44]. This approach is particularly relevant in contexts like Australia, where REZs have been identified by AEMO across the NEM, presenting opportunities for coordinated investment and shared infrastructure development. However, most existing literature, such as the ones in [48], [52], focus on hub-level configurations without comparing them against independent, bus-level investments, and therefore do not quantify the potential benefits of integration. In scenarios where VRE potential is limited, it may be more cost-effective to install BESS directly at grid buses rather than co-locating it with VRE generation in REZs that are distant from the grid. This underscores the importance of planning methodologies that explicitly assess and quantify the benefits of hub-level integration with shared connection assets.

However, the benefits of hybrid energy hubs extend beyond local optimisation, influencing transmission infrastructure needs across the integrated energy system. The integration of transmission planning with hybrid hubs is not widely examined in the literature, particularly in terms of how leverage diversity across different technologies within a hub can reduce the need for additional transmission infrastructure. By efficiently coupling technologies within hubs, local demand can be met at lower investment and operational costs. This may reduce the investments in additional transmission infrastructure to transport energy over long distances. Exploring this relationship could provide valuable insights for system-wide planning, helping to minimise both local and long-distance transmission requirements while optimising investment and operational costs across the entire energy system.

Furthermore, most studies [48], [53], [54] overlook how hybrid hubs with H_2 transmission can enhance system reliability and resilience. Co-locating generation, storage, and H_2 production within a hub enables more coordinated and flexible infrastructure investments. Additionally, H_2 pipelines offer an alternative means of energy transport and storage, complementing traditional electricity transmission lines and local stationary storage. These features become particularly valuable during extreme events such as VRE drought periods, helping to reduce the impact of disruptions and enhance overall system resilience.

2.2.3 Main findings

Hybrid energy hubs can potentially enhance efficiency, flexibility, and cost savings by integrating electricity and H_2 systems. Unlike traditional bus-level planning, which treats technologies independently at individual grid buses, hybrid hubs co-locate generation, storage, and H_2 production, enabling shared use of connection assets such as feeders and transformers. This coordination reduces capital costs and improves energy flow efficiency by minimising the size of connection assets and reducing the number of voltage conversions across the system.

Most existing studies overlook direct comparisons between bus-level and hub-level planning and therefore fail to quantify the benefits of hub-based coordination. Although many claim to adopt a hub-level approach, they typically do not distinguish shared connection assets from primary equipment, nor account for the associated costs. As a result, the potential of hybrid hubs to reduce connection redundancy and lower capital costs remains insufficiently examined.

Additionally, the impact of hybrid hubs on transmission planning remains insufficiently studied. By localising energy use, these hubs have the potential to reduce the need for additional long-distance transmission investment. When coupled with H_2 transmission, they may also enhance system resilience by enabling more flexible investment strategies and offering alternative energy transport methods during extreme events such as VRE droughts. This highlights the need for further research to support cost-effective and energy-efficient system-wide planning.

2.3 Key insights

Key insights obtained from this review include:

- **I.** Integrated planning of transmission and distribution systems shows significant promise to deliver cost-efficient developments for future power systems, as well as capture trade-offs between large- and small-scale resources in a coordinated fashion
- **II.** To achieve this, methodologies are needed to leverage the know-how capabilities of system operators and planners in order to achieve a seamless transition that does not require huge regulatory changes, and causes actionable impacts in future power system development paths
- **III.** Hybrid energy hubs can leverage diversity across different technologies through shared connection assets within a hub, reducing the total capacity of connection

assets. A modular and scalable framework is needed for the design and assessment of these hubs, enabling flexible and cost-effective integration of components

IV. A comprehensive planning framework is needed to integrate transmission planning with hybrid energy hub design to provide valuable insights into cost-effective strategies for expanding the energy system while improving system reliability and resilience

3 Methodology for integrated planning of transmission-distribution electricity systems

3.1 Active distribution systems planning

Insights from the previous literature review show that the most suitable way to enable an actionable integrated planning framework is by developing a methodology based on ***distributed decision-making***. Hence, in this project, we propose a framework for planning active distribution systems as a parametric function of DER adoption and/or coordination. This function embeds both the annual investment costs (network infrastructure) needed to support these resources, as well as the flexibility (in terms of power capacity) unlocked within distribution to the upstream system.

This methodology consists of an investment and operational framework as illustrated in Figure 3-1. First (step #1), by minimising investment and operational system costs, we build an *investment cost function* that informs the necessary investments within a distribution network to unlock a level of DER adoption over an array of potential DER capacities[5], which could relate to planning scenarios, coordination of resources, available flexibility, etc. Hence, each point in an investment cost function describes a pair of network investment cost (*y-axis*) and accessible DER capacity (*x-axis*).

Secondly (step #2), we iterate over each pair of network investments and DER capacity that builds the investment cost function. Then, for each pair, an optimal power flow (OPF) is performed for each representative periods (e.g., days, weeks, etc.). This OPF allows capturing the flexibility available from DER, given a certain level of investments, to support the export and import limits of a given distribution system under network constraints (e.g., voltage and thermal limits). As an output of this process, an equivalent model is found, which is characterised by generation, load, and storage components.

Therefore, this methodology provides two steps that DNSPs could follow to produce planning and operational information regarding future scenarios (e.g., CER coordination, DER adoption) while using with their own tools, and communicate it to the central planner, such as AEMO, allowing for a more informed integrated decision-making process.

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[5] Also referred to as parametrisation in this report

Figure 3-1: Proposed methodology for active distribution system planning

3.1.1 Investment framework

We developed this investment framework based on a least total system cost optimisation problem that determines a set of investments to support a specified level of DER capacity over the planning horizon. The associated investment and operational constraints can represent any level of distribution systems. The proposed optimisation formulation is deterministic, meaning that it does not account for uncertainties associated with expected DER (i.e., well-known scenarios) when making investment decisions, although this could be covered by analysing multiple scenarios that could cover uncertain parameters. Nevertheless, this work aims to show methodological steps for the integration of active distribution system planning and management within transmission planning. Hence, a deterministic approach fits in well for this purpose.

The mathematical formulation of this framework accounts for investments and operational constraints, *which are detailed in Appendix A*. Investment decisions are associated with either binary variables, to account for distribution network reinforcements (transformers and lines), or integer variables for non-network solutions, mainly reactive compensation, distributed batteries, and CER coordination when analysed. Operational constraints include power availability (time-varying) and storage limits of any DER (CER included). A linear AC power flow models voltage and thermal limits of the distribution network. Constraints also ensure the balance of generation and demand at each node of the network. Power imports or exports at the system interface (e.g., connection to the transmission system) are constrained by the capacity of the distribution network downstream.

Thus, for every DER adoption level, a parameterised execution of the planning problem is completed (i.e., a least-cost operation-investment system optimisation is run considering a fixed level of DER adoption). This parametrisation over DER levels could represent scenarios such as the ones modelled by AEMO in the ISP (Step Change, Progressive Change, Green Energy Exports), or even the level of control over expected CER. In this regard, the annual investment costs could include those of the infrastructure needed to orchestrate CER, meaning that CER coordination (e.g., storage from EVs, batteries, heating/cooling loads, hot water, etc.) could be quantified as a decision of the model to solve local issues within distribution systems, and its impact when coupled with transmission system planning.

In turn, this iterative process allows finding the optimal portfolio of investments and the corresponding annualised costs (annuity of investments) for each level of DER adoption, i.e., a **parametric investment cost function of DER adoption**. This framework can be applied to any reference node within distribution networks, meaning that this information can be produced at any voltage level, and communicated upstream the network.

Finally, the degree to which the distribution network is actively managed while applying this methodology will significantly impact the resulting parametric investment cost function. This means that with low levels of flexibility and active network management in distribution networks, investment decisions will be driven by inflexible demand. Eventually, some of these investments may be displaced or deferred when higher levels of flexibility and control schemes, such as curtailment, reactive compensation, and CER control, are implemented. Consequently, annual investment costs could decrease, making DER adoption more cost-effective. These aspects will be analysed through the case studies proposed in this project.

In this sense, there will be trade-offs between the provision of local flexibility services and investments in network reinforcements. For instance, DNSPs could plan distribution networks with two philosophies: a) minimising costs (a least-cost plan) where control over CER could be leveraged to reduce investments, or by b) identifying future portfolios where additional investments are in place for CER to provide services to the system upstream (e.g., transmission system). The latter may not be the minimum cost solution for the distribution system, but rather for the whole system (unlocking huge value at the transmission level).

3.1.2 Operational framework

Through a parametric investment cost function, it is possible to value the upgrades needed within distribution networks to support multiple levels of DER, maximising flexibility. This output could be produced and communicated by DNSPs through their own planning frameworks. Nevertheless, it does not provide direct information on the operational flexibility that can be leveraged within the parametric DER adoption, unless the whole distribution network and DER are modelled in detail (all variables and constraints). This would not differ from the most common approaches presented in the literature, hindering the real-world applicability of an integrated planning framework.

Therefore, to achieve a scalable integrated planning framework where the central planner (e.g., AEMO) can manage the resources within distribution networks' thermal and voltage limitations, we developed an operational framework based on the concept of nodal operating envelopes (NOEs). NOEs allow characterising the flexible limits of distribution systems, that is, maximum exports and imports (active and reactive power) for which the system can securely operate under network constraints from any reference node [49]. In addition, NOEs can be aggregated, allowing to assess technical limitations across an entire distribution system (e.g., LV, MV, and HV) without exchanging sensitive information. Thus, they can facilitate the integration, market participation, and coordination over DER aggregations. Therefore, NOEs can effectively represent *the operational capabilities of active distribution systems as a simplified set of linear constraints, from any reference node.*

In this sense, the aim of coupling NOEs with a parametric investment cost function is that we can characterise the operational capabilities of any distribution system, for all levels of DER adoption within the chosen parametrisation, and in turn, flexibility within distribution systems is maximised. However, aside from DER adoption and investment decisions, NOEs will also depend on the availability of these resources in time. Hence, NOEs are determined dynamically for all analysed representative periods, which could be hours, days or weeks, as well as for all points within the parametrisation or planning scenarios (e.g., pair of DER adoption and investment decisions).

To determine these NOEs dynamically, an optimal power flow with network and temporal constraints is formulated for all representative periods. This formulation is based on the investment framework but fixing each pair of investment decisions and DER adoption, where the objective is to maximise self-consumption. From this operation, the maximum exports (i.e., minimisation of consumption from transmission system) and imports (i.e., maximisation of consumption from transmission system), are dynamically determined. This allows to find what and the degree to which flexible assets can change their operation from the base operation to support exports and imports in each time-step.

Thus, to show the relationship between the investment and operational framework, we introduce the IEEE-33 bus distribution network of 12.6 kV [55]. This MV feeder is characterised by a peak demand of 3.7 MW and 2.3 MVAr. To consider some sort of flexibility, we allocate distributed storage totalling 2 MW, and rooftop PV in each node with demand, totalling 2.4 MW. The time-varying traces, and assumptions regarding the ratio between peak demand and rooftop PV adoption, are aligned with the ***step-change*** scenario from the ISP 2024 [56]. Although this example is for illustrative purposes, aim at providing a clear understanding on the principles of the proposed methodology.

Figure 3-2: IEEE 33-bus test distribution network.

Then, we compute NOEs as depicted in Figure 3-3 for two different snapshots within a representative day (with and without rooftop PV generation). Here, a) shows the aggregated DER flexibility from the connection point to the transmission system ***if there were no distribution network constraints***, but as seen in b), these ***NOEs must be constrained by voltage and thermal limits to guarantee a secure operation of the distribution system***, which turns into reductions of the maximum imports that the distribution network can support, going from 5 MW (result of rooftop PV curtailment and the charging of VPPs) to around 3.5 MW at the time of peak solar generation, while from 4.5 MW to 2.6 MW approximately when there is no solar generation.

a) NOE of aggregated DER

b) NOE with network limits

Figure 3-3: Illustration on how NOEs, representing aggregated DER within the IEEE-33 bus distribution network, is limited by network constraints

Based on this, if the adoption of DER were to increase (following the parametric approach of this methodology), the flexibility available from these resources would be even more constrained by the distribution network's hosting capacity. Thus, investments such as network reinforcements, reactive compensation, and other non-network solutions, are needed to exploit this additional flexibility. In this context, we consider a case where the DER adoption mentioned previously is doubled.

Figure 3-4 illustrates, for a snapshot with peak solar generation, how investments in reactive compensation and later, network reinforcements, could enhance the flexibility that can be leveraged from DER, while Figure 3-5 illustrates the same principles but for a snapshot with no solar generation. It is important to mention that even though non-network solutions (e.g., reactive compensation or storage) can displace network reinforcements and increase flexibility in terms of reactive power (which can unlock active power) and duration (energy storage), it will come a point in which, to connect additional DER, the network must be reinforced as otherwise, the exports and imports limits will remain the same in terms of capacity. Although these figures are for illustrative purposes, the investments decisions will be optimally determined as a result from the investment framework. Thus, as DER adoption increases, as well as the investments to support this adoption, NOEs will increase in size, meaning that more flexibility within distribution systems is available to the upstream network.

a) Additional Rooftop PV under network limits	*b) Additional Rooftop PV and Q investments*	*c) Additional Rooftop PV, Q and network investments*

Figure 3-4: Illustration on how NOEs, representing greater levels of aggregated DER services within distribution networks at peak solar generation, can be enhanced by appropriate investments

a) Additional Rooftop PV and network limits	*b) Additional Rooftop PV and Q investments*	*c) Additional Rooftop PV, Q and network investments*

Figure 3-5: Illustration on how NOEs, representing greater levels of aggregated DER services within distribution networks with no solar generation, can be enhanced by appropriate investments

3.1.3 Equivalent model to represent active distribution systems

Thus, as shown in Figure 3-6, from NOEs that characterise distribution system's operational flexibility for each investment path (e.g., parametric cost function) and dynamically for each snapshot within all representative periods, we can analyse how flexible assets can change their operational states towards exports and imports compared to the base operation.

Figure 3-6: Dynamic P-Q flexibility ranges from NOEs

From this comparison, we then compute an equivalent model consisting of a generator (renewables, curtailment, and non-renewables), flexible load (inflexible and flexible loads associated to demand response schemes), and storage component as illustrated in Figure 3-7. ***Thus, these components capture the power limitations of each technology while satisfying network constraints.*** Hence, the management of active distribution systems can be modelled through the time-varying limits of these components, which are defined for all representative periods within the investment cost function, as a set of linear constraints, including a state of charge constraint limited by the available storage within the network and the time-varying charge and discharge limits of the equivalent model. In this sense, the system planner can decide the optimal level of distributed resources based on this investment cost function, and through the equivalent model, their management for transmission planning purposes.

Figure 3-7: Equivalent model that represents distribution system's operational capabilities

Moreover, the mathematical formulation to determine the equivalent model that represents the operational capabilities of active distribution systems is detailed in the Appendix B of this report, where the energy component associated to storage is managed optimally within the integrated planning framework to minimise whole-system total costs. It is worth mentioning that one of the limitations of this equivalent model is that it only represents flexibility in terms of active power (even though reactive power is accounted for in previous steps), which mathematically depends on reactive power and the voltage at the interface with the transmission system. Nevertheless, it serves as a good approach as transmission power flows for planning purposes are usually modelled through transports or DC models, assuming voltages at 1 p.u. and thus, neglecting reactive power.

Furthermore, the integration of this methodology is made in one optimisation step, meaning that after distribution system planning information is computed (investment cost function and associated equivalent models), it is directly communicated to any transmission planning problem, solving an integrated framework as if distribution system were an additional investment option with defined operational limits.

Finally, DNSPs could use these principles to produce information regarding network limitations (e.g., power flows, operating envelopes, hosting capacity) for future development paths represented as a parametric investment cost function. Thus, this would clearly inform system planners how much DER flexibility, and from which technologies, can be managed from the transmission system, where distribution systems investment paths would be integrated as options for decision-making under a transmission-distribution planning framework.

3.1.4 Planning active distribution systems

The methodology proposed in this work is flexible in terms of applications, that is, it can be applied to any network and from any reference point. Thus, *ideally, it could be used through a bottom-up approach*, aggregating LV networks and representing them in MV networks, assessing the impact of CER integration and coordination, continuing this process all the way up to the subtransmission level, where future DER path could be analysed (e.g., scenarios of larger scale resources connected to distribution networks).

Nevertheless, although in principle DNSPs could potentially make this assessment as they have knowledge across all levels of their networks, this project relies on distribution networks' test models that may not represent all the limitations of distribution systems (across all voltage levels). However, they serve as good examples to show the information that can be produced by DNSPs, as well as what drives some investments within distribution networks to unlock DER.

3.1.4.1 7-bus MV network

As a first analysis, a reduced 7-bus 22 kV MV feeder is introduced in Figure 3-8. It is characterised with a network capacity of 10 MVA, a peak demand of 7.5 MW and 1.9 MVAr, and rooftop PV adoption of 2 MW. Here, we consider the connection of three distributed solar units, each of capacity 1 MW, representing a total of 3 MW which we parametrically increase evenly (e.g., steps of 3 MW). In terms of investments to enhance the network, we consider the possibilities of investing in network reinforcements, cables at 7,000 $/MVA/km[6] and transformer at 100,000 MVA[7], reactive compensation at 200 $/kW, and storage as non-network solution at 1,500 $/kW and 2,700 $/kW for 2 and 4 hours respectively [56]. Additionally, to understand the impact of coordinating CER when planning distribution networks, the load shifting service is modelled as a percentage of the demand in each time step (constraints for upward and downward shifting, recovery time and payback as in Stage 3-Topic 4 of the CSIRO-GPST roadmap).

In addition, the coordination of CER comes at a cost associated to the infrastructure needed to share data. These are found in the cost-benefit analysis made in project EDGE that considers three different alternatives for coordination[8], *point-to-point, centralised hub, and decentralised hub* [57]. The cheapest alternative is the ***decentralised hub***. Therefore, this is the solution assumed in this project and represents a ***total capital cost of 2,000 $/MW*** [9], which accounts for the decentralised hub infrastructure needed for the expected CER adoption (capacity in MW) according to the projections from the ISP 2022 (study is based on these results from AEMO).

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[6] Nacmanson, William & Ochoa, Luis(Nando). (2020). Deliverable 5 "Cost Comparison Among Potential Solutions". 10.13140/RG.2.2.25888.20481/1.

[7] Transmission Costs Database 2023. AEMO.

[8] **Point-to-point** – closest to the current arrangement in the market, where integration occurs between each participant in the facilitation of DER use cases and services. **Centralised data hub** – each participant only needs to integrate with a common industry data hub once, with data exchanged via a central broker (assumed to be AEMO). **Decentralised data hub** – each participant only needs to integrate with a common industry data hub once, with data exchanged between participants in a way that does not rely on a single central broker.

[9] The solution has a total cost of M$ 105 for a 20-year period horizon and a discount rate of 4.43%. Thus, using the expected adoption of DER from the ISP, and a fixed investment cost for the whole period, it is possible to find the cost proposed in this report.

Figure 3-8: 7-bus network case study

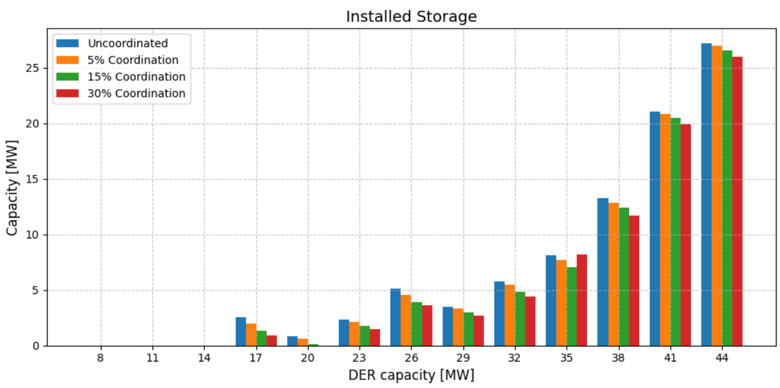
Thus, Figure 3-9 presents the investment cost function that results from increasing the capacity of solar distributed generation (parametric approach), as well as the impact of coordinating CER (e.g., load shifting). In this case, the cost function follows an increasing behaviour which is explained by investments in additional network capacity, distributed storage, and reactive compensation to maximise flexibility. This is achieved through the minimisation of curtailment to incentivise investments in distribution infrastructure. Nevertheless, it is important to mention that some investments can be avoided by allowing curtailment from DER, aspect that will be explored in the following subsection.

In addition, when coordination of expected CER is included with the corresponding capital costs, some investment decisions on network reinforcements, reactive compensation, and distributed storage are avoided. This occurs due the additional flexibility from CER, allowing a better management of the consumption pattern of the distribution network, solving local problems that were solved by investments (distributed storage mainly) when no coordination was considered. Thus, the coordination of these resources can provide benefits when planning distribution systems, benefits that are not quantified in the ISP 24.

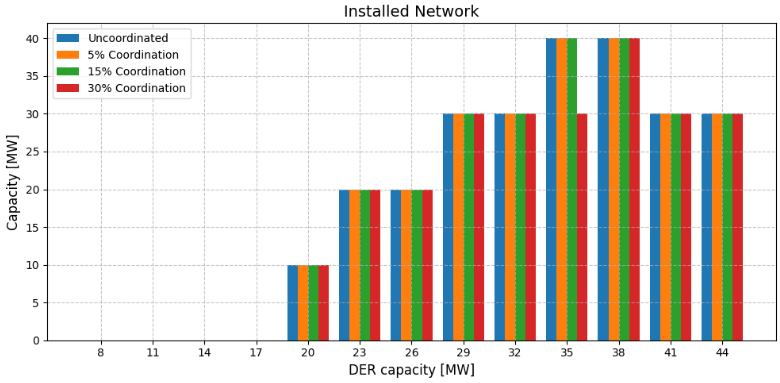
These costs represent additional infrastructure needed to support increasing levels of DER, while securely operating the distribution network. As decision-making over CER, or more broadly DER, is decoupled from distribution planning, we focus on analysing the alternatives that are cost-effective to incorporate resources in distribution systems. Nevertheless, if we would aim at comparing investments not only on infrastructure but also on additional DER, the investment costs associated to these resources could be included when producing this information. This will be explored further in the following sections.

Figure 3-9: Investment cost function for levels of CER coordination

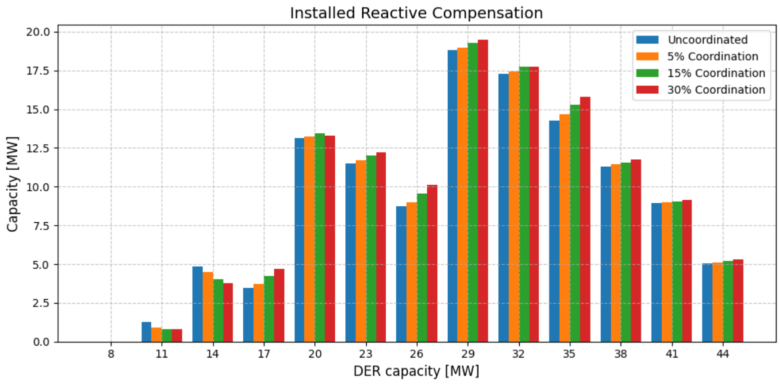
A more detail insight on the investments that come from this case study are presented in Figure 3-10, where the first investments taking place are associated to non-network solutions such as distributed storage and reactive compensation, allowing a more active management of the network, delaying traditional investments. However, it comes a point in which to support the exports of the distributed solar, when the total capacity reaches 20 MW, additional network capacity is needed. Finally, towards the end of the parametrisation, the reactive compensation needed decreases due to the additional storage, asset that can provide reactive support and reduce curtailment.



a) Installed storage capacity



b) Network reinforcements capacity



c) Installed capacity of reactive compensation

Figure 3-10: Investments in infrastructure to support parametric adoption of DER

Moreover, each of these pairs of DER adoption and investment decisions, can be represented with the time-varying parameters the equivalent model components (e.g., generation, load, and storage) through the operational framework. Exploring the active power flexibility limits of the network with dynamic NOEs, allows to determine how these resources can support those limits based on their availability, and the operation and limits of the network.

Thus, Figure 3-11 and Figure 3-12 illustrate the active power flexible limits, for a representative week, for scenarios with 23 MW and 35 MW of distributed solar adoption respectively. It can be seen that flexibility limits of distribution systems increase with the adoption of DER and a more active management of resources through the inclusion of distributed storage, asset that not only provides inter-temporal management, but also that network enhancements and reactive compensation play a crucial role to extend these limits in terms of power.

Figure 3-11: Flexible limits for 23 MW of DER adoption

Figure 3-12: Flexible limits for 35 MW of DER adoption

Furthermore, the following step is to determine the equivalent model associated with each pair of DER adoption and investment decisions, which is the form of modelling the planning of active distribution systems in an integrated planning approach. In this sense, we compute this equivalent model for the case with 35 MW of DER adoption, and with the time-varying parameters of the generator, load, and storage components, we reproduce the operational framework to find the flexibility limits. This is presented in Figure 3-13, comparing these results with the ones from the methodology proposed by authors in [58].

It can be seen that the formulation from [58] underestimates the maximum level of active power imports that the distribution system can sustain, while the flexible limits produced with the equivalent model proposed in this project resemble the limits from the full network model (as seen in Figure 3-12). In this sense, the proposed method in this project enables an efficient and accurate way of representing distribution networks, capturing their flexibility without the need of modelling network constraints (these are already factored when computing the equivalent model) when integrated within transmission expansion planning frameworks.

a) Equivalent model computed as in [58]

b) Equivalent model proposed in this project

Figure 3-13: Comparison of the active power flexible limits by using the time-varying parameters of generator, load, and storage from the equivalent model

3.1.4.2 IEEE-33 node MV feeder

To further showcase the applicability of this methodology, we consider the IEEE-33 bus test MV feeder for the following case studies, which is characterised by a peak demand of 3.7 MW and 2.3 MVAr, a voltage level of 12.6 kV and network capacity of 7.2 MVA [55]. Thus, as shown in Figure 3-14, we analyse the impact of planning active distribution systems jointly with the integration of DER, increasing the capacity of ***distributed solar or wind connected at buses 12, 19, 22, 23, considering units of 0.5 MW that can increase maximum adoption of 6 MW.*** Investment options include reactive compensation, network reinforcements, and the possibility of distributed BESS (illustrated in orange in the figure). The cost functions presented in this section only account for investment costs in infrastructure, costs that are based on the same assumptions from section 3.1.4.1.

Figure 3-14: IEEE 33-bus case study, integration of solar and wind generation

Since we are assuming that we can connect solar or wind in the buses mentioned, it is worth understanding the importance of proactive distribution network planning when integrating DER, and how this could greatly benefit the adoption of these resources. In this sense, Figure 3-15 compares investment cost functions, associated to the connection of distributed solar, that evenly distributes DER across the system (each bus has the same DER capacity), and when the optimisation freely decides what capacity to connect in each bus to achieve the desired adoption in each DER level of the parametrisation.

At around 12 MW both investment cost functions start differing. This occurs due to additional investments in storage and reactive compensation because the same DER capacity is connected *at buses 12, 19, 22, 23.* Whereas when jointly planning the network with the integration of DER, *the network's hosting capacity can be fully exploited*, taking advantage of larger capacities in zones with more demand, such as buses 23 and 29 (concentrate almost 2 MW out of the peak 3.7 MW), and near the top of the feeder in bus 19, delaying the connection at bus 12.

Figure 3-15: Parametric investment cost function when comparing even increments of distributed solar capacity across the network with optimally allocating capacity, unlocking value when planning distribution networks

Then, both cost functions converge in the last point in the parametrisation, at around 26 MW, where the same investments are needed to fulfil the maximum capacity because each bus has an imposed limit of 6 MW and thus, DER is evenly spread in the network. Therefore, this methodology can enhance the understanding regarding the synergies within distribution networks such as technologies, demand profiles, and hosting capacity. This in turn would help reducing total investment costs when integrating DER over time.

Having understood the importance of proactively planning distribution networks jointly with the integration of DER, another relevant aspect is the curtailment from DER, and its value when planning distribution networks. To address this, we constructed parametric investment cost functions for levels of DER curtailment of 0%, 15%, and 30% of the available DER generation per snapshot. This is modelled as a constraint that limits curtailment to these levels to incentivise investments that maximise the exports of the network, meaning having the capacity to inject 100%, 85%, and 70% of the available DER capacity. Thus, although this is the case for planning purposes, in operational terms, each scenario could curtail energy for the purposes of maximising imports.

Additionally, we compute an additional scenario where curtailment is penalised with a cost. Following what DNSPs use within their planning frameworks, the customer export curtailment value (CECV) is a time-varying cost that captures the detriment to customers and the market when DER exports are curtailed, and it is published by the AER [59].

Based on this, Figure 3-16 shows the parametric cost functions for all scenarios of curtailment, considering only the inclusion of solar units, while Figure 3-17 does so considering only wind units. Both these results follow the proactive planning already mentioned previously. The option of active network management can have a huge impact on investment decisions, particularly in the temporality of investments.

As curtailment constraints are relaxed, network reinforcements are delayed to further levels of DER within the parametrisation, that is greater adoptions of DER. For instance, if we compare the case with no curtailment (*maximum level of exports*) with the case where we can curtail up to 15%, both investment cost functions diverge after 8 MW of connected DER but converge again at around 15 MW. Thus, a more active management of distribution network can delay investments in network reinforcements (which is a lump investment option) through more granular investments, supporting the adoption in of DER in between 8 and 15 MW for this example. The same behaviour can be seen after 15 MW until 22 MW, and between other scenarios of maximum curtailment allowed.

Perhaps the main difference between solar and wind DER adoption, although wind requires slightly more investments in infrastructure across the parametrisation, relies on the scenario where curtailment is valued at the CECV. In this sense, because wind is more available throughout the day than solar, there are more chances for curtailment to be penalised and thus, enhancing the capacity of the network is cost-effective after 15 MW rather than after 18 MW as in the solar case.

Figure 3-16: Parametric investment cost function when connecting additional DER, only solar units

Figure 3-17: Parametric investment cost function when connecting additional DER, only wind units

Therefore, although CECV could represent a good proxy for the purpose of planning distribution networks, the optimal level of curtailment would be optimally determined when coordinating transmission and distribution planning and thus, it might be cost-effective from a whole system perspective to either have the possibility of fully using DER (maximum exports, no curtailment) or consider some level of curtailment within the parametric investment cost functions, instead of the "fixed" level of curtailment that results from distribution planning using CECV.

Moreover, these infrastructure investment costs can be further reduced when complementing both solar and wind resources, as shown in Figure 3-18. This highlights the importance of jointly planning distribution networks with DER integration, as it identifies where is best to connect and what resources to solve local problems, take advantage of hosting capacity, and reduce investments.

Figure 3-18: Parametric investment cost function when connecting additional DER, solar and wind units optimally allocated

These aspects are part of the essence of integrated planning frameworks where trade-offs between transmission and distribution investments are captured. Therefore, DNPSs could build multiple scenarios like this, where network reinforcements, and perhaps additional infrastructure such as reactive compensation, are displaced until further levels of DER adoption depending on the level of curtailment active distribution networks are planned for. This would build a convex space limited by these parametric investment cost functions, allowing to take better decisions on when to enhance distribution networks, and the optimal level of curtailment resulting from an integrated planning approach.

At the same time, we can visualise the operational flexibility for each of these scenarios. Figure 3-19 presents the NOEs of each curtailment scenario, considering a single snapshot of peak of DER generation, for levels of DER adoption of 12 MW, 18 MW and 26 MW, as investment costs differ for these adoptions. From this figure is clear that the maximum active power flexibility is reached when the network is planned to operate with no curtailment as the network is enhanced through reinforcements to fully export DER, while in the other cases, NOEs increase on the reactive power plane due to investments in reactive compensation that allow for active management of the network, enhancing its hosting capacity without investing in network reinforcements.

Moreover, as more DER is integrated in this network, NOEs increase in both active and reactive power flexibility due to portfolios of investments that combine network and non-network solutions (e.g., distributed storage, reactive compensation). Effectively, this means that the more DER capacity that is integrated in the system, DNSPs will have to shift towards managing the distribution network more actively and adopt different solutions to facilitate DER integration and unlock flexibility. In turn, building different scenarios that represent a parametric investment cost function, with the associated flexibility (e.g., NOEs), can be integrated in transmission planning to fully understand the most cost-effective way of developing power systems.

a) 12 MW of DER adoption

b) 18 MW of DER adoption

c) 26 MW of DER adoption

Figure 3-19: NOEs associated to each parametric cost function during solar hours

Moreover, the coordination of CER will also play a crucial role in the temporality and reduction of investments. Figure 3-20 presents parametric cost functions that include two scenarios of CER coordination, modelled as the inclusion of 1.5 MW and 3.0 MW of distributed

BESS, with the same duration AEMO models VPPs in the ISP (2.2 hours). Here, the flexibility from BESS allows for further reductions of investments as these resources can solve local problems while reducing the curtailment from distributed generation.

In particular, when the network is planned to operate with no curtailment, 3 MW of coordinated CER (jointly with reactive compensation) can delay network reinforcements from 12 MW up to 14 MW of DER integration. Furthermore, the same happens in between 14 MW and 22 MW, even when 1.5 MW of CER are coordinated. Additionally, once the network is planned for level of curtailment such as 15% allowed, the impact of CER coordination can be even greater, where investments are delayed in between 8 MW and 14 MW for both levels of CER coordination, and again between 18 MW and 24 MW. Furthermore, once further levels of curtailment are allowed, the investments needed do not change but rather how resources are managed. The flexibility from BESS allows for reductions in curtailment. Average reductions in curtailment are, 8% to 40% for the case of 30% curtialment, and 7% to 21% for the case with 100% curtailment, for both CER coordination levels respectively.

Figure 3-20: Impact of CER coordination when planning active distribution networks

Moreover, Figure 3-21 presents examples of how dynamic NOEs change based on the level of DER coordination. Here, for the scenario of 15% curtailment, all cases share the same investment cost, however, it can be seen the added flexibility from the additional 1.5 MW and 3 MW of distributed storage. Flexible limits increase for both active and reactive power.

a) Hour 15 of representative day

b) Hour 22 of representative day

Figure 3-21: NOEs for all levels of CER coordination, scenario with 15% curtailment at 26 MW of DER adoption

Finally, a sensitivity was carried out to understand the impact of demand growth (e.g., future electrification) when allocating DER, considering an increase in 100% of the peak demand. Particularly in this case, that is focused on the integration of distributed generation, the value associated to increased self-consumption from distribution networks could further reduce the need for investments in infrastructure, which may also impact how the transmission system is developed to integrate large-scale renewables.

The results from this sensitivity are depicted in Figure 3-20. Due to this increase, investments are needed from the first level of DER adoption within the parametrisation, particularly in reactive compensation to unlock active power and voltage constraints. Moreover, network reinforcements are delayed until 14 MW of DER adoption. This is because the amount of excess energy is reduced (due additional demand) and thus, increments in distributed generation help increasing self-consumption, which in turn delays investments that increase the exporting capacity. In this sense, it might be beneficial to develop additional DER for increasing the self-consumption of distribution networks, decentralising the power system, rather than developing large-scale generation, and transmission and distribution augmentations, to supply demand. Moreover, conclusions in terms of active network management are valid as well, the level of curtailment needed will greatly impact the planning of distribution networks.

Figure 3-22: Parametric investment cost function for demand when connecting additional DER

3.1.4.3 Subtransmission networks from the State of Victoria

From previous analyses it was shown that there are great benefits in proactively planning active distribution networks by optimally allocating additional resources, employing active network management, and coordinating CER. This mix of solutions unlocks flexibility from DER, or CER at lower voltages, which can provide benefits to the upstream network.

To analyse this, five 66 kV subtransmission network models, property of AusNet10, were employed. These are Cranbourne Terminal Station (CBTS), Glenrowan Terminal Station and Mount Beauty Terminal Station (GNTS-MBTS), South Morang Terminal Station (SMTS), East Rowville Terminal Station (ERTS), Thomastown Terminal Station (TTS), and Templestowe Terminal Station (TSTS) as depicted in the following figures.

[10] https://app.powerbi.com/view?r=eyJrIjoiNGI1YmUyZjctNTA1ZS00ZTJjLTg5ZTgtYjhkMWMwNWYyN2FhIiwidCI6ImEzOTRlNDFjLWNmOGQtNDU4ZS1hYzFiLWRkYWUxYWExNTYyOSIsImMiOjEwfQ%3D%3D

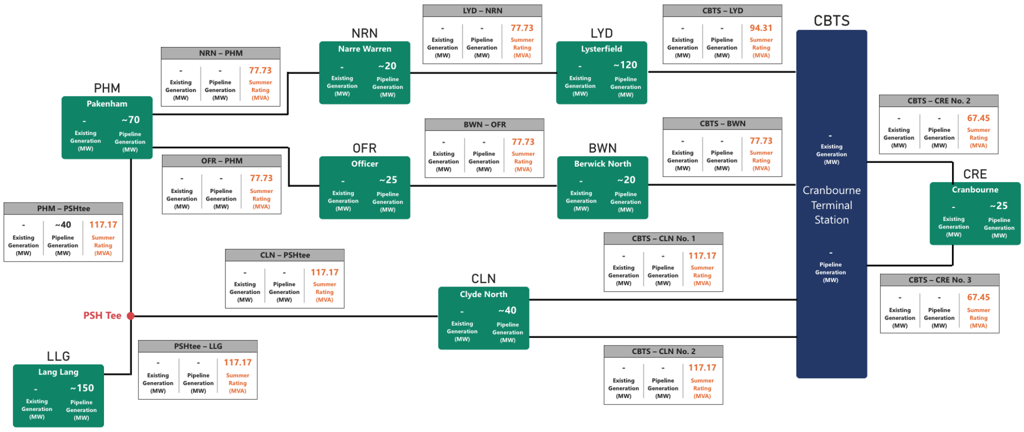


Figure 3-23: Cranbourne Terminal Station

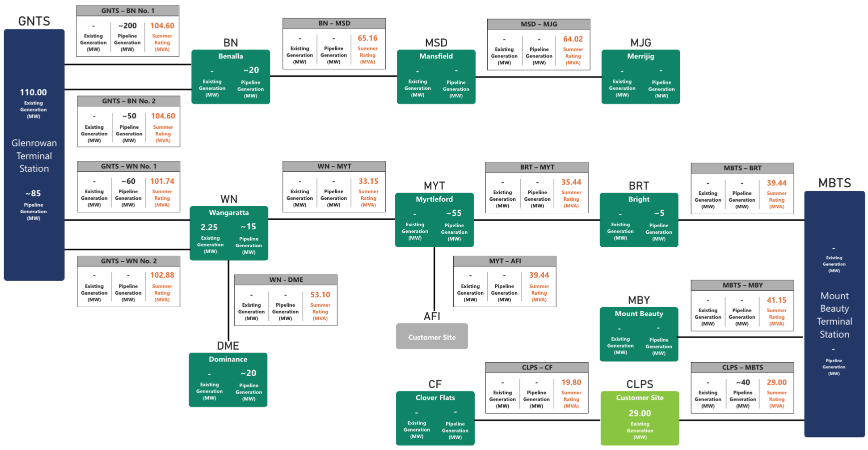


Figure 3-24: Glenrowan Terminal Station and Mount Beauty Terminal Station

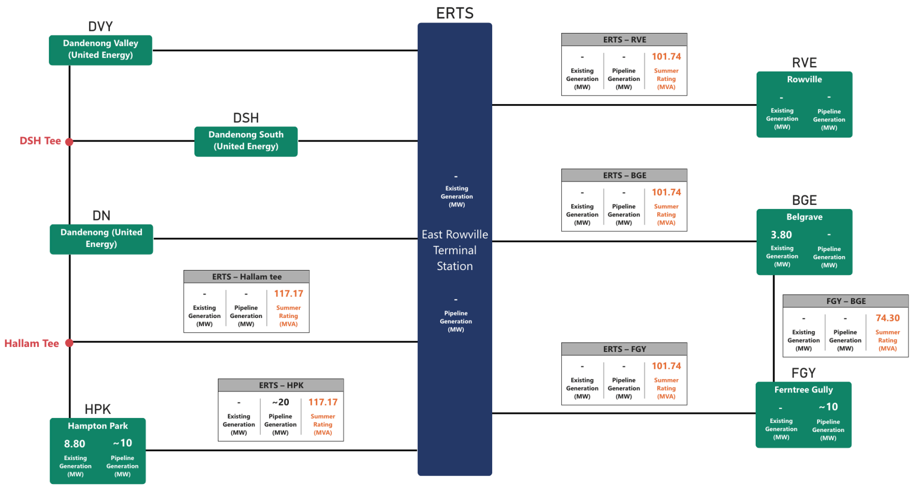


Figure 3-25: East Rowvile Terminal Station

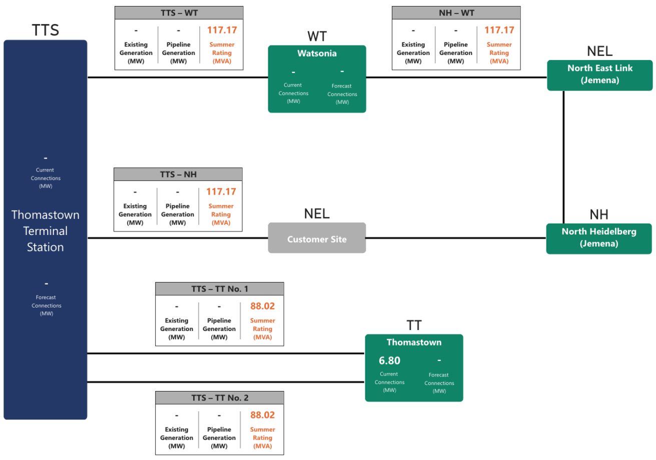


Figure 3-26: Thomastown Terminal Station

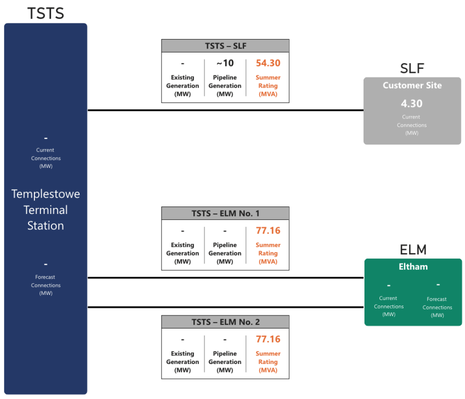


Figure 3-27: Templestowe Terminal Station

Each of these subtransmission networks are characterised with a rooftop PV capacity and a peak demand according to Table 3-1, where it is shown how much of Victoria's totals are represented by this set of networks, that is 17% for rooftop PV and 15% for peak demand. Moreover, each network is composed by a set of zone substations (nodes in the shown topologies), which are formed by a combination of *MV-LV typical feeders*, either urban, suburban, short rural and/or long rural. In this sense, CBTS, ERT and TTS lean towards urban compositions while GNTS-MBTS and TSTS towards rural networks.

Table 3-1: Rooftop PV capacity and peak demand, based on 2024

Additionally, to model the uptake of DER we used inputs and assumptions developed by the project Enhanced System Planning from C4NET, particularly work package 2.10 [60]. The projections used in that project are based on the State of Victoria within the Step-Change scenario of the ISP 2024. Here, demand and CER profiles were constructed with a bottom-up approach encompassing different network types (e.g., urban, rural), locations, seasons, and technologies, finding time-varying profiles for residential and commercial loads, and CER such as household batteries, EVs, domestic hot water (DHW), and heating and cooling. Particularly, the construction of EVs profile considered input data for battery size, charger capacity, charging patterns, arriving/departing times and commuting distance using the tool developed in [61]. Moreover, DHW and heating/cooling profiles are significantly influenced by location, network type, and season, aspects that are captured by the tool developed in [62], and assuming 50% electrification of cooling and 30% of heating in 2023 dwellings.

Thus, Figure 3-28Figure 3-28 and Figure 3-29 presents the composition for five representative days of the final aggregated energy profile for Victoria in 2040 and 2050. The blue area represents household (BESS), the only technology discharging power to the system. The red area indicates DHW demand, and orange represents heating/cooling demand. DHW energy requirements are comparable to heating/cooling only during shoulder and summer average days. In contrast, heating/cooling demand significantly exceeds DHW demand during winter and summer peak days. The plot also includes commercial loads (purple), residential loads (yellow), and EV demand (light teal) at the top of the figure. Furthermore, Figure 3-30 shows the aggregated demand profile and the total PV generation from distribution networks for the State of Victoria, where the operation of batteries is not included.

Figure 3-28 Aggregated profiles 2040

Figure 3-29 Aggregated profiles 2050

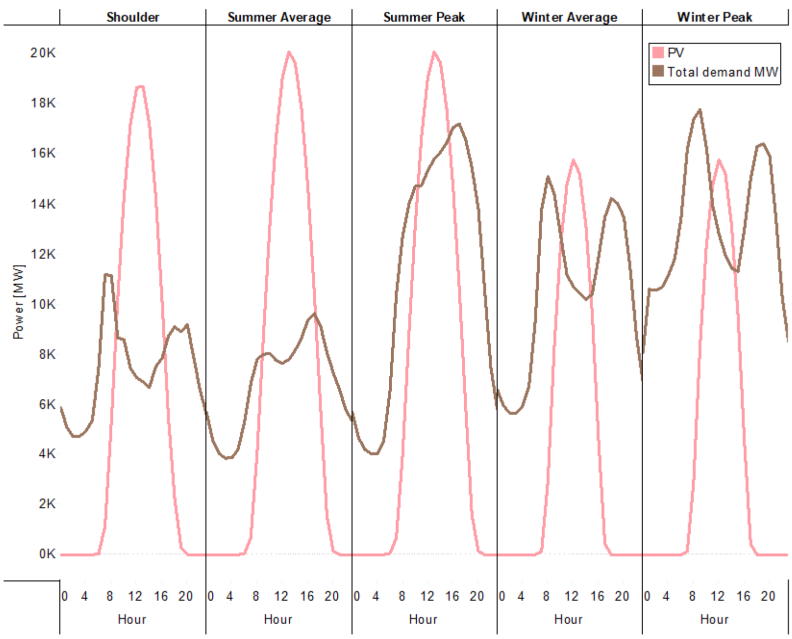


Figure 3-30 Aggregated profile and distributed PV generation

Under these assumptions we allocated a demand and CER profiles on the networks presented previously, depending on their composition in terms of network types (e.g., urban, rural), locations, and CER technologies. Thus, we assess the impact of CER coordination when planning subtransmission networks CBTS, GNTS-MBTS, TSTS, TTS, and ERTS.

Investment cost functions were computed for 0%, 25%, 50%, and 100% of CER coordination, accounting for the capital cost of coordination infrastructure. These results are shown in Figure 3-31 and Figure 3-32 considering projections of CER for years 2040 and 2050 respectively. Here, CER coordination has a huge impact on how subtransmission networks are planned, and when comparing the 0% and 100% CER coordination, total annual investments in infrastructure are reduced on average 50% for CBTS, 72% for GNTS-MBTS, 90% for TSTS, 48% for TTS, and 45% for ERTS, suggesting that rural networks tend to see more benefits from CER coordination (e.g., longer networks that require more compensation, meaning more investments). Such reductions come from the added flexibility from CER coordination, which allows for solving several local problems that defer most of the initial investments, but these benefits will depend on the characteristics of the network (e.g., peak load, composition, topology, etc.) and its hosting capacity.

Figure 3-31: Investment cost functions for subtransmission networks for 2040

Figure 3-32: Investment cost functions for subtransmission networks for 2050

Moreover, we computed equivalent models for each network and assessed how the active power exchanged between each subtransmission network, and the upstream network would change due CER coordination. To do this, we computed the equivalent models of each pair of CER adoption and investments, where Figure 3-33 and Figure 3-34 show some examples of how the flexibility limits of active power are dynamically extended by the action of CER coordination and proper investment decisions.

a) CBTS, 0% CER coordination, shoulder day

b) CBTS, 100% CER coordination, shoulder day

c) GNTS-MBTS, 0% CER coordination, summer peak

d) GNTS-MBTS,100% CER coordination, summer peak

Figure 3-33: Dynamic active power flexibility range, reference year 2040 *a) CBTS, 0% CER coordination, winter peak* *b) CBTS, 100% CER coordination, shoulder day*

c) TSTS, 0% CER coordination, summer peak *d) TSTS,100% CER coordination, summer peak*

Figure 3-34: Dynamic active power flexibility range, reference year 2050

Then, we simulated OPFs with the objective of maximising the self-consumption for these networks, represented by their equivalent model. This is depicted in Figure 3-35 for networks CBTS, ERTS, GNTS-MBTS, and TTS, where the management of CER, and particularly storage from batteries and EVs, allows for both reducing peak demand and increasing the net-demand during solar hours. In addition, schemes of demand-response schemes that would come from DHW, and heating/cooling demands could also be employed to reduce load at different times as is the case in GNTS-MBTS.

a) CBTS *b) ERTS*

c) TSTS

d) TTS

Figure 3-35: Self-consumption operation of year 2050 from equivalent model associated to parametric cost functions for networks CBTS, ERTS, ERTS, TSTS, and TTS

Finally, from these cost functions is possible to find the aggregated investment cost function for the whole State of Victoria. To do this, we assume the same levels of CER coordination, that is 0%, 25%, 50%, and 100%, meaning that we can simply aggregate the cost functions of these networks as the coordination level increases accordingly in them. Nevertheless, based on their composition, CBTS, ERTS, and TTS are networks associated to urban locations while GNTS-MBTS and TSTS to rural locations, and based on the studies carried out in [60], the composition of networks in Victoria correspond approximately to 85% urban and 15% of rural.

Therefore, we can find the result depicted in Figure 3-36. This information could be produced by DNPSs and communicated to AEMO, facilitating the coordination between transmission and distribution planning. Furthermore, as stated before, this parametric approach works against any scenario of DER adoption but particularly in this case, we assessed the benefits that come from CER coordination for the State of Victoria, representing approximately 50% for both 2040 and 2050.

Figure 3-36: Victoria's aggregated parametric investment cost function for levels of CER coordination

3.2 Integrated planning

This section focuses on providing a brief description of the theoretical background of the integrated expansion planning model used for the development of this project, with a particular emphasis on the modelling details behind the inclusion of the planning of active distribution systems as "flexible investment option".

The aim of the proposed methodology is to precompute an investment cost function, parametrised against DER adoption, which can include CER coordination, or any relevant planning parameter (e.g., assessments on additional DER), coupled with an equivalent model that captures the operational flexibility of the distribution system for each planning scenario (i.e., parametrisation).

Thus, as illustrated in Figure 3-37, this methodology would be applied in a bottom-up fashion, that is, planning low-voltage (LV) networks to produce investment and operational information that depend on, for instance, adoption and/or coordination of CER. This would be communicated into the planning of medium-voltage (MV) networks, where LV networks would be represented as an equivalent model (e.g., aggregated resources) with associated investment costs. The same process would be repeated for planning the high-voltage (HV) networks, aggregating MV and LV networks, which are represented as an equivalent model and investment costs.

Therefore, following these steps, the whole distribution system can be represented with a parametric investment cost function, and the corresponding equivalent model, integrating them directly in a single optimisation step as an additional "flexible investment option" within a transmission planning problem, comparing them to large-scale investments such as transmission augmentations and storage.

Figure 3-37: Bottom-up application of distribution system planning methodology, where resources are aggregated from LV to HV, and then communicated to the system planner entity for national planning purposes.

Based on this, distribution planners (e.g., DNSPs) can produce this information through their own tools and communicate it to the central planner, like AEMO in the Australian case. In turn, AEMO could capture distribution system’s investment costs, network limitations, and operational flexibility, for each subregion of the NEM in a single optimisation step (additional variables and constraints within ISP modelling) with the information produced by DNSPs.

In this context, the core of the modelling used in this project is based on the planning tool developed by the University of Melbourne in Stage 2 and 3 of Topic 4 – Planning of the CSIRO-GPST roadmap, as depicted in Figure 3-38. This model is based on the minimisation of investment and operational costs for a planning horizon, and in addition to the transmission side, it includes the costs associated to distribution planning through the proposed methodology, that is, an equivalent model with associated investment costs to support levels of DER or planning scenarios. In this sense, this parametric structure to represent distribution systems serves as “future development options”, allowing for decision-making from a centralised/coordinated whole-system perspective.

Moreover, the system operational component of the total costs includes operational costs of all generation units and demand-response bands based on the 2024 ISP, and the cost of not serving energy to the customers at any given period, which in the context of this study is valued at the current market price cap for the NEM.

Figure 3-38: General structure of the expansion planning problem

Furthermore, the mathematical formulation is detailed in the Appendix C of this project, but broadly speaking the model imposes a set of constraints for investment and operational decisions, which include:

- *Transmission investment constraints*: these include the so-called non-anticipativity constraints. These guarantee that an investment made in a certain year remains present in the system in the subsequent years.
- *Distribution investment constraints*: these guarantee that only one future path (DER capacity) can be optimally selected for a given distribution system representation, which could be one per sub-region within the ISP
- *Power system constraints*: these correspond to all the constraints associated to power system operation, including energy balances, reserve provision, power flow, transmission limits, etc.
- *Unit-commitment constraints*: the operation of conventional units in the system is bound by their technical characteristics, for instance, ramping limits, minimum stable generation, start-up times, etc.
- *Distribution operational capabilities*: these are associated with managing all the components of the equivalent model, which is defined for all representative periods used in the planning problem. That is, renewable generation curtailment, storage operation including state-of-charge constraint, demand response capabilities, and the coupling with the transmission system.

Although this integrated planning approach shares similar principles with the proposed methodology by AEMO, the proposed methodology allows for assessing the impact of active network management, non-networks solutions within distribution networks, and the impact of CER coordination, which could reduce investments in traditional distribution network reinforcements, while also proposing a novel method for aggregating distributed resources while accounting for network constraints. In addition, it allows for decision-making over additional DER, considering distribution networks as investment opportunities rather than infrastructure to supports expected adoption of CER.

Moreover, to properly represent distribution networks in each sub-region of the ISP, a proper understanding of the constraints and limitations of distribution networks is needed and thus, analyses conducted in this section will show the potential of including distribution system in an integrated transmission-distribution planning, and the applicability of the proposed methodology, rather than an accurate quantification of real-world benefits.

Nevertheless, AEMO proposed to collaborate with DNSPs using two approaches. The **data asset approach** calculates the volume of CER output being enabled for each distribution data asset, using DNSP-provided network limits and disaggregated AEMO forecasts for CER uptake and consumer load, before being aggregated back up to the sub-regional reference node. Under the **detailed modelling approach**, DNSPs would perform their own analyses using AEMO's forecasts, enabling more accurate estimations of CER integration and network constraints [17].

3.2.1 Integration of active distribution system planning into the NEM

To understand how this methodology can be applied, aiming at real-world implementations we proposed a case study that includes active distribution systems, represented by the proposed methodology, considering a small representation of the NEM for the State of New South Wales, as it has 4 sub-regions and multiple transmission augmentation options. The analysis is based on the inputs and assumptions of the Step-change scenario of the ISP 2024 [63]. This includes demand and generation traces, as well as decommission of units aligned to the decarbonisation pathway, investment options and costs. Investment-related cash flows (annuities, discounting, etc.) are calculated using a 10% discount rate. The model allows including investments in real transmission options considered in the ISP 2024, where we consider the augmentation flow paths and their investment costs [56].

Moreover, to represent the distribution system participation, we use the subtransmission network CBTS as proxies, whose information was presented in section 3.1.4.3. This network is characterised by a 10-node topology, peak demand of 475 MW and rooftop PV adoption of

345 MW. For investments in network reinforcements are considered 11,000 $/km/MVA which come from a Regulatory Investment Test for one of AusNet's networks[11].

Then, to represent the subregions NSW, we proportionally allocated the expected CER, demand, and the associated traces, based on the current characteristics of the selected representative Victorian network. In this sense, each subregion is modelled using a representative CBTS network that are design with the same peak demand but differs in CER and demand traces, which are aligned with the specific expectations for that subregion. As a result, each network can be scaled to reflect regional CER adoption using a numerical factor. Based on this method, the equivalent number of CBTS networks representing each region are approximately: 2.3 in NNSW, 3.7 in CNSW, 3.4 in SNSW, and 24.7 in SNW.

In this vein, it was proposed to analyse the impact of CER coordination (e.g., curtailment of rooftop PV, operation of distributed storage in the form of virtual power plant, and demand response schemes) in the planning of distribution systems, and their inclusion in this transmission planning problem. It is worth noting that this problem is solved for year 2035 as reference for adoption of resources, costs, and expected generation, taking investment decisions over transmission and the level of CER coordination for sub-regions NNSW, CNSW, and SNW, parametrising for 0%, 50%, and 100% of the expected adoption by 2035. Moreover, the case with 0% coordination is planned to maximise exports, meaning that is prepared for not curtailing distributed PV.

As presented in Figure 3-39, by coordinating only 50% of CER, investment costs in distribution systems can be hugely reduced. The core of this 50% coordination is associated to the operation of distributed storage expected in each sub-region (optimal decision from planning the network), which serves as the most important source of flexibility to alleviate constraints within distribution systems and also reduce curtailment from distributed solar. Moreover, as the level of coordination is increased, additional flexibility is gained in the form of and demand response, nevertheless these do not change the investment costs when planning the network.

[11] AusNet. Regulatory Investment Tests. Available at: https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test

Figure 3-39: Case study on DER coordination for New South Wales

Once this information is passed on to the transmission planning problem, it is possible to decide on CER coordination. Thus, if we compare this case with one where 0% coordination is fixed as decision variable, we **find a 26% total cost reduction** mainly due to the **deferral of 2 transmission augmentation options that connect CNSW-SNSW and CNSW-SNW**, which translates into **3.4 GW of avoided capacity**, but also to the reduction in distribution network investment costs from CER coordination, aspect that is currently not quantified by the ISP yet. At the same time, **curtailment is also reduced in 7%.** These are promising results, but they only represent a portion of the benefits that could be unlocked if this methodology is applied to the whole NEM and planning horizon currently considered in the ISP.

Then, to show the scalability of this methodology, the same analysis was extended to include distribution representations of Victoria, Tasmania, and Central South Australia as depicted in Figure 3-40. All distribution planning representations present the same behaviour, as soon as we can control CER, investment costs are hugely reduced, but again, these results are subject to change as soon as the true limitations of each sub-region are considered. From this case study, when coordinating CER, total costs are reduced in **28%** when compared against the case with 0% CER coordination. Like previously, this comes from avoiding **3 transmission projects** that would link **CNSW-SNW, NNSW-NNEM, and CNSW-SNW, a total of 6.4 GW, but also reductions in distribution investment costs.**

Figure 3-40: Case study on DER coordination for New South Wales, Victoria, Tasmania, and South Australia

Moreover, since there are many benefits from coordinating CER, and particularly distributed storage. Therefore, it is worth analysing if additional investments within distribution networks would have further benefits. Based on this, we computed investment cost functions for subregions NNSW, CNSW, SNW, SNSW, VIC, TAS, and CSA but allocating additional DER in the form of distributed storage. Thus, on top of the infrastructure annual investment cost, we included the annuity of these additional resources, and this is the reason of the increasing behaviour by the investment cost functions presented in Figure 3-41.

Figure 3-41: Investment cost function for increasing levels of distributed storage

In this case, the initial DER adoption within the parametrisation corresponds to 100% of coordinated CER, e.g., curtailment, VPPs, and demand response, while we increase this adoption with additional storage of 2 hours of duration. Then, the integrated planning problem finds the optimal solution as keep on coordinating 100% of the expected CER and thus additional storage is not needed. This happens mainly due to the great large-scale storage capacity expected in the NEM by 2035, reaching 21.4 GW for the step-change scenario, that include projects such as Snowy 2.0, and Borumba, which suggests that efforts should be towards properly reaching the expected levels of CER and coordinate it.

Moreover, this increase in flexibility allows for a more active management of distribution networks, modelled with an equivalent model, which translates into leveraging existing and expected resources more optimally. Thus, Figure 3-42 compares the active power exchange between the NEM and the subregions SNW and VIC, for a representative week for 0% (non-flexible, that is fixed net-load profile) and 100% (flexible) of CER coordination. Coordinating CER, particularly storage allows for a reduction of peak demand but also to increase the net-load during peak hours of solar generation, which in turn allows for reductions in DER curtailment. All this unlocked flexibility allows to displace transmission augmentations.

Figure 3-42: Power exchange between SNW, and VIC, with the NEM, for one representative week

In this sense, additional storage within distribution could be valuable if we were deciding on the total amount of storage needed (no existing nor expected storage from ISP). In this case, there would an optimal mix between large- and small-scale storage. Moreover, this additional distributed storage could also open possibilities for connecting additional distributed generation, resembling the case studies presented in section 3.1.4. Nevertheless, such comparison could be unfair if there is no trade-off with large-scale renewables.

Furthermore, another aspect that is worth assessing is the inclusion of high-impact, low probability (HILP) events. Extreme events are incorporated as distinct representative periods within the year of analysis, weighted by their likelihood of occurrence. Input data is modified to reflect conditions such as increased demand, reduced renewable generation, or alterations in the system's architecture due to different infrastructure outages. For this case study, we analyse the loss of one interconnector between CNSW and SNW with capacity 4.7 GW as depicted in Figure 3-43.

Figure 3-43: HILP event modelled with the integration of active distribution networks

Although the extreme event, the model still optimally determines that no additional distributed storage is needed, and that CER coordination is the optimal path to develop the system. As CER coordination can make consumption patterns more efficient, it allows for deferring transmission expansion in 3.4 GW in this case, which was an additional investment decision to connect CNSW to NNSW used to import more energy from the north part of the NEM and support the contingency. Moreover, if we consider large-scale storage as an investment option, 300 MW in SNW are part of the portfolio of investments, further reducing operational costs.

It is worth mentioning that one of the more relevant results in Stage 3 of Topic 4 was that incorporating extreme events into the planning problem reveals the need for anticipatory reinforcements in the transmission network, and the value of CER coordination when mitigating the impact during these extreme periods. Nevertheless, this aspect was not explored because we focused on the methodological integration of distribution networks planning. Further work could extend this into coupling parametric cost functions for multiple decision nodes so that lead-time is incorporated, properly assessing transmission augmentations.

3.2.2 Victorian representation within integrated planning

A final case study was conducted by representing the State of Victoria with all subtransmission networks used before in section 3.1.4.3, as depicted in Figure 3-44. We used the same inputs and assumptions as before, meaning that CER coordination in this case refers to distributed storage, EVs (modelled as a battery with time-varying storage limits), DHW, and load reduction from heating and cooling demands. Thus, even though we move away from the ISP in terms of modelling the representation for Victoria, the rest of the subregions keep the same CER modelling in place, that is a VPP with around 2.2 hours of duration, and load shedding schemes. We compare the case where storage from CER is not coordinated, to a case where the optimal level of coordination is found. Since we only represent Victoria, the rest of the subregions include the expected CER from the Step-change scenario 2040.

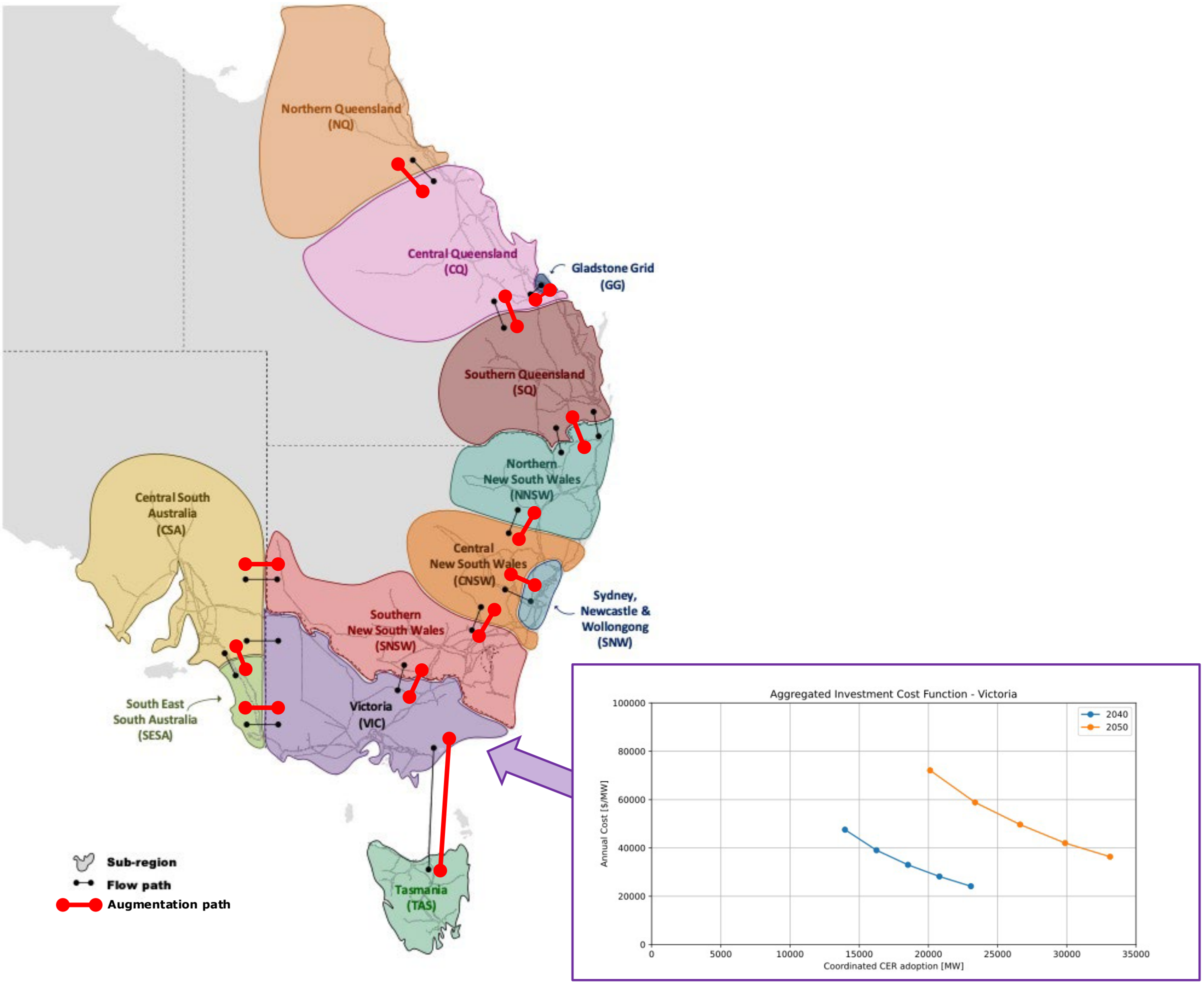


Figure 3-44: Representation of Victoria through parametric cost functions within the NEM power system

When optimally deciding on the level of CER coordination, the model decides to unlock 100% of coordination in the State of Victoria. In addition, if we compare this solution to that of fixing 0% CER coordination, there are no changes in the total transmission augmentations, both cases requiring 24 GW of additional capacity. Nevertheless, there is a reduction in annual investment and operational costs of 10.8%, and total curtailment (transmission and distribution assets) in 5.4% due having 100% CER coordination. Again, these results consider only the investment costs of the distribution side in Victoria, while the other sub-regions have CER coordination at zero cost.

Moreover, Figure 3-45, presents a comparison of the operation from the equivalent model representing Victoria, between the case where Victoria is a distribution network with no CER coordination, where curtailment is not allowed, and the optimal case regarding CER coordination. It is possible to see the impact that CER has in the consumption pattern, allowing for reducing the peak demand but also increasing the load during peak solar generation.

Figure 3-45: Operation of State of Victoria, represented by the equivalent model, 2040

Then, we repeated the analyses for the year 2050. In this case, when comparing the case with 0% CER coordination to the one where the CER coordination level is optimally decided, there is a reduction in total costs is 20%, where the main part of it comes from operational costs, that are reduced in 20.2%, while investment costs are reduced 1.5%. The latter reduction is due to the deferral of 1 GW of transmission augmentations.

Moreover, in operational terms, curtailment in 4.5% when the 100% of CER coordination. Thus, Figure 3-46 presents a comparison of the operation from the equivalent model representing Victoria. It can be seen again how the distribution network has the potential to reduce its peak demand while reducing curtailment during solar hours.

Figure 3-46: Operation of State of Victoria, represented by the equivalent model, 2050

Finally, although it has been shown the applicability of the proposed methodology, to find better results in terms of cost reductions, there’s a need to understand the limitations and investments needed within distribution networks across all levels, that is LV, MV, and HV, but also across all subregions. This is truly important as the flexibility from DER can be overestimated as some of the resources are CER, such as EVs, DHW, distributed batteries, that could be constrained by limitations within MV-LV networks unless, of course, proper investments are made, but also by customer preferences to participate in the provision of services to make consumption patterns more efficient. Nevertheless, it has been shown, through the scenarios to construct the parametrisation, that the most benefits do come when 100% of CER is coordinated, suggesting the need for incentivising this development.

However, there is a trade-off between distribution investments and the provision of local services by CER, and this balance would depend heavily on the objective function of the distribution planning approach, which is accounted for by the proposed methodology. For instance, at the extreme, DNSPs could present future paths that fully exploit these resources upstream, meaning additional investments so that CER can be fully coordinated by AEMO, and could open the possibility for considering distribution networks as investment options when planning power systems at a national level, such as within the ISP. Another approach would be to plan distribution networks by just minimising costs, where CER coordination would help reducing investments for DNSPs, but the amount of flexibility that these resources could provide upstream would be limited, nevertheless benefits would come regardless due to more efficient consumption patterns in a decentralised manner.

3.3 Key insights

This section studied the impact and value of the integration of active distribution systems in transmission expansion planning. To make this efficient, a methodology was proposed based on distributed decision-making so that any DNSP can produce and share information while keeping their current roles and tools. This approach consists on an investment and operational framework that seeks to represent the planning of active distribution networks and their management within transmission planning frameworks. The studies that were conducted made it possible to assess how DER flexibility impacts investment decisions within distribution and transmission networks and operational costs. The main insights obtained through this section can be summarised as follows:

- ***I. The need for proactively planning the active management of distribution networks:*** The construction of parametric investment cost functions allows to quantify the investments needed in distribution networks to support levels of DER adoption, which can include CER coordination, or any future scenario envisaged by stakeholders like AEMO or DNSPs. Nevertheless, there are benefits when coordinating the investments in distribution with the connection and integration of DER or CER, suggesting that DNSPs could adopt these practices This information can be produced at different levels of distribution systems and should be employed as a bottom-up approach.
- ***II. The equivalent model is a suitable approach for characterising the flexibility of DER technologies and distribution network limitations:*** To aggregate the flexibility that is unlocked in each point within the parametric investment cost function, the

computation of an equivalent model was proposed in this project. This framework is based in NOEs, dynamically calculated for each point consisting of a pair of DER adoption (x-axis) and investment costs (y-axis). It captures accurately the maximum limits for active power of distribution networks by representing them with a generator, flexible load, and a storage component. However, some limitations comprise the representation of reactive power in the equivalent modelling approach, and the fact that the flexible limits also depend on the voltage at the interface. Nevertheless, DC power flow (typical model for transmission) do not consider reactive power and variation in voltages and thus, it will be important for analyses that do need these relationships.

III. ***Active network management is cost-effective against traditional distribution network augmentation:*** Investment options such as distributed storage, reactive compensation, curtailment, and coordination of CER can unlock huge value when planning distribution networks. However, there is a threshold after which network reinforcements are needed to support additional resources. Moreover, it will be crucial to understand and regulate the roles of DSNPs to consider all these alternatives, and how DER integration can be jointly planned with distribution networks to find more cost-effective solutions from a whole-system perspective.

IV. ***Distribution systems planning can be represented within transmission expansion planning frameworks:*** The proposed methodology allows for quantifying investment costs to support DER from a bottom-up approach and allows for reducing the modelling requirements of active distribution systems in transmission planning, capturing network limitations and DER's active power dynamic flexibility through an equivalent model. Thus, they can be efficiently integrated in transmission expansion planning frameworks, such as the ISP, allowing to enhance the coordination between transmission and distribution within decision-making for future power systems. This has huge potential for finding cost-effective developments by weighting in trade-offs between large- and small-scale resources.

V. ***Coordinated DER enables cost-effective demand growth management through increased self-consumption:*** As electricity demand grows due to electrification, actively managed DER (e.g., PV or wind + storage from coordinated CER) can help absorb this growth locally, delaying the need for grid capacity upgrades. Coordination ensures that energy generated and consumed within a local network is balanced efficiently, reducing imports, and minimising curtailment, leading to lower system costs.

VI. ***MV-LV constraints are crucial in evaluating CER integration potential:*** Although high-level models often simplify the representation of distribution networks, real-world integration depends on granular MV-LV considerations such as voltage stability, reverse power flow limits, and feeder headroom. Ignoring these leads to overestimated DER hosting capacity and underestimation of required grid support investments. Incorporating these details improves accuracy and ensures feasible CER integration outcomes.

VII. ***The coordination of DER brings great benefits to the planning and operation of the NEM:*** The coordination of DER has the potential to enhance overall system flexibility, leading to a decreased reliance on capital-intensive distribution and transmission infrastructure investments that could become stranded. Also, these resources provide flexibility that allows for optimally managing consumption patterns at the interface with the NEM, reduce grid congestion, and minimising DER energy curtailment, reducing operational costs as result. Importantly, case studies presented in this project should mainly serve as proof of concepts.

4 Integrated planning of electricity-hydrogen hybrid energy hubs and transmission

Hybrid electricity-hydrogen energy hubs emerge as a suitable option to enable the development of the H_2 industry considering the option to transform and store different energy carriers at the same location. Proper modelling and planning of this sector-coupling hub infrastructure with shared connection assets is thus important for the future development of the whole energy system in Australia. In this work, a modular and scalable framework for the design and assessment of hybrid energy hubs is developed and integrated with transmission planning. Besides, adequate level of network resolution is determined to perform integrated planning of hybrid energy hubs and transmission infrastructure while maintaining computational tractability. Moreover, the analysis quantifies the impact of hybrid hubs on transmission investment needs and explores how their integration with H_2 transmission infrastructure influences investment portfolios in resilience studies.

4.1 Methodology for design of electricity-hydrogen hybrid energy hubs

An illustrative comparison of a bus-level and hub-level investment approach is shown in Figure 4-1. The proposed methodology focuses on optimising the design of electricity-hydrogen hybrid energy hubs by potentially reducing capacity of connection assets through investment coupling. In traditional bus-level (independent investment) planning, each investment component, such as wind turbines, solar PV, batteries, and electrolysers, requires its own dedicated HV substation. These substations often include MV/HV transformers, switchyard, reactive power compensation plant, and other associated equipment, along with a dedicated feeder to connect to the grid.

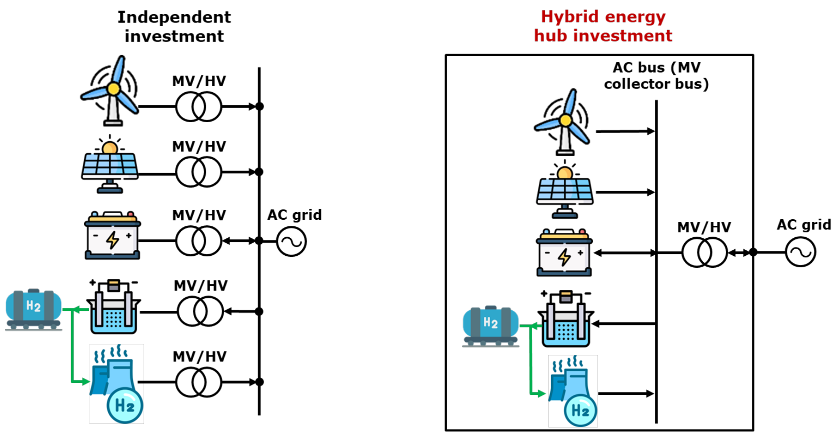


Figure 4-1: Comparison of bus-level (left) and hub-level (right) investment configurations.

In contrast, in a hub-level planning approach, these generation, storage, and H_2 production components are co-located and integrated, allowing energy to be collected at a shared MV bus within the hub. Instead of using multiple individual MV/HV transformers in separate HV substations, the hybrid energy hub enables a MV/HV step-up/down process through shared connection assets to match the voltage for grid connection. This leverages the diversity across different technologies within a hub, reducing the total capacity of connection assets. This approach not only lowers investment costs but also improves efficiency.

As defined in [64], each investment option comprises both a build cost and a connection cost. The build cost includes equipment costs (e.g., PV modules, wind turbines, cables, power converters) and installation costs. The connection cost accounts for grid connection feeder, HV substation and their installation costs. As illustrated in Figure 4-2, in the bus-level planning approach, the total investment costs for all component options are the sum of the individual build costs and connection costs for each component. In contrast, the hub-level planning approach aggregates the build costs of all component options within the hub and applies a single connection cost for the entire hub. Additionally, REZ network expansion to transport more VRE within REZs to the existing grid and the associated costs are considered for both bus-level and hub-level planning when power flow exceeds REZ transmission network limit stipulated in AEMO’s 2024 ISP.

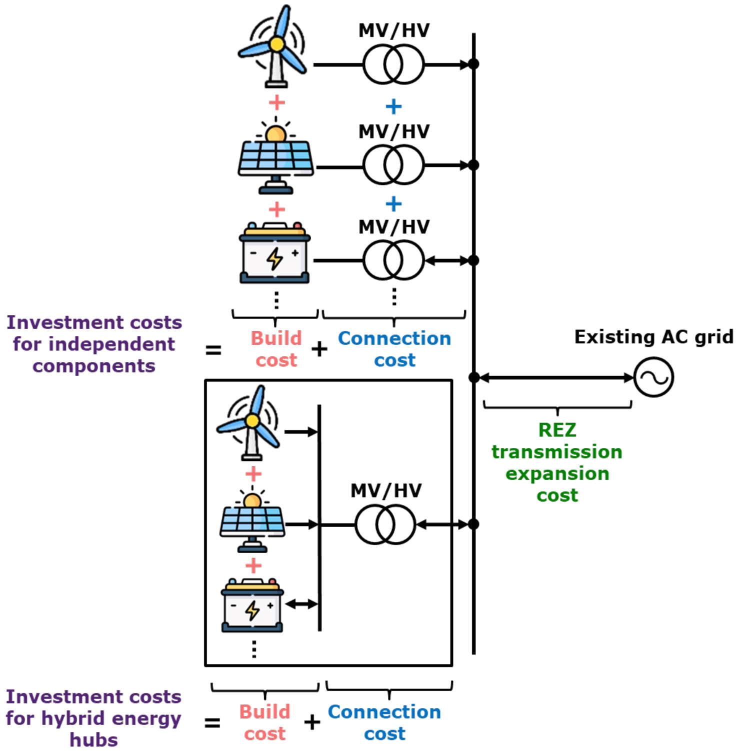


Figure 4-2: Illustrative cost representation for bus-level independent investment, hub-level integrated investment, and REZ transmission expansion.

The details of the developed energy hub model can be referred to [65]. A high-level explanation of the modelling of an energy hub connected to existing grid is provided as follows.

$$\begin{aligned} P_{ptg,hub,t}/\eta_{ptg} + P_{BESS,hub,t}^{charge} + f_{export,hub,t}/\eta_{tx} \\ = P_{wind,hub,t}\eta_{wind} + P_{solar,hub,t}\eta_{solar} + P_{HPG,hub,t}\eta_{HPG} + P_{BESS,hub,t}^{discharge} \\ + f_{import,hub,t}\eta_{tx} \end{aligned} \tag{4-1}$$

$$\begin{aligned} P_{ptg,bus,t}/\eta_{ptg}\eta_{tx} + P_{BESS,bus,t}^{charge} + f_{import,hub,t} + f_{export,bus,t} \\ = P_{wind,bus,t}\eta_{wind}\eta_{tx} + P_{solar,bus,t}\eta_{solar}\eta_{tx} + P_{HPG,bus,t}\eta_{HPG}\eta_{tx} + P_{BESS,bus,t}^{discharge} \\ + f_{export,hub,t} + f_{import,bus,t} \end{aligned} \tag{4-2}$$

$$P_{BESS,hub,t}^{charge} \leq M z_{BESS,hub,t} \tag{4-3}$$

$$P_{BESS,hub,t}^{discharge} \leq M(1 - z_{BESS,hub,t}) \tag{4-4}$$

$$P_{BESS,bus,t}^{charge} \leq M z_{BESS,bus,t} \tag{4-5}$$

$$P_{BESS,bus,t}^{discharge} \leq M(1 - z_{BESS,bus,t}) \tag{4-6}$$

$$E_{BESS,hub,t} = E_{BESS,hub,t-1} + (P_{BESS,hub,t}^{charge}\eta_{BESS} - \frac{P_{BESS,hub,t}^{discharge}}{\eta_{BESS}})\Delta t \tag{4-7}$$

$$E_{BESS,bus,t} = E_{BESS,bus,t-1} + (P_{BESS,hub,t}^{charge}\eta_{BESS}\eta_{tx} - \frac{P_{BESS,hub,t}^{discharge}}{\eta_{BESS}\eta_{tx}})\Delta t \tag{4-8}$$

$$f_{import,hub,t} \leq M z_{connect,hub,t} \tag{4-9}$$

$$f_{export,hub,t} \leq M(1 - z_{connect,hub,t}) \tag{4-10}$$

$$f_{import,hub,t} \leq \bar{f}_{connect,hub} \tag{4-11}$$

$$f_{export,hub,t} \leq \bar{f}_{connect,hub} \tag{4-12}$$

$$f_{import,bus,t} \leq M z_{REZ,t} \tag{4-13}$$

$$f_{export,bus,t} \leq M(1 - z_{REZ,t}) \tag{4-14}$$

$$0 \leq \bar{f}_{REZ} \tag{4-15}$$

$$f_{import,bus,t} - f_{REZ}^{limit} \leq \bar{f}_{REZ} \tag{4-16}$$

$$f_{export,bus,t} - f_{REZ}^{limit} \leq \bar{f}_{REZ} \tag{4-17}$$

$$\begin{aligned} &P_{ptg,hub,t}, P_{BESS,hub,t}^{charge/discharge}, P_{wind,hub,t}, P_{solar,hub,t}, P_{HPG,hub,t} \\ &\quad \leq \bar{P}_{ptg,hub}, \bar{P}_{BESS,hub}, \bar{P}_{wind,hub}, \bar{P}_{solar,hub}, \bar{P}_{HPG,hub} \end{aligned} \tag{4-18}$$

$$\begin{aligned} &P_{ptg,bus,t}, P_{BESS,bus,t}^{charge/discharge}, P_{wind,bus,t}, P_{solar,bus,t}, P_{HPG,bus,t} \\ &\quad \leq \bar{P}_{ptg,bus}, \bar{P}_{BESS,bus}, \bar{P}_{wind,bus}, \bar{P}_{solar,bus}, \bar{P}_{HPG,bus} \end{aligned} \tag{4-19}$$

$$\begin{aligned} C_{component}^{inv} = {} & \bar{P}_{ptg,hub}C_{ptg}^{build} + \bar{P}_{BESS,hub}C_{BESS}^{build} + \bar{P}_{wind,hub}C_{wind}^{build} + \bar{P}_{solar,hub}C_{solar}^{build} \\ & + \bar{P}_{HPG,hub}C_{HPG}^{build} + \bar{f}_{connect,hub}C_{hub}^{connect} + \bar{P}_{ptg,bus}\left(C_{ptg}^{build} + C_{ptg}^{connect}\right) \\ & + \bar{P}_{BESS,bus}\left(C_{BESS}^{build} + C_{BESS}^{connect}\right) + \bar{P}_{wind,bus}\left(C_{wind}^{build} + C_{wind}^{connect}\right) \\ & + \bar{P}_{solar,bus}\left(C_{solar}^{build} + C_{solar}^{connect}\right) + \bar{P}_{HPG,bus}\left(C_{HPG}^{build} + C_{HPG}^{connect}\right) + \bar{f}_{REZ}C_{REZ}^{expand} \end{aligned} \tag{4-20}$$

Constraints (4-1) and (4-2) describe the power balance within a hub and at a bus, respectively. The power outputs of wind, solar, and H_2 gas turbine units within a hub and at bus are denoted by $P_{wind,hub,t}$, $P_{wind,bus,t}$, $P_{solar,hub,t}$, $P_{solar,bus,t}$, $P_{HPG,hub,t}$, and $P_{HPG,bus,t}$, respectively. The charging/discharging power of BESS and power consumption of electrolyser within a hub and at bus are denoted by $P_{BESS,hub,t}^{charge}$, $P_{BESS,hub,t}^{discharge}$, $P_{BESS,bus,t}^{charge}$, $P_{BESS,bus,t}^{discharge}$, $P_{ptg,hub,t}$, and $P_{ptg,bus,t}$, respectively. Binary variables $z_{BESS,hub,t}$ and $z_{BESS,bus,t}$ indicate the charging and discharging status of BESS, enforced using a large constant number M as defined in (4-3) to (4-6). The BESS energy state of charge is described in (4-7) and (4-8). The energy efficiency of wind, solar, H_2 gas turbine, BESS, electrolyser units, and HV/MV transformer are denoted by η_{solar}, η_{wind}, η_{HPG}, η_{BESS}, η_{ptg}, and η_{tx}. Power can be exchanged bidirectionally between the energy hub and the grid bus to which it is connected. Power exported from the hub to the bus and power imported from the bus to the hub are represented by $f_{export,hub,t}$ and $f_{import,hub,t}$. Additionally, power import to the bus from the existing grid and power export from the bus to the grid are represented by $f_{import,bus,t}$ and $f_{export,bus,t}$, respectively. Binary variable $z_{connect,hub,t}$ is introduced to ensure that power can either be exported from or imported to the hub at any given time, as in (4-9)and (4-10). Constraints (4-11) and (4-12) define the limits on power flow between the hub and the bus, which are constrained by the connection asset investment, represented by the variable $\bar{f}_{connect,hub}$. Similarly, a binary variable $z_{REZ,t}$ is introduced to ensure that power flow between each REZ and its connected grid network can only flow in one direction at any given time, as described in (4-13)and (4-14) The existing REZ network transmission limit and the network expansion investment are denoted by f_{REZ}^{limit} and $\bar{f}_{REZ}$, respectively. The power flow into and out of the REZ from and to the existing grid is limited by constraints (4-15)-(4-17) The investment decision variables for candidate electrolyser, BESS, wind, solar, and H_2 gas turbine units within a hub and at a bus are represented by $\bar{P}_{ptg,hub}$, $\bar{P}_{ptg,bus}$, $\bar{P}_{BESS,hub}$, $\bar{P}_{BESS,bus}$, $\bar{P}_{wind,hub}$, $\bar{P}_{wind,bus}$, $\bar{P}_{solar,hub}$, $\bar{P}_{solar,bus}$, $\bar{P}_{HPG,hub}$, and $\bar{P}_{HPG,bus}$, respectively and constrain the maximum power input or output of the respective component as described in (4-18)and (4-19).

The model identifies the least-cost strategy, optimising both hybrid energy hub and independent investment options, and operational costs. As a result, the optimal solution may involve a combination of components being placed in the hybrid hub while others may remain as separate investments at the bus level as shown in Figure 2-2. This configuration effectively minimises the total component investment cost, where C_i^{build} and $C_i^{connect}$ represent the build cost and connection cost of each component i, and $C_{hub}^{connect}$ and C_{REZ}^{expand} denote the connection cost of the hub and the REZ transmission network expansion cost, respectively.

4.2 Methodology for integrated planning of electricity-hydrogen hybrid energy hubs and transmission

The integrated planning of electricity-hydrogen hybrid energy hubs and transmission, which involves both electricity lines and H_2 pipelines, optimises the generation, connection and transportation of energy from renewable-rich zones to demand areas.

In this work, three types of energy hubs are defined based on their components and functionality as shown in Figure 4-3, and their interconnection is described in Figure 4-4. Renewable hubs consist of renewable energy generation sources and BESS, serving as collection points for renewable electricity, which is then transmitted via electricity lines to demand sites. H_2 hubs comprise H_2-related infrastructure, including electrolysers for H_2 production, H_2 storage, and H_2 gas turbines for electricity generation, typically located near H_2 demand sites. Renewables-H_2 energy hubs integrate both renewable energy generation and hydrogen-related infrastructure, and the generated energy from hybrid energy hubs can be transported either as electricity via electricity lines or as H_2 via pipelines.

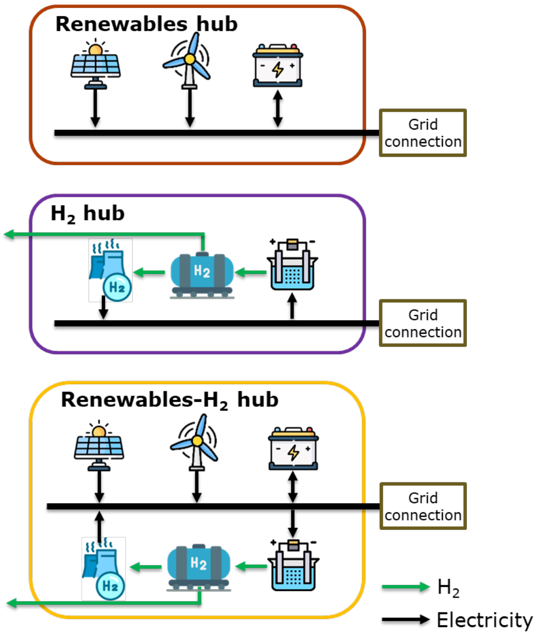


Figure 4-3: Renewables hub (top), H_2 hub (middle), and Renewables-H_2 energy hub (bottom).

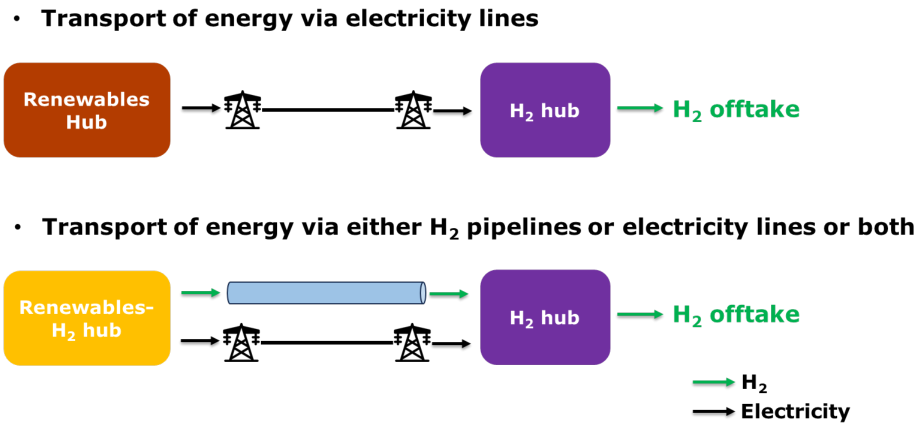


Figure 4-4: Interconnection of energy hubs.

The illustrative examples of integrated planning of energy hubs and transmission in Figure 4-5 shows that when considering only electricity transmission investment options, the hubs located in remote REZs will function as renewables hubs. In this case, H_2 production will be placed at the demand side either within an H_2 hub or a renewables-H_2 hub. These hubs will be interconnected through electricity transmission lines.

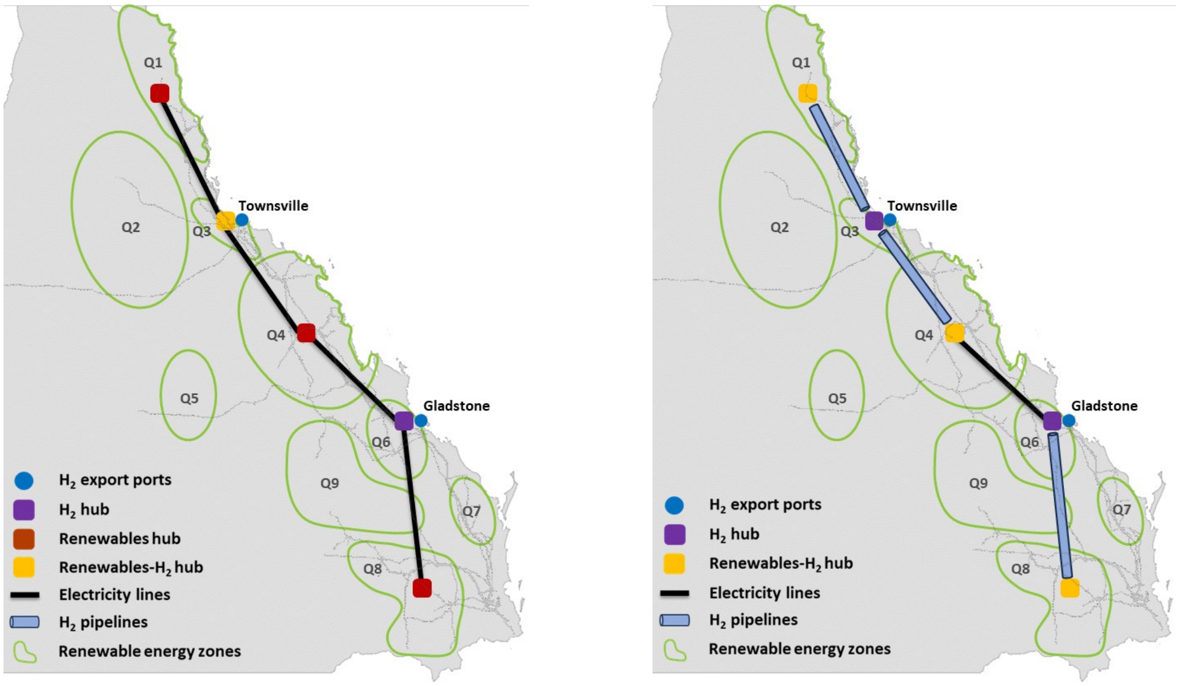


Figure 4-5: Illustrative examples of integrated planning of energy hubs and transmission when only considering electricity transmission (left) or both electricity and H_2 transmission (right).

However, when H_2 pipelines are incorporated into the planning, H_2 production sites may not necessarily be placed at demand sites. Instead, they can potentially be located within the hybrid energy hubs in the REZs, with the pipelines transporting H_2 from these hubs to demand-side locations. Additionally, the hybrid energy hubs can also be interconnected with H_2 hubs at demand sites if there is no need to transport H_2 from the REZs to the demand sites. By integrating both electricity and H_2 transmission, the system can achieve a more flexible and efficient transport of energy, optimising both the flow of electricity and H_2 to meet the electricity and H_2 demands.

A detailed formulation of the developed integrated planning model for electricity and H_2 transmission infrastructure can be found in [65], [66]. In general, a network flow model is used for electricity transmission, with constraints on the limits of branch active power flow.

A set of quasi-dynamic gas flow constraints are used to model gas volumetric flow rate, gas pressure, and *linepack*[12] in pipelines. The H_2 transmission system model is described below.

The decision of choosing a H_2 pipeline over a transmission corridor $mn \in P$ is represented by a binary variable z_{mn}^{p}. The gas pressures of the pipeline at junctions m and n are denoted by $p_{m,t}$ and $p_{n,t}$, respectively. The discretised equation of motion (4-21) describes the relationship between the average gas volumetric flow rate $\phi_{mn,t}$ of a pipeline and the gas pressures, where $\Psi_{mn} = \frac{\eta_{mn}\pi^2(D_{mn})^2}{16 l_{mn} Z_{mn} \rho^2 RT f_{mn}}$, η_{mn} is the pipeline efficiency, ρ is the gas density at standard conditions, T is the gas temperature, and R is the specific gas constant. D_{mn} and l_{mn} are the diameter and length of the pipeline. Compressibility factor Z_{mn} is computed as in [67] and the *Weymouth* friction factor is defined as $f_{mn} = 4(20.621(D_{mn})^{1/6})^{-2}$. Constraint (4-22) defines $\phi_{mn,t}$ as a function of the inlet and outlet volumetric gas flow $\phi_{mn,t}^{in}$ and $\phi_{mn,t}^{out}$. The maximum flow rate across the pipeline is denoted as $\overline{\phi}_{mn,t}$. Constraints (4-24) and (4-25) define the relationship between the junction pressure in the gas network ($p_{m,t}^{H}, p_{n,t}^{H}$) and the pipeline gas pressure at the junction. The maximum pressures $\overline{p}_m^H$ and $\overline{p}_n^H$ at junction m and n limit the pipeline gas pressure, as in (4-26) and (4-27). Constraint (4-28) defines the average pressure across the pipeline $p_{mn,t}$. The linepack $L_{mn,t}$ in the pipeline is captured by constraints (4-29) and (4-30), with (4-30) representing the discretised continuity equation and $\Phi_{mn} = \frac{\pi^2(D_{mn})^2 l_{mn}}{4\rho Z_{mn} RT}$. $\phi_{m,t}^{pth}$ denotes the output H_2 volumetric flow rate from the electrolyser at junction m and $\phi_{m,t}^{d}$ represents the H_2 demand at junction m. Constraint (4-31) ensures H_2 balance at each junction in the gas network.

$$\phi_{mn,t}\left|\phi_{mn,t}\right| = \Psi_{mn}((p_{m,t})^2 - (p_{n,t})^2) \tag{4-21}$$

$$\phi_{mn,t} = \frac{1}{2}(\phi_{mn,t}^{in} + \phi_{mn,t}^{out}) \tag{4-22}$$

$$0 \le \phi_{mn,t}, \phi_{mn,t}^{in}, \phi_{mn,t}^{out} \le \overline{\phi}_{mn,t} \tag{4-23}$$

$$(1 - z_{mn}^{p})\underline{p}_m^H \le p_{m,t} - p_{m,t}^{H} \le (1 - z_{mn}^{p})\overline{p}_m^H \tag{4-24}$$

$$(1 - z_{mn}^{p})\underline{p}_n^H \le p_{n,t} - p_{n,t}^{H} \le (1 - z_{mn}^{p})\overline{p}_n^H \tag{4-25}$$

[12] The linepack is the amount of pressured gas stored in a pipeline

$$z^{p}_{mn}\underline{p}^{H}_{m} \le p_{m,t} \le z^{p}_{mn}\overline{p}^{H}_{m} \tag{4-26}$$

$$z^{p}_{mn}\underline{p}^{H}_{n} \le p_{n,t} \le z^{p}_{mn}\overline{p}^{H}_{n} \tag{4-27}$$

$$p_{mn,t} = \frac{2}{3}(p_{m,t} + p_{n,t} - \frac{p_{m,t}p_{n,t}}{p_{m,t} + p_{n,t}}) \tag{4-28}$$

$$L_{mn,t} = \Phi_{mn} p_{mn,t} \tag{4-29}$$

$$L_{mn,t+1} = L_{mn,t} + (\phi^{in}_{mn,t} - \phi^{out}_{mn,t})\Delta t \tag{4-30}$$

$$\phi^{pth}_{m,t} = (\sum_{mn \in P} \phi^{in}_{mn,t} - \sum_{mn \in P} \phi^{out}_{mn,t}) + \phi^{d}_{m,t} \tag{4-31}$$

The developed planning framework can be generalised for any hub design, whether as renewable, hydrogen, or hybrid hubs, and provides the capability to choose between independent bus-level or hub-level investments, along with the integration of both electricity and H_2 transmission. This adaptability can provide valuable insights into the future expansion of Australia's energy system.

4.3 Case study description

This section outlines the electricity and H_2 network model, input data, and key assumptions used in the case studies. The developed integrated hybrid hubs and transmission planning model is demonstrated on case studies involving the NEM network and the envisaged REZs under the *Step Change* and the *Green Energy Exports* scenarios of AEMO's 2024 ISP. The representative year 2035 is considered for all case studies. As shown in Table 4-1, under the Normal Operation case study, four representative weeks, each from a different season, are selected to capture the seasonal variability of renewable energy. On the other hand, in addition to the four seasonal weeks used in the Normal Operation case, the Resilience case study includes one additional representative week that captures a VRE drought event. The design of the resilience case studies is described in more detail in Section 4.5.1. The modelling employs a half-hourly temporal resolution and uses the electricity and H_2 demand data from the 2024 ISP [63].

Table 4-1: Summary of Normal operation and Resilience case studies.

Case study	Representative weeks	Purpose
Normal operation	4 seasonal weeks	Capture seasonal variability of renewable energy generation
Resilience	4 seasonal weeks and 1 VRE drought week	Assess system performance during VRE drought events

4.3.1 Power system characterisation and input data

As identified in 2024 ISP [63], H_2 export in the studied year 2035 is through potential export ports in Queensland, South Australia, and Tasmania. In this work, H_2 is assumed to be exported from these three states, and their HV electricity transmission networks are modelled to include both the H_2 export ports and most of the REZs within their regions. Based on the studies in [68], and as shown in Figure 4-6, the modelled electricity transmission network in Queensland includes the 275 kV and above voltage system, consisting of 18 transmission links. In South Australia, the model represents the 275 kV network with 13 transmission links [53]. Similarly, in Tasmania, the model includes the 220 kV network, comprising 11 transmission links [69]. The transfer limits of the transmission links within the three states are sourced from AEMO[13]. To maintain computational tractability, other sub-regions of the NEM are represented by their individual reference node as in the 2024 ISP. Interconnectors link Queensland, South Australia, and Tasmania to the other sub-regions. Additionally, these other sub-regions are also connected with each other via interconnectors. The transfer limits of these interconnectors are sourced from [63].

In Queensland, South Australia, and Tasmania, each generation and storage unit is dispatched individually and connected to its adjacent electricity bus based on its geographical location. For REZs that are traversed by the modelled network, the installed component units (e.g., solar, wind, BESS, and electrolyser) can be connected to any of the electricity bus(es) within the zone. For REZs that are not located along the modelled transmission network, the installed component units are assumed to connect to the adjacent modelled electricity bus.

On the other hand, in each of the other sub-regions, all generation and storage units are assumed to be connected to their respective reference nodes. Since the detailed electricity

[13] Transmission Equipment Ratings. https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings

transmission network is not modelled in New South Wales and Victoria, the installed component units within REZs in these two states are assumed to connect to the reference node of the respective sub-region in which the REZ is located.

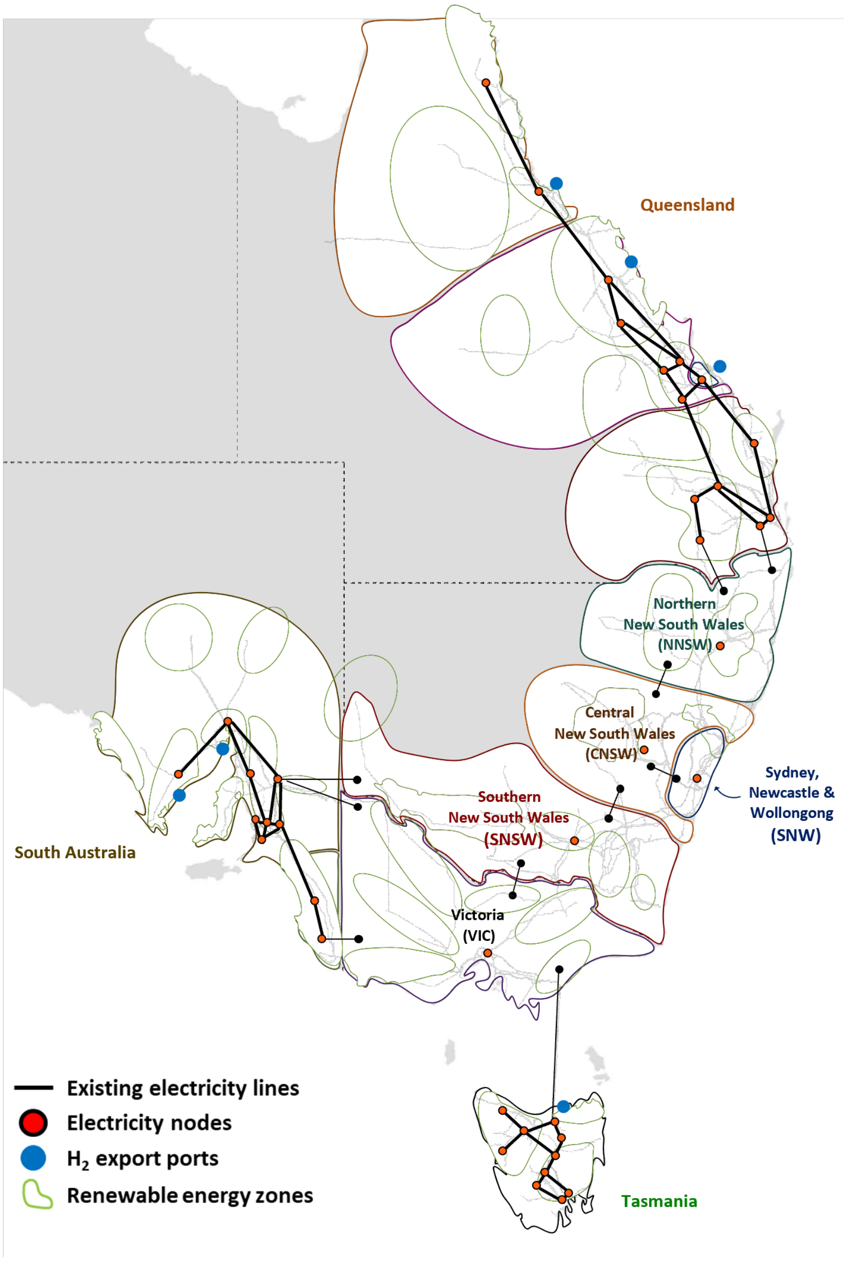


Figure 4-6: Modelled electricity transmission network for the NEM.

Table 4-2 and Table 4-3 present the existing capacity of VRE units in 2024 and the projected capacity of thermal, storage, and dam hydro units in 2035 for the case studies. Storage systems are classified into three categories based on duration type: shallow (less than 4 hours), medium (4 to 12 hours), and deep (more than 12 hours). These figures are obtained from the NEM Generation Information Database and the 2024 ISP's Optimal Development

Path (ODP) which includes a set of actionable and future projects that maximises consumer benefits under the *Step Change* and the *Green Energy Exports* scenarios, while accounting for future uncertainties.

Table 4-2: Installed capacities under the Step Change scenario.

Technologies [GW]	Queensland	New South Wales	Victoria	South Australia	Tasmania
Coal	0.0	1.4	0.0	0.0	0.0
Gas	5.2	4.7	2.2	2.1	0.2
Wind	2.5	2.8	4.5	2.6	0.6
Utility solar	3.1	4.7	1.2	0.6	0.0
Dam hydro	0.2	2.3	2.2	0.0	2.6
Deep storage	2.1	2.9	0.0	0.0	0.1
Medium storage	0.8	3.6	0.4	0.0	0.0
Shallow storage	2.1	4.7	3.8	0.9	0.0

Table 4-3: Installed capacities under the Green Energy Exports scenario.

Technologies [GW]	Queensland	New South Wales	Victoria	South Australia	Tasmania
Coal	0.0	0.0	0.0	0.0	0.0
Gas	4.2	4.2	2.8	1.6	0.2
Wind	2.5	2.8	4.5	2.6	0.6
Utility solar	3.1	4.7	1.2	0.6	0.0
Dam hydro	0.2	2.3	2.2	0.0	2.6
Deep storage	2.2	3.4	0.2	0.0	0.2
Medium storage	6.3	4.3	2.6	0.4	0.0
Shallow storage	2.1	2.1	2.7	0.9	0.0

4.3.2 Hydrogen system characterisation and input data

As shown in Figure 4-7, to develop a candidate H_2 network that enables transporting H_2 to export ports and domestic H_2 demand sites, multiple H_2 junctions and pipeline corridors are introduced across the three states, based on the proposed provisional corridors in [70], with modifications tailored to the needs of this study. Specifically, Queensland comprises 7 H_2 junctions and 5 H_2 pipeline corridors, South Australia includes 6 H_2 junctions and 5 H_2 pipeline corridors, and Tasmania incorporates 4 H_2 junctions and 2 H_2 pipeline corridors. Each of the rest sub-regions is also modelled as a respective H_2 node to only account for domestic H_2 demand.

The domestic H_2 consumption and H_2 export targets for each state in 2035 under the Step *Change* and *Green Energy Exports* scenarios are outlined in Table 4-4 and Table 4-5, and the model determines the amount of H_2 to be exported through each port in the respective state. Domestic H_2 demand within Queensland, South Australia, and Tasmania is distributed across all H_2 nodes, with allocation based on the ratio of total electricity demand at nodes linked to each H_2 node relative to total state-wide electricity demand. In the other sub-regions, domestic H_2 demand is directly allocated to the respective H_2 node. Both export and domestic H_2 demands are assumed to be met on a daily basis with a fixed daily target.

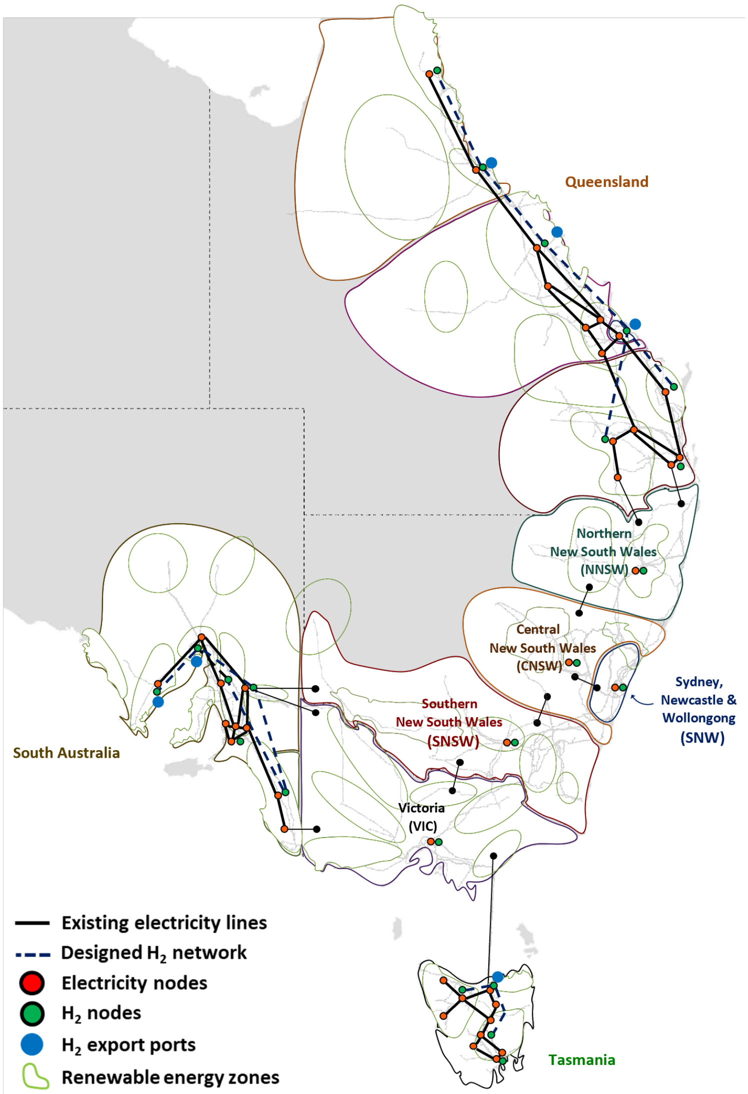


Figure 4-7: Modelled electricity-hydrogen network for the NEM

Table 4-4: Hydrogen demand in 2035 under the Step Change scenario.

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Domestic H_2 (Mt)	0.17	0.10	0.13	0.03	0.03
Export H_2 (Mt)	0.05	0	0	0.03	0.04

Table 4-5: Hydrogen demand in 2035 under the Green Energy Exports scenario.

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Domestic H_2 (Mt)	0.24	0.26	0.28	0.05	0.01
Export H_2 (Mt)	0.66	0	0	0.39	0.50

4.3.3 Candidate investment options

Figure 4-8 depicts the candidate transmission investment corridors and interconnector investment options for the case studies. To ensure a fair comparison, the same pipeline corridors are used for both candidate electricity transmission and H_2 pipeline options in Queensland, South Australia, and Tasmania, as indicated by the pink dashed lines. Each corridor considers a 2GW HVAC transmission line option and an H_2 pipeline option with a capacity that is determined by multiplying the electricity line capacity by the electrolyser efficiency. This ensures that the H_2 pipeline capacity reflects the H_2 energy that can be delivered after accounting for electrolyser conversion losses, whereas the electrolyser efficiency is considered for the electricity line after it transports electrical energy to the production site. In total, there are 12 electricity transmission and 12 H_2 pipeline investment options in the three states.

REZ transmission expansion investment options are implemented for REZs not directly located along the modelled transmission network, including some REZs in Queensland and South Australia, as well as all REZs in New South Wales and Victoria. These investment options are represented by the cost of increasing REZ transmission network limit for connecting more VRE from remote REZs to the existing grid. The investment costs are modelled as linear functions of expansion capacity. The existing REZ transmission network limits for each REZ are obtained from [63].

Additionally, 9 interconnector investment options are considered for the entire NEM, as depicted by the purple dashed lines in Figure 4-8. These interconnectors are identified as the actionable projects in 2024 ISP [63].

All electricity transmission, REZ transmission expansion and pipeline options assume a lifetime of 40 years and a lead time of 5 years. The costs for REZ transmission network expansion for each REZ are sourced from [63] and the range of investment costs is outlined in Table 4-6. The Costs and technical parameters for electricity transmission and are sourced from [63], and for H_2 pipelines are obtained from [71], with details provided in Appendix D.

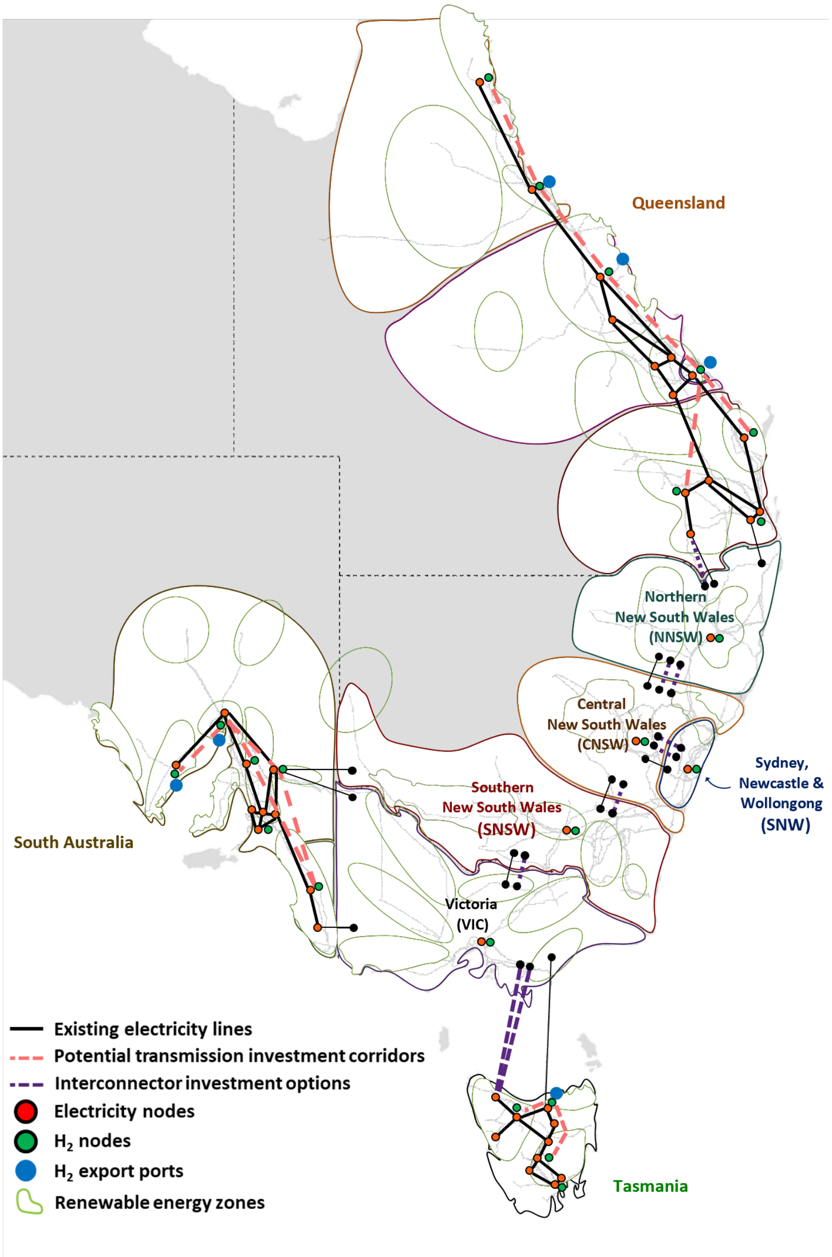


Figure 4-8: Illustration of candidate transmission investment corridors and options.

Table 4-6: REZ transmission expansion costs.

	Step Chane Scenario	Green Energy Exports Scenario
REZ transmission expansion cost (M$/MW)	0.12-2.82	0.05-1.85

VRE and BESS candidate investment options are considered in all REZs across the NEM. However, since H_2 pipelines are not modelled for connecting some REZs that are not located along the modelled transmission network, H_2 production is excluded from those REZs. Accordingly, H_2-related investment options, including electrolysers, H_2 storage, and H_2 gas turbines, are only considered at the H_2 junctions that are coupled with a modelled bus or with reference node. As a result, all independent components and renewables-H_2 hub investment options are considered at modelled buses that are coupled with H_2 junctions within REZs in Queensland, South Australia, and Tasmania. Additionally, independent VRE and BESS, and renewables hub investment options are considered at selected modelled buses within REZs in these three states that are not coupled with H_2 junctions. For the remaining REZs across the NEM, which are not located along the modelled transmission network, independent VRE and BESS, and renewables hub investment options are considered in these regions. H_2 hub investment options are considered at the reference nodes in New South Wales and Victoria.

The costs and technical parameters for candidate 8-hour BESS, PV, wind, proton exchange membrane (PEM) electrolysers, H_2 storage tanks, and H_2 turbines are sourced from [64], [72] and outlined in The definitions of build cost, connection cost, and hybrid energy hub are summarised in Table 4-9.

Table 4-7. The renewable traces for the renewable investments in REZs are obtained from [63]. A penalty factor of M$0.29/MW is applied to VRE capacity installations that exceed the renewable resource limit in a REZ but remain within the land use limit [63]. The connection costs for VRE options vary across different REZs, while the connection costs for BESS, electrolysers, and H_2 gas turbines depend on the regions in which they are installed. The range of connection costs for each technology under both *Step Change* and *Green Energy Exports* Scenario are sourced from [63] and outlined in Table 4-8. The efficiency of large MV/HV power transformer is considered as 99% [73]. The annual fixed operating cost is assumed to be 2% of the total project investment cost. The definitions of build cost, connection cost, and hybrid energy hub are summarised in Table 4-9.

Table 4-7: Cost and parameter assumptions for candidate component options.

Technologies	**Build cost ($/kW)**		**Efficiency (%)**	**Life time (yr)**
	Step Chane Scenario	**Green Energy Exports Scenario**		
8-hour BESS	1,762.2	1,240.3	91.1	20
Utility-scale solar	996.8	987.0	97.1	30
Wind	1,948.9	1,932.2	97.0	30
PEM electrolyser	777.4	577.4	82.8	25
H_2 storage tank	468.6	468.6	99.5	30
H_2 gas turbine	2,298.6	2,298.6	34.0	40

Table 4-8: Connection costs for candidate component options.

Technologies	Connection cost ($/kW)
8-hour BESS	77.5-106.9
Utility-scale solar	109.8-307.1
Wind	109.8-307.1
PEM electrolyser	77.5-106.9
H_2 gas turbine	85.5-115.5

Table 4-9: Definition of key terms.

Terms	Definition
Build cost	Equipment cost for main components (e.g., PV modules, wind turbines, cables, power converters) and installation cost
Connection cost	Equipment cost for HV substation (e.g., MV/HV transformers, switchyard, reactive plant, feeder) and installation cost
Hybrid energy hub	(i) Renewables hub: Comprises renewable energy generation and BESS storage technologies (ii) H_2 hub: Includes H_2-related technologies (e.g., electrolysers, H_2 storage, H_2 gas turbines) (iii) Renewables-H_2 hub: Combines renewable energy generation, storage, and H_2-related technologies

4.4 Integrated electricity-hydrogen system planning — NEM case studies

In this section, the case studies for the entire NEM seek to identify the cost-effective investment strategies for meeting electricity and H_2 demand while assessing how the integration of H_2 pipelines and hybrid energy hubs influences investment portfolios and system costs, respectively.

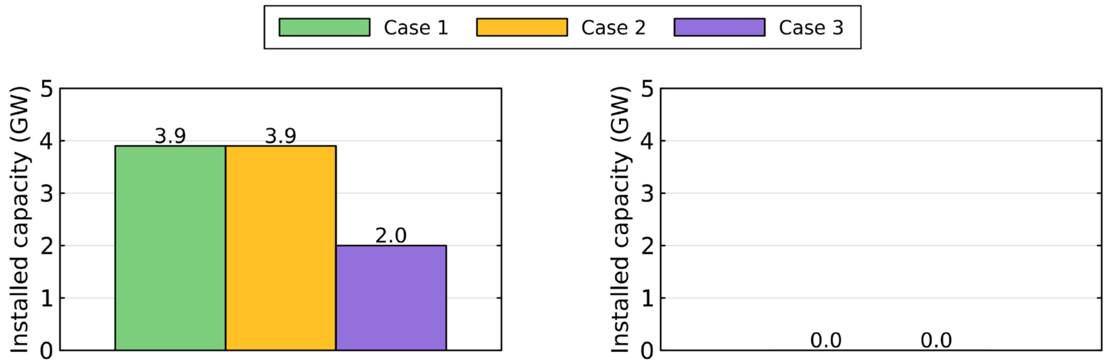
As presented in Table 4-10, three case studies under both the *Step Change* and the *Green Energy Exports* scenarios are considered to compare different infrastructure investment approaches. Case 1-Base includes only electricity lines and bus-level independent component investment options. Case 2-WithPipe additionally includes H_2 pipelines investment options to assess their impacts on integrated electricity-hydrogen system planning. Case 3-Hubs further incorporates hybrid energy hub (which could have *shared* connection assets) investment options to assess their additional benefits.

Table 4-10: Investment assumptions for each case study under the Step Change and Green Energy Exports scenarios.

Investment options	Case 1-Base	Case 2-WithPipe	Case 3-Hubs
Electricity lines	✓	✓	✓
H_2 pipelines		✓	✓
Bus-level independent components	✓	✓	✓
Hybrid energy hubs			✓

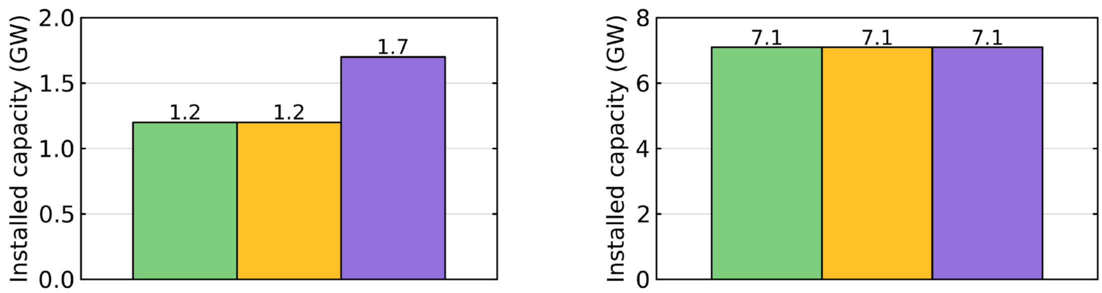
A deterministic planning model with a half-hourly resolution is employed to conduct the case studies, focusing on the year 2035 under the *Step Change* and the *Green Energy Exports* scenarios in AEMO's 2024 ISP. Given that investments in transmission infrastructure (i.e., electricity lines, REZ network expansion, and H_2 pipelines) have a lead time of 5 years, it is assumed that the corresponding payments for these infrastructure investments begin in 2030 if the model decides to operate them from 2035.

The results analysis section is structured in two parts. The first evaluate the potential benefits of incorporating H_2 pipeline and the second evaluates the benefits of hybrid energy hubs, respectively. Figure 4-9 and Figure 4-10 present the overall investment results for each case under the *Step Change* and the *Green Energy Exports* scenarios, respectively. The NPV of the annuitised costs in 2035 for each case under the *Step Change* and the *Green Energy Exports* scenarios are shown in Table 4-11 and Table 4-12, respectively. More details on investments in each REZ can be found in Appendix E.



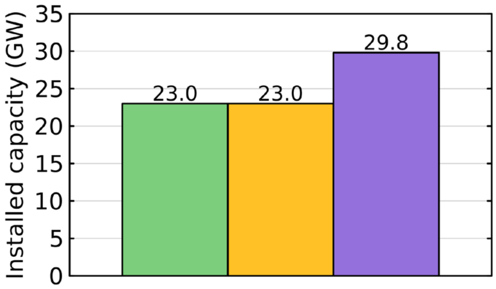
(a) Electricity lines

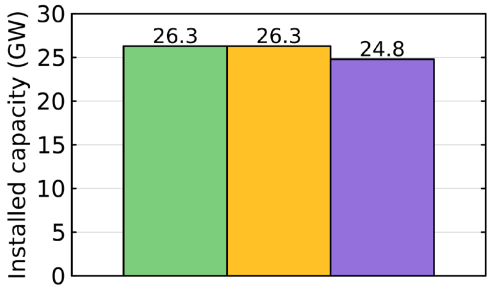
(b) H_2 pipelines



(c) REZ network expansion

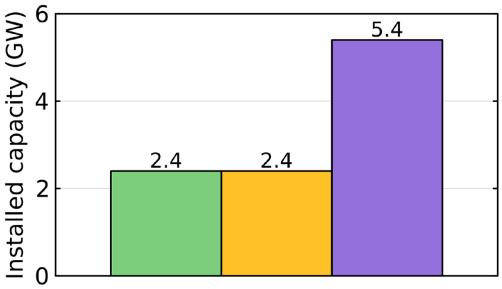
(d) Electrolysers

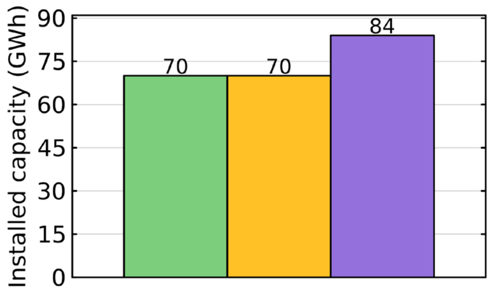




(e) Solar

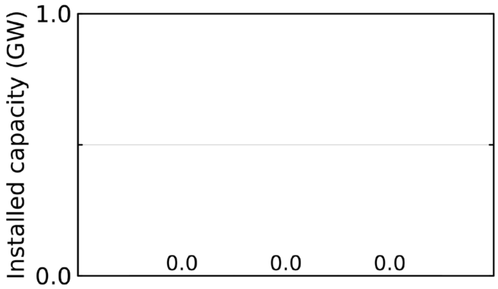
(f) Wind

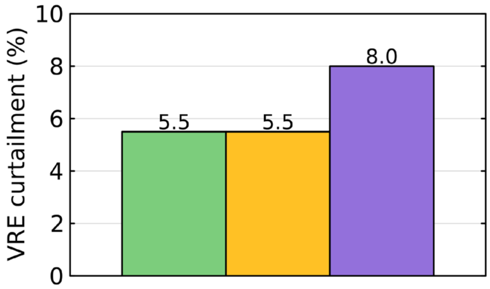




(g) BESS

(h) H_2 storage tanks

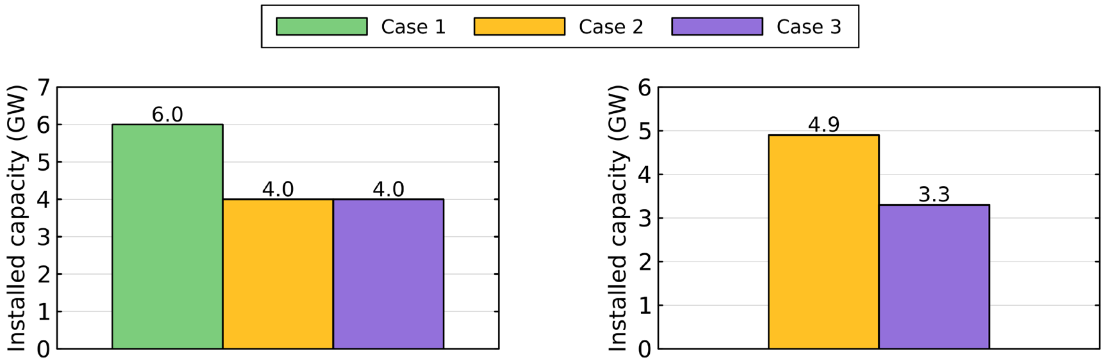




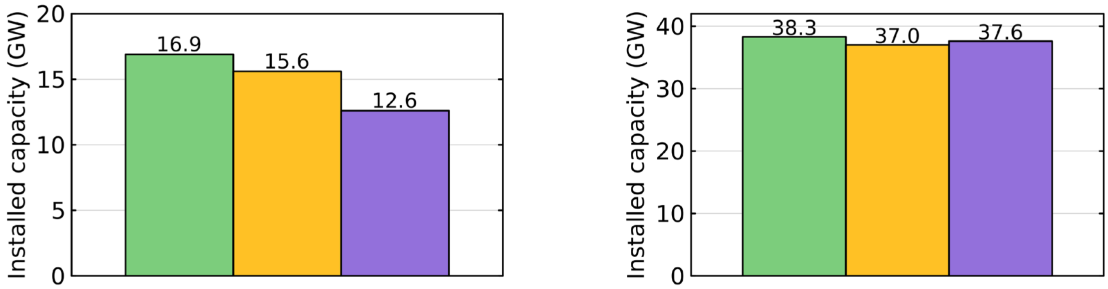
(i) H_2 turbines

(j) VRE curtailment

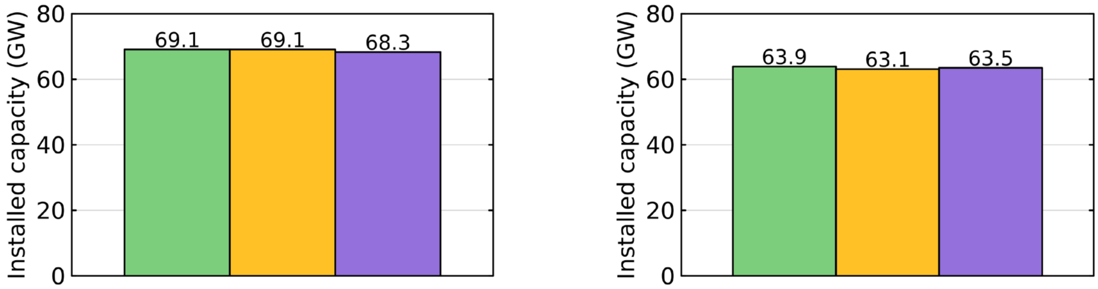
Figure 4-9: Optimal investment results (a)-(i) and VRE curtailment (j) for each case under the Step Change scenario under the Normal operation case study.



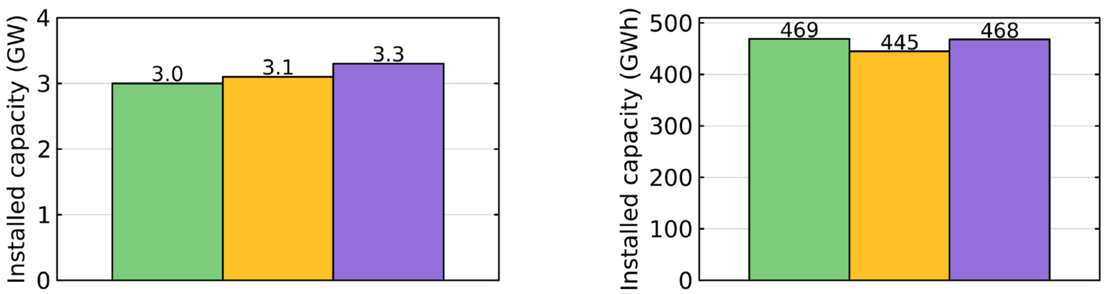
(a) Electricity lines *(b) H_2 pipelines*



(c) REZ network expansion *(d) Electrolysers*

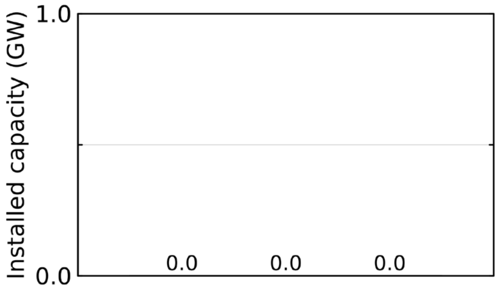


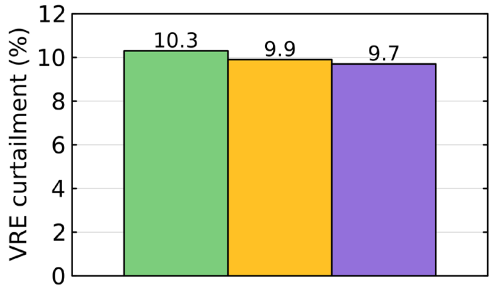
(e) Solar *(f) Wind*



(g) BESS

(h) H_2 storage tanks





(i) H_2 turbines

(j) VRE curtailment

Figure 4-10: Optimal investment results (a)-(i) and VRE curtailment (j) for each case under the Green Energy Exports scenario under the Normal operation case study.

Table 4-11: Net present value of total costs in 2035 for each case under the Step Change scenario under the Normal operation case study.

	Operating cost (M$)	**Annuitised investment cost (M$)**	**Total cost (M$)**
Case 1-Base	2,251	4,164	6,415
Case 2-WithPipe	2,251	4,164	6,415
Case 3-Hubs	2,035	4,249	6,284

Table 4-12: Net present value of total costs in 2035 for each case under the Green Energy Exports scenario under the Normal operation case study.

	Operating cost (M$)	**Annuitised investment cost (M$)**	**Total cost (M$)**
Case 1-Base	2,287	11,033	13,320
Case 2-WithPipe	2,209	10,904	13,113
Case 3-Hubs	2,184	10,217	12,401

4.4.1 Merits of H_2 pipelines

Step Change scenario

As shown in Figure 4-9 and Table 4-11, investment results are identical in Case1-Base and Case2-withPipe under the *Step Change* scenario as H_2 pipelines are not selected by the model in any of the 3 cases. This is because both domestic and export H_2 demands can be met through local electrolysis production, supported by existing and newly built electricity transmission infrastructure. As a result, there is no need for dedicated H_2 transmission. This indicates that under a scenario with relatively low H_2 demand, leveraging the electricity network for H_2 production is sufficient and avoids unnecessary investment in dedicated H_2 pipeline infrastructure.

<u>Green Energy Exports scenario</u>

On the other hand, the merits H_2 pipelines become evident when system includes large-scale H_2 demand under the Green *Energy Exports* Scenario. As shown in Figure 4-10(a)-(b) and illustrated in Figure 4-11, compared to Case 1-Base, the 2 GW HVAC line investment between REZs T1 and T2 in Tasmania is displaced by a *cheaper* H_2 pipeline in Case 2-WithPipe. This is because achieving the same increase in transmission capacity through electricity lines is more costly than through an increase in pipeline diameter [70]. The other two installed H_2 pipelines in Case 2-WithPipe are in parallel with the HVAC line investments connecting REZs Q1 to Q3, and T3 to T1, complementing electricity line investments.

Additionally, Figure 4-10(c) shows a 1.3 GW reduction in REZ network expansion in Case 2-WithPipe compared to Case 1-Base, primarily because more VRE from REZ Q1 can be transported to REZ Q3 via electricity lines or the installed H_2 pipeline, thereby reducing the need for additional VRE generation from REZ Q2 as detailed in Table a-11. Furthermore, in Case 2-WithPipe, more VRE generated from REZ Q1 is utilised to produce H_2 for export through the port located in REZ Q3, reducing the amount of energy transmitted southward to meet local electricity demand. As a result, compared to Case 1-Base, Case 2-WithPipe sees an increase of 0.1 GW in BESS installation in central and southern Queensland to maintain supply reliability, as shown in Figure 4-10(g) and detailed in Table a-11.

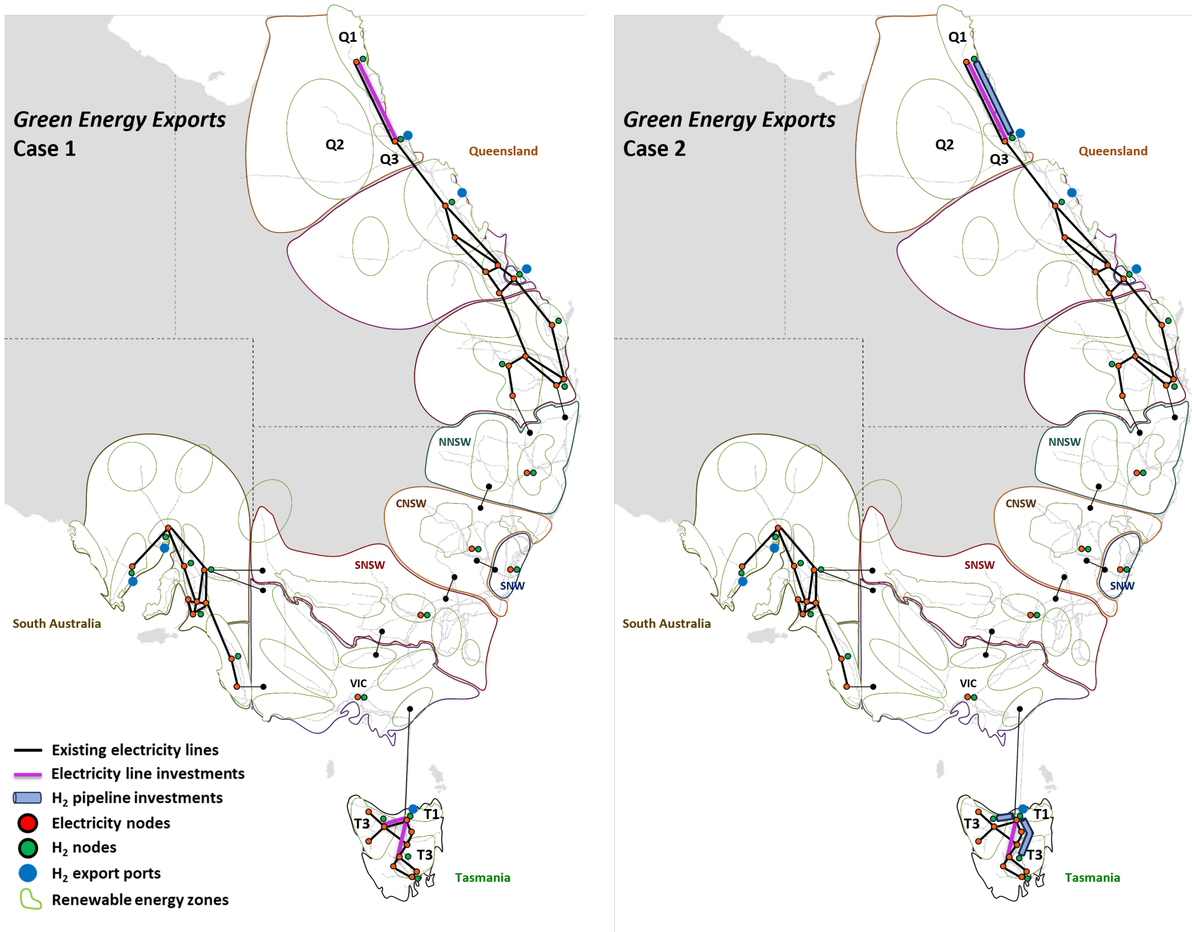


Figure 4-11: Transmission investment results in Case 1-Base and Case 2-WithPipe under the Green Energy Exports scenario under the Normal operation case study.

Moreover, the model optimises the co-location of H_2 pipelines and electrolysers in both export locations and remote REZs. By enabling H_2 to be transported from regions with better VRE availability, H_2 pipelines in Case 2-WithPipe reduce the need for additional electrolysers at export locations, thereby avoiding the installation of additional costly wind generation at export locations compared to Case1, as detailed in Table a-11. As a results, Figure 4-10(d)-(f) show that Case 2-WithPipe sees a reduction of 1.3 GW in electrolyser capacity and 0.8 GW in wind capacity in Case 2-WithPipe compared to Case 1-Base. Besides, unlike electricity transmission lines, pipelines can provide inherent energy storage, which reduces installed capacity of 24 GWh in stationary H_2 storage in Case 2-WithPipe compared to Case 1-Base (Figure 4-10(h)).

Figure 4-12 further illustrates that the three selected H_2 pipelines in Case 2-WithPipe can accommodate up to 10 GWh of storage across the four representative weeks in 2035. This displacement of stationary H_2 storage (in H_2 storage tanks) by linepack storage in H_2 pipelines highlights the role of H_2 pipelines in both transport and storage, offering a cost-effective alternative to standalone H_2 storage assets like H_2 storage tanks. Consequently, VRE is more effectively utilised in Case 2-WithPipe, showing a 0.4% reduction in VRE curtailment compared to Case 1-Base, as presented in Figure 4-10(j). H_2 turbines are not chosen by the model in both cases as installing them results in a very low round-trip efficiency, which increases operational costs.

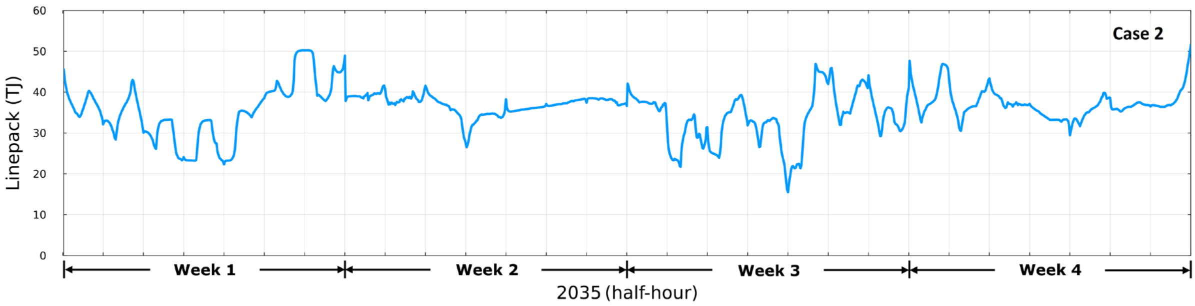


Figure 4-12: Profile of total linepack in the three installed pipelines in Case 2-WithPipe over the selected four representative weeks in 2035 under the Green Energy Exports scenario under the Normal operation case study.

Under the cost and other input assumptions for this specific system topology and transmission corridors, the comparison between Case 1-Base and Case 2-WithPipe demonstrates that including H_2 pipelines as options in the electricity-hydrogen planning can enhance system flexibility by leveraging their transport and storage capabilities, improve VRE utilisation, and reduce overall system costs when large-scale H_2 demand is present. Compared to Case 1-Base, the higher investment costs in total electricity lines and H_2 pipelines in Case 2-WithPipe are primarily offset by reduced investments in REZ network expansion, electrolysers, wind generation, and H_2 storage, resulting in a 1.2% decrease in total investment costs as shown in Table 4-12. Besides, improved utilisation of VRE in Case 2-WithPipe leads to a 3.4% decrease in system operating costs, compared to Case 1-Base. Overall, Case 2-WithPipe achieves a 1.6% decrease in total costs, compared to Case 1-Base. It is important to note that these savings might be higher in later years, such as 2040 and beyond, as H_2 export demand is projected to grow substantially [63].

4.4.2 Merits of hybrid energy hubs with shared connection assets

The merits of hybrid energy hubs are captured when comparing Case 2-WithPipe with Case 3-Hubs. As summarised in Table 4-11 and Table 4-12, Case 3-Hubs sees a 2.0% and a 5.7% decrease in total system costs, under the *Step Change* and the *Green Energy Exports* scenarios, respectively, compared to Case 2-WithPipe. These potential savings result from the introduction of hybrid energy hubs with shared connection assets that leverage diversity of VRE, electrolysers, and storage technologies within a hub. This integrated configuration supports more efficient local energy supply and use, reducing the need for long-distance energy transport infrastructure.

Step Change scenario

As shown in Figure 4-9(a) Electricity (a) and illustrated in Figure 4-13, compared to Case 2-WithPipe, the inclusion of hybrid energy hub investment options in Case 3-Hubs displaces the 1.9 GW interconnector between South New South Wales and Victoria. With less reliance on electricity transfer from the northern to the southern NEM regions, more VRE generation and storage are developed locally in Victoria. Specifically, as shown in Figure 4-9(e)-(h), Case 3-Hubs sees additional investments of 6.8 GW solar capacity, 3 GW BESS capacity, and 11 GWh H_2 storage capacity, while avoiding 1.5 GW of costly wind generation, compared to Case 2-WithPipe. As detailed in Table a-10, most of the additional VRE and storage investments are located in Victoria. Despite this substantial increase in VRE capacity in Victoria, only 0.7 GW of additional REZ network expansion is required within the region, as also detailed in Table a-10. This is because the added VRE capacity is primarily needed to meet winter demand, when normalised VRE output in Victoria is relatively low, requiring larger installed capacity to capture sufficient VRE. In other seasons, the surplus VRE generation can stored in additional BESS investments, improving overall system flexibility and the utilisation of newly installed assets. Once again, in both cases, the optimisation model does not choose to invest in H_2 turbines as installing them results in a low round-trip efficiency that increases operational costs.

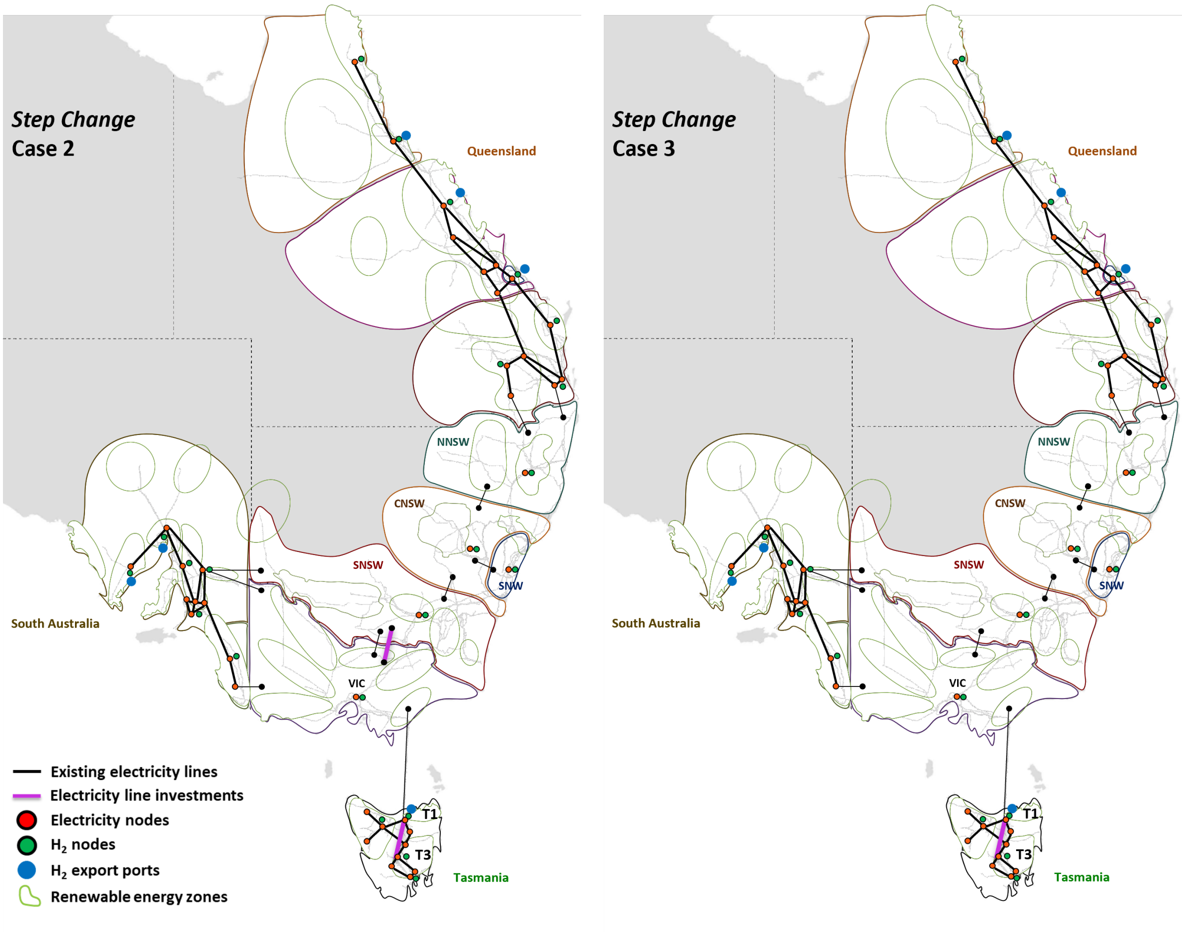


Figure 4-13: Transmission investment results in Case 2-WithPipe and Case 3-Hubs under the Step Change scenario under the Normal operation case study.

By integrating VRE generation and storage within a hub, Case 3-Hubs minimises the capacity of connection assets and associated costs. This makes it more cost-effective to export generated energy from hubs to the grid, reducing the need for additional electricity transmission investments. As shown in Table 4-13, the cost savings from coupling components behind shared connection assets, combined with improved efficiency drive energy hubs investment and dominant in REZs in Case 3-Hubs. The percentage of bus-level investment reflects two types of configurations: (i) investments that involve only a single technology and therefore do not form a hub, and (ii) mixed investments where some technologies are co-located as a hub while others remain at the bus level.

Table 4-13: Percentage of bus-level and hub-level investments in REZs in Case 3-Hubs under the Step Change scenario under the Normal operation case study.

Investments in REZs	Within energy hubs (%)	At bus-level (%)
Solar	94.3	5.7
Wind	95.4	4.6

BESS	96.1	3.9
Electrolyser	97.3	2.7

As a result, as shown in Table 4-11, although Case 3-Hubs sees a 2.0% increase in investment costs compared to Case 2-WithPipe, this cost increase is offset by reduced needs for interconnector transmission, cost savings from shared connection assets within a hub, and lower system operating costs through using more VRE with larger installed VRE capacity despite higher curtailment (Figure 4-9(j)). Overall, this leads to a 2.0% reduction in total system costs, compared to Case 2-WithPipe.

Green Energy Exports scenario

Under large-scale H_2 demand scenario, integrating VRE and electrolysers within hybrid energy hubs enables H_2 demand to be met more efficiently utilising local VRE generation for electrolysis, which reduces the need for long-distance energy transport. As shown in Figure 4-10(b)-(c) and illustrated in Figure 4-14, this leads to the displacement of the H_2 pipeline between REZs T1 and T2 in Tasmania and a 3 GW reduction in REZ network expansion in Case 3-Hubs compared to Case 2-WithPipe. As detailed in Table a-11, REZ network expansion is primarily reduced in New South Wales and Victoria, due to lower peak power flow requirements from REZs to the grid for export to other regions, as more energy is consumed locally within hubs. With less REZ network capacity, daytime energy exports from these regions to the grid are reduced in Case 3-Hubs, compared to Case 2-WithPipe.

To compensate for this reduction in energy exports, as shown in Figure 4-10(f)-(g) and detailed in Table a-11, an additional 0.4 GW of wind generation and 0.2 GW BESS are invested in New South Wales and Victoria. These investments support energy supply during off-peak hours (e.g., at night or early morning) and shift solar generation to later in the day, ensuring that fixed daily domestic H_2 targets in New South Wales and Victoria are consistently met. This also reduces the need for electrolysers in New South Wales and Victoria, resulting in 0.2 GW less electrolyser capacity as detailed in Table a-11, since VRE can be utilised more evenly throughout the day. Moreover, as shown in Figure 4-10(h) and detailed in Table a-11, additional H_2 storage is installed in Tasmania to compensate the displaced investment of the H_2 pipeline.

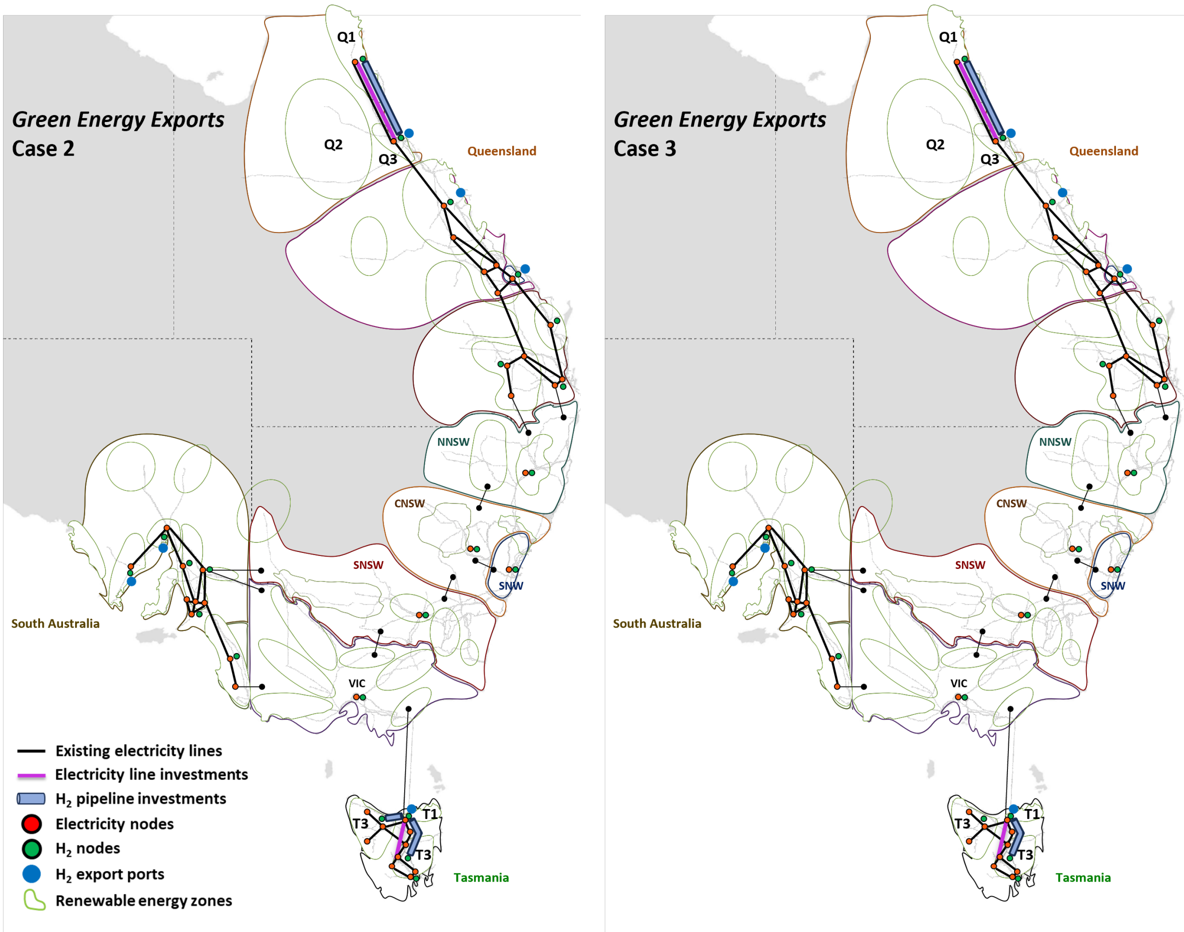


Figure 4-14:Transmission investment results in Case 2-WithPipe and Case 3-Hubs under the Green Energy Exports scenario under the Normal operation case study.

Furthermore, Figure 4-10(d)-(e) and (j) show that compared to Case 2-WithPipe, the efficient use of VRE generation for electrolysis within hybrid energy hubs in Case 3-Hubs also reduces solar capacity by 0.8 GW and increases electrolyser capacity by 0.8 GW in Queensland, South Australia and Tasmania, supporting more efficient H_2 production from the available VRE and reducing VRE curtailment by 0.2%. Meanwhile, H_2 turbines are not selected by the model in either case due to their low round-trip efficiency. By integrating components within a hub, this configuration reduces costs of connection assets across the grid, making them a dominant investment choice in REZs by the model, as presented in Table 4-14. Again, the share of bus-level investments either reflects deployments of single technologies at the bus or partial hub configurations at the bus where not all components are co-located.

Table 4-14: Percentage of bus-level and hub-level investments in REZs in Case 3-Hubs under the Green Energy Exports scenario under the Normal operation case study.

Investments in REZs	Within energy hubs (%)	At bus-level (%)
Solar	96.7	3.3
Wind	94.6	5.4
BESS	100	0
Electrolyser	99.7	0.3

As a result, as shown in Table 4-12, Case 3-Hubs witnesses a 1.1% decrease in system operating costs through improve VRE utilisation, and a 6.3% decrease in investment costs due to the reduced needs for H_2 transmission and REZ network expansion, and cost savings from shared connection assets, leading to an overall 5.7% decrease in total system costs, compared to Case 2-WithPipe.

Under the cost and other input assumptions for this specific system topology and transmission corridors, the comparison between Case 2-WithPipe and Case 3-Hubs under both scenarios demonstrates that incorporating hybrid energy hubs into the electricity-hydrogen system provides potential benefits by enabling more efficient use of local VRE for H_2 production within hubs and reducing the need for investments in transmission infrastructure. As observed in both scenarios, hybrid energy hubs impact investment decisions geographically and how they interact temporally to minimise the total system costs. However, it is important to note that since the exact locations of VRE resources within REZs are uncertain, they may not be geographically co-located. In such cases, coupling components within a energy hub may not be realistic, and the system may require additional infrastructure, reducing the potential savings.

4.5 Integrated electricity-hydrogen system planning during VRE droughts

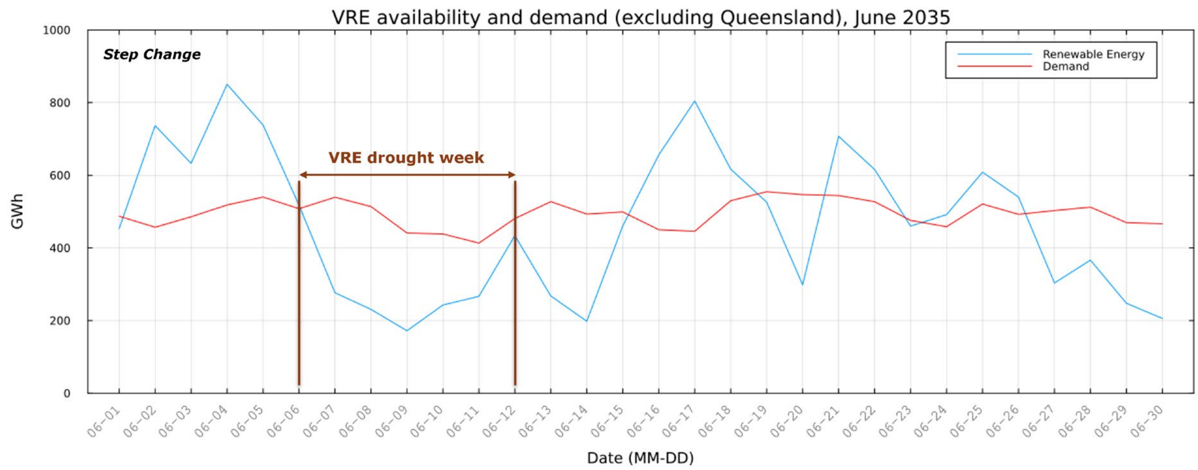
As assessed by AEMO [63], the NEM must be resilient under challenging weather conditions, including long, dark, and still periods. These conditions, which typically last for several hours or a full day, are most common during winter when solar generation is low and wind conditions are calm. In the NEM with high shares of VRE, such VRE droughts pose a risk to reliability if sufficient firming resources are not available for dispatch. Resilience in such scenarios is achieved through a diverse mix of generation technologies, firming resources, and transmission expansions that enable electricity to flow from regions with surplus to those experiencing deficits.

To represent such VRE drought events, a set of resilience case studies are designed and outlined in Section 4.5.1. the Resilience case study is compared with the Normal operation case study analysed in Section 4.4 to understand the broader impacts of VRE droughts on system planning. The analysis then focuses on the potential benefits of H_2 pipelines and hybrid energy hubs in enhancing system resilience under VRE drought conditions, with their impacts on system costs, system operation, and investment portfolios.

4.5.1 Resilience case studies design

To evaluate the impact of VRE droughts on system performance and resilience, the design of the resilience case studies is based on real-world data and forecasts from the "Appendix 4. System Operability" of 2024 ISP. Specifically, the VRE profile from a severe drought event observed in June 2019, during which the southern NEM (New South Wales, Victoria, South Australia, and Tasmania) experienced extremely high residual demand due to low VRE output, is used as a reference for modelling future VRE droughts in June 2040, as detailed in the document. To identify the representative VRE drought week in 2035, the forecast VRE profiles for June 2040 are applied to June 2035, while considering the projected VRE capacity and demand in 2035 under the *Step Change* and the *Green Energy Exports* scenarios from 2024 ISP's ODP.

As shown in Figure 4-15, a representative VRE drought week is identified under both scenarios, where VRE generation in the southern regions is severely limited, leading to extremely high residual demand. This week captures the fluctuating nature of VRE droughts, including periods of low generation and periods of VRE relief at the beginning and end, providing a more realistic representation of system challenges during such events.



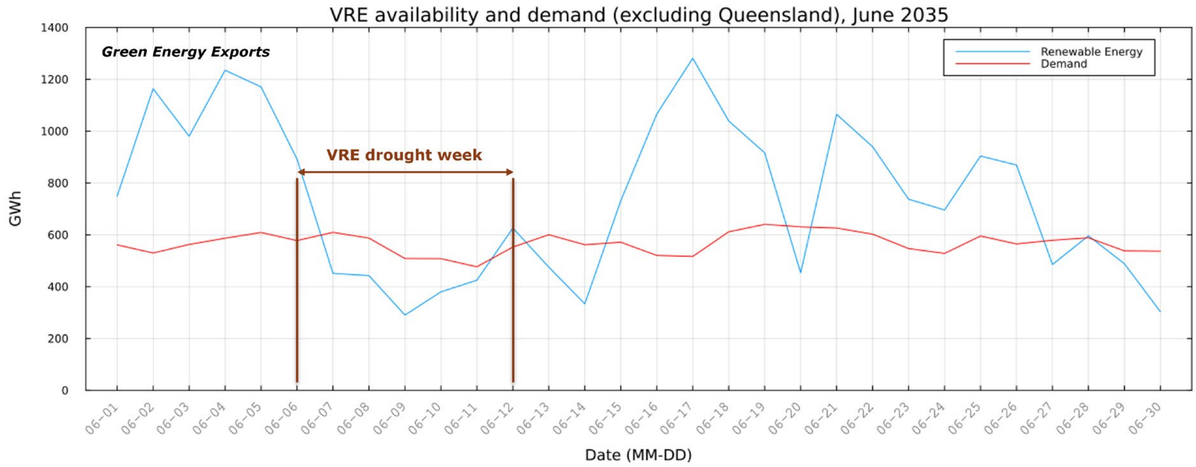


Figure 4-15: Representative VRE drought week for the Resilience case studies under the Step Change (top) and Green Energy Exports (bottom) scenarios.

In order to capture the effects of a VRE drought on system operation and investment decisions, this identified VRE drought week is incorporated into the case studies alongside the four normal operation weeks used in Normal operation case study. The VRE drought week is assigned the same demand profile as the normal winter week but with the reduced VRE availability associated with the severe VRE drought conditions. As a result, the VRE drought week is assigned a 1/52 weighting and the normal winter week is given a 3/13 (1/4 – 1/52) weighting, together reflecting the total winter period. The summer, autumn, and spring weeks each receive a 1/4 weighting. This approach enables the analysis of normal seasonal demand and VRE profile patterns while accounting for the impact of the VRE drought on the system.

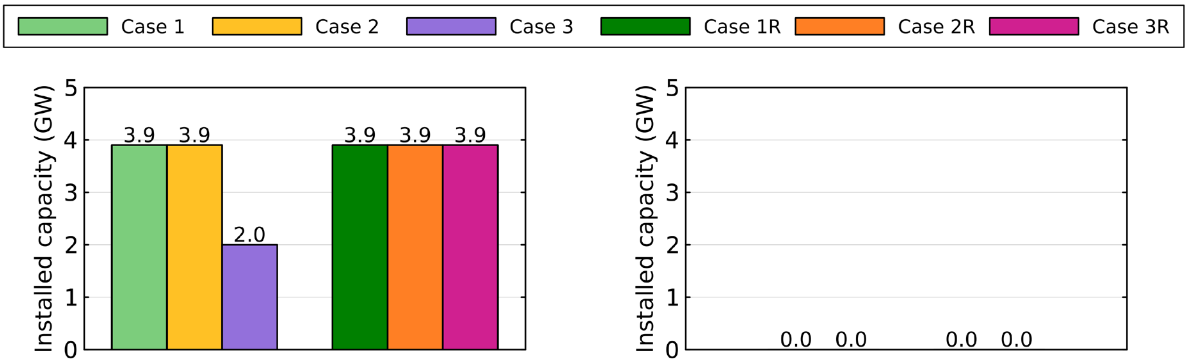
Similar to Normal operation case study, three resilience case studies with different investment options under the *Step Change* and the *Green Energy Exports* scenarios are considered, as presented in Table 4-15.Table 4-15

Table 4-15: Investment assumptions for each case study under the Step Change and the Green Energy Exports scenarios under the Resilience case study.

Investment options	Case 1R-Base	Case 2R-WithPipe	Case 3R-Hubs
Electricity lines	✓	✓	✓
H_2 pipelines		✓	✓
Bus-level independent components	✓	✓	✓
Hybrid energy hubs			✓

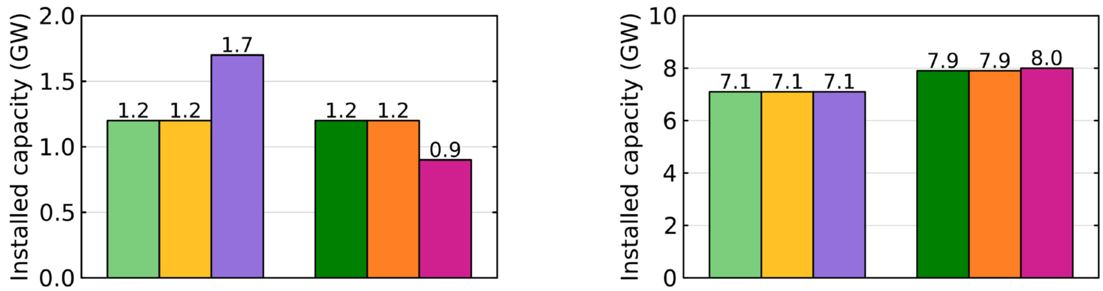
4.5.2 The impact of VRE droughts on investment decisions

The comparison of investment results under the Normal operation and the Resilience case studies under both scenarios are shown in Figure 4-16 and Figure 4-17 and summarised in Table 4-16 and Table 4-17. Further details on investment results in each REZ are provided in Appendix E. In general, the total system costs in the Resilience case study are higher than in the Normal operation case study because additional infrastructure are required to maintain reliable system operation during VRE drought events.



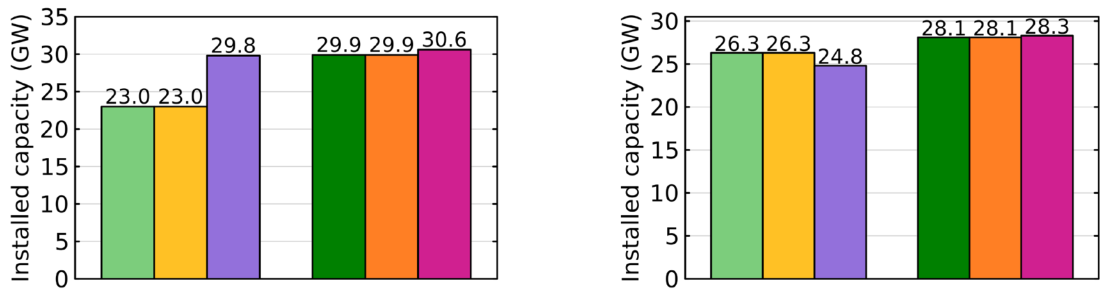
(a) Electricity lines

(b) H_2 pipelines



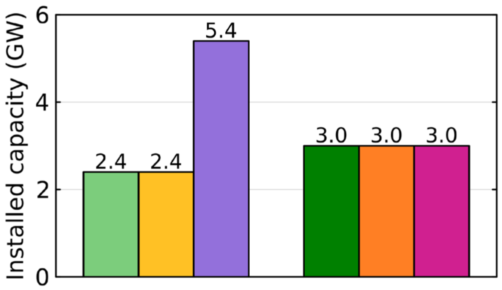
(c) REZ network expansion

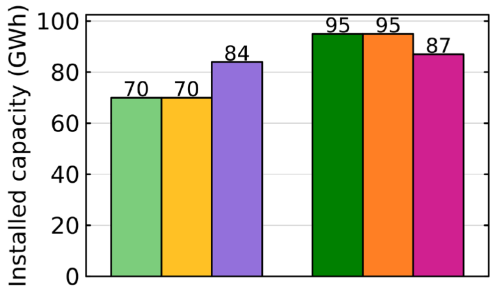
(d) Electrolysers



(e) Solar

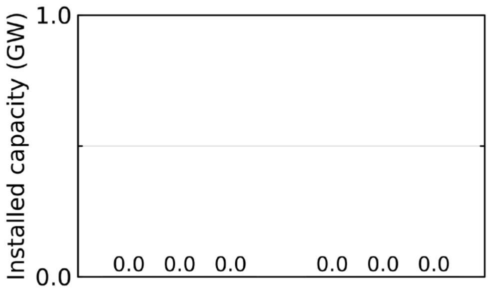
(f) Wind

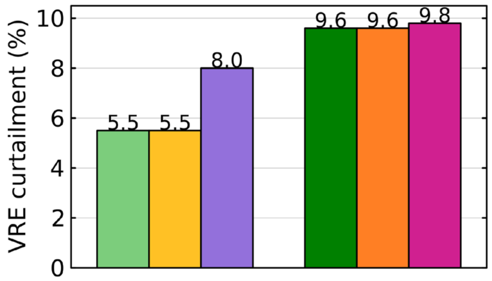




(g) BESS

(h) H_2 storage tanks





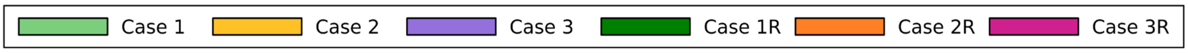
(i) H_2 turbines

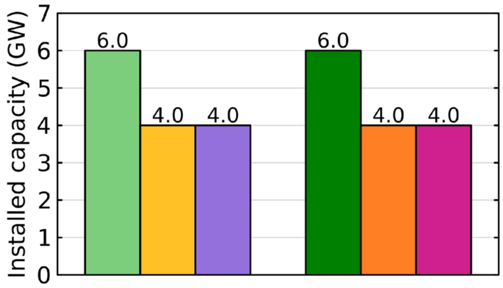
(j) VRE curtailment

Figure 4-16: Comparison of optimal investment results (a)-(i) and VRE curtailment (j) under the Step Change scenario under the Normal operation and the Resilience case studies.

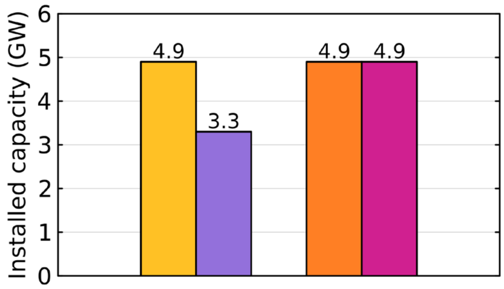
Table 4-16: Net present value of total costs in 2035 under the Step Change scenario under the Normal operation and the Resilience case studies.

	Operating cost (M$)	Annuitised investment cost (M$)	Total cost (M$)
Case 1-Base	2,251	4,164	6,415
Case 2-WithPipe	2,251	4,164	6,415
Case 3-Hubs	2,035	4,249	6,284
Case 1R-Base	1,871	4,753	6,624
Case 2R-WithPipe	1,871	4,753	6,624
Case 3R-Hubs	1,836	4,644	6,480

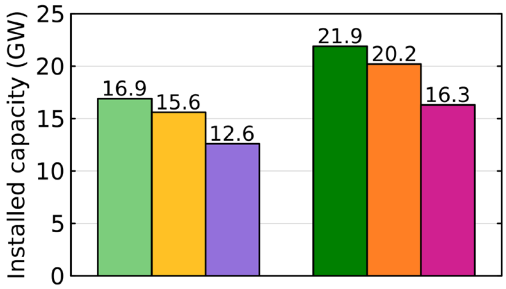




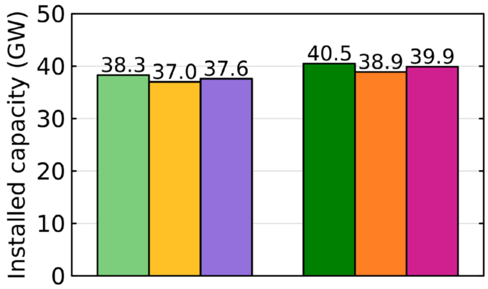
(a) Electricity lines



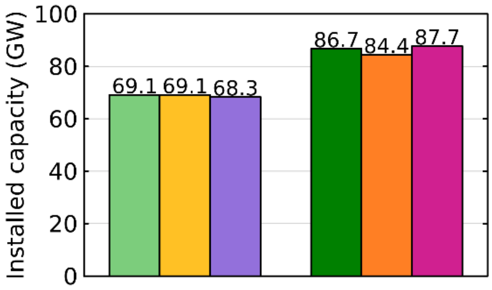
(b) H_2 pipelines



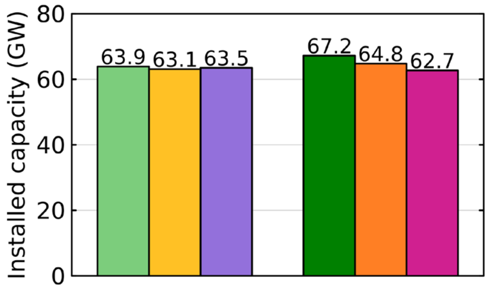
(c) REZ network expansion



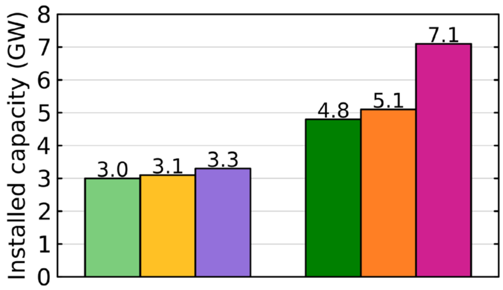
(d) Electrolyses

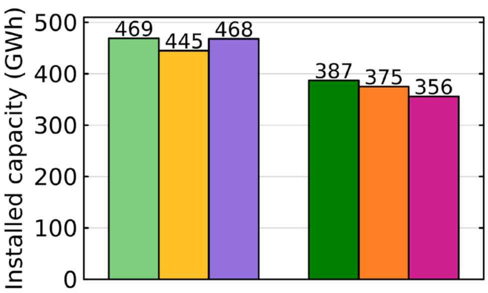


(e) Solar



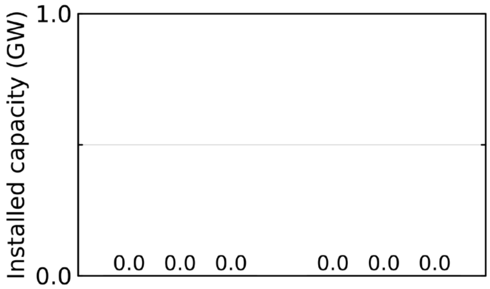
(f) Wind



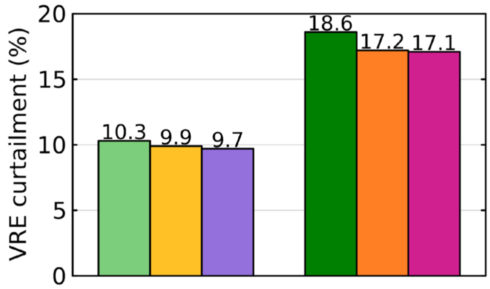


(g) BESS

(h) H_2 storage tanks



(i) H_2 turbines



(j) VRE curtailment

Figure 4-17: Comparison of optimal investment results (a)-(i) and VRE curtailment (j) under the Green Energy Exports scenario under the Normal operation and the Resilience case studies.

Table 4-17: Net present value of total costs in 2035 under the Green Energy Exports scenario under the Normal operation and the Resilience case studies.

	Operating cost (M$)	**Annuitised investment cost (M$)**	**Total cost (M$)**
Case 1-Base	2,287	11,033	13,320
Case 2-WithPipe	2,209	10,904	13,113
Case 3-Hubs	2,184	10,217	12,401
Case 1R-Base	1,692	12,517	14,209
Case 2R-WithPipe	1,727	12,159	13,886
Case 3R-Hubs	1,646	11,484	13,130

<u>Transmission and REZ network expansion investments</u>

As shown in Figure 4-16(a)-(b) and illustrated in Figure 4-18, transmission investments remain consistent between Cases 1 and 2 and their corresponding Cases 1R and 2R under the Step *Change* scenarios. However, Case 3R-Hubs includes an additional investment of 1.9 GW interconnector between South New South Wales and Victoria, compared to Case 3-Hubs, increasing inter-regional transfer capacity to support higher energy transport from the northern to the southern NEM during VRE drought conditions. Meanwhile, as shown in Figure 4-16(c), REZ network expansion in Case 3R-Hubs decreases by 0.8 GW compared to Case 3-Hubs, indicating that the increased interconnection capacity between regions reduces the need for local REZ network reinforcement. Despite the reduction in REZ network expansion, the overall capacity of electricity transmission and REZ network expansion increases by 1.1 GW. Additionally, H_2 pipelines are not selected under either the Normal operation or the Resilience case studies under the Step Change scenario, as the relatively low H_2 demand can be met through the local electrolysis production.

On the other hand, under the Green Energy Exports scenario, as shown in Figure 4-17(a)-(b) and illustrated in Figure 4-19, electricity line investments remain unchanged between all Normal operation cases and their corresponding Resilience cases. H_2 pipeline investments are also consistent between Case 2-WithPipe and Case 2R-WithPipe. However, Case 3R-Hubs invests in one additional H_2 pipeline between REZs T1 and T2 compared to Case 3-Hubs, improving H_2 transport and storage flexibility under VRE drought conditions. Additionally, as shown in Figure 4-17(c), REZ network expansion increases in all resilience cases under the Green Energy Exports, indicating the growing reliance on regional VRE generation to meet both electricity and H_2 demand during winter VRE drought events.

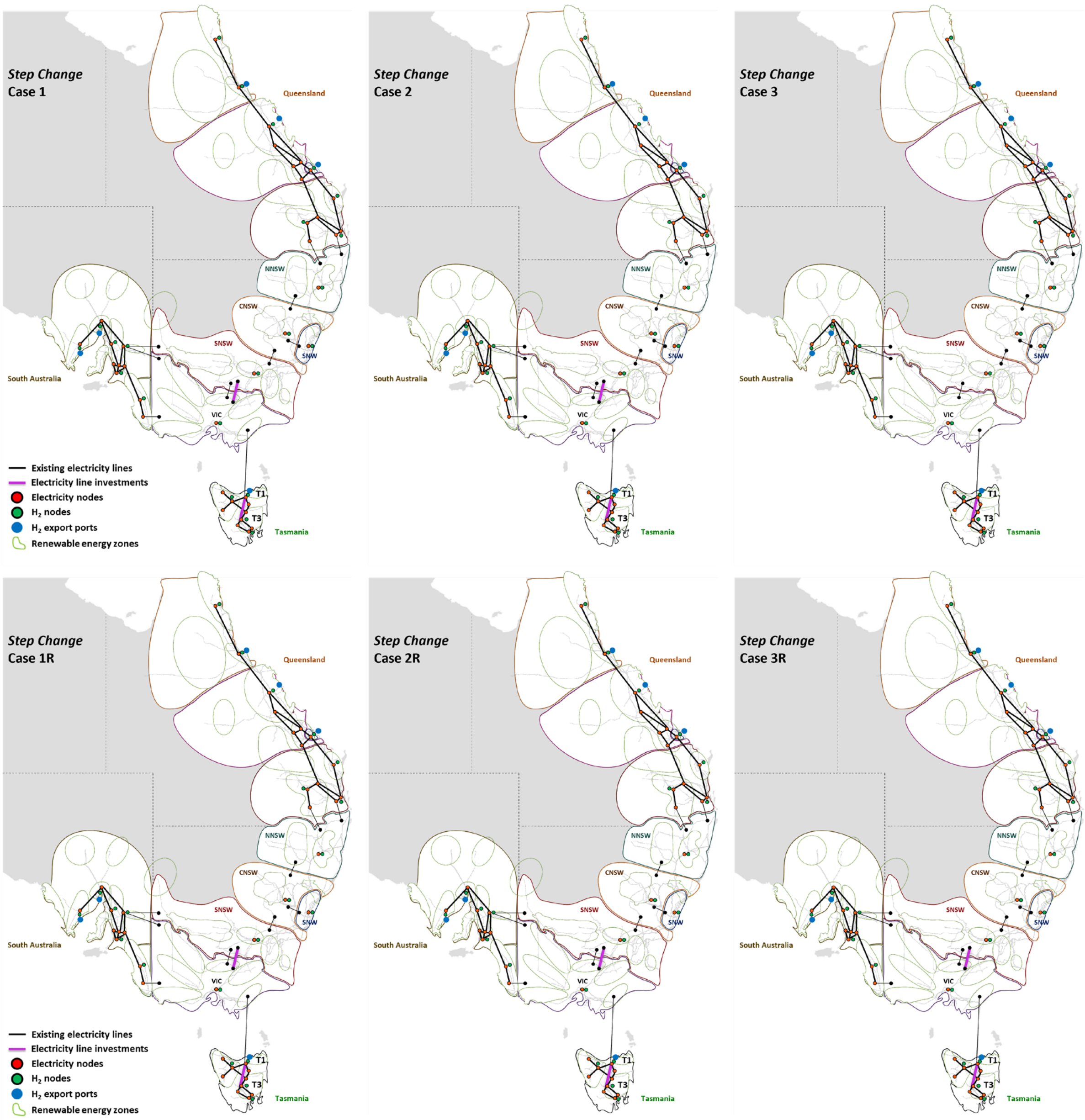


Figure 4-18: Comparison of transmission investment results under the Step Change scenario under the Normal operation and the Resilience case studies.

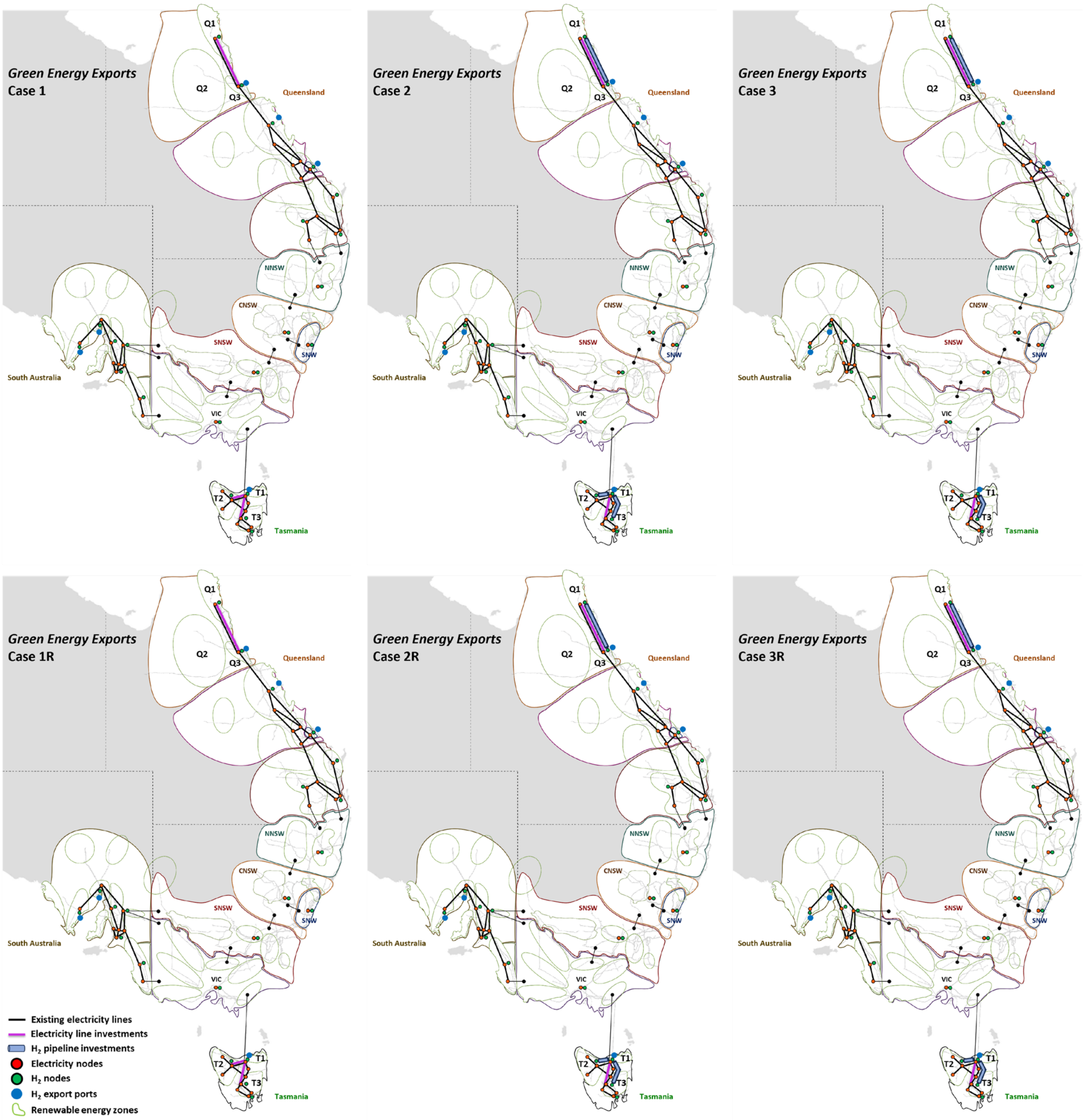


Figure 4-19: Comparison of transmission investment results under the Green Energy Exports scenario under the Normal operation and the Resilience case studies.

Electrolyser and VRE investments

As shown in Figure 4-16(d) and Figure 4-17(d), the capacities of electrolysers increase in all resilience cases under both *Step Change* and *Green Energy Exports* scenarios. This reflects the need for additional electrolysers to capture available VRE peaks during the VRE drought week and to maintain supply for fixed daily H_2 targets. Similarly, Figure 4-16(e)-(f) and Figure 4-17(e)-(f) show that total capacities of wind and solar increase across all resilience cases, with most of the additional investments located in the southern NEM as detailed in Table a-10 and Table a-11, where VRE generation is most constrained during the drought week. Specifically, under the Step Change scenario, both wind and solar investments increase in all resilience cases compared to the normal cases. Under the Green Energy Exports scenario, solar and wind investments rise in Case 1R-Base and 2R, while in Case 3R-Hubs, solar capacity increases but wind investment slightly decreases. Nevertheless, overall VRE capacity still increases in Case 3R-Hubs, indicating system-wide reinforcement of VRE supply to meet electricity and H_2 demand during winter VRE drought events.

BESS and H_2 storage investments

As shown in Figure 4-16(g) and Figure 4-17(g), the trends in BESS investments differ across scenarios. Under the Step Change scenario, the installed capacity of BESS remain unchanged between Case 1-Base and 1R, and between Case 2-WithPipe and 2R. However, in Case 3R-Hubs, BESS investment slightly decreases compared to Case 3-Hubs. This reduction can be attributed to the additional interconnector built in Case 3R-Hubs, which increases inter-regional electricity transfer and reduces the need for local short-term storage. In contrast, under the Green Energy Exports scenario, BESS investments increase in all resilience cases compared to their corresponding normal cases. As detailed in Table a-10 and Table a-11, most of the additional BESS capacities are invested in the southern NEM, where regions experience VRE drought, providing flexibility to manage short-term supply-demand imbalances.

For H_2 storage**,** opposite trends are observed across the two scenarios due to differences in system flexibility and cost assumptions. In the Step Change scenario, the capacity of H_2 storage increases in resilience cases despite relatively low H_2 demand. This is because the system invests in more VRE generation without expanding REZ network capacity, limiting the ability to transport electricity across regions during VRE drought week. As a result, local H_2 storage becomes essential to buffer intermittent supply and ensure reliable H_2 supply. Conversely, under the Green Energy Exports scenario, H_2 storage capacity decreases in the resilience cases, even though H_2 demand is significantly higher. As outlined in Table 4-6 and Table 4-7, compared to the Step Change scenario, the cost of REZ network reinforcement in most REZs and VRE investment costs are lower under the Green Energy Exports scenario, making it more economical to expand the REZ network and increase VRE generation. The resulting improvement in grid flexibility allows more VRE to be transported from REZs to the grid for H_2 production, reducing the need for additional local H_2 storage to buffer shortfalls.

H_2 turbine investments

Figure 4-16(i) and Figure 4-17(i) show that H_2 turbines are not selected even during VRE drought events. As indicated in Table 4-7, the high build costs and low round-trip efficiency of using electrolysers and H_2 turbines make this option less practical for supporting electricity supply. Instead, the model chooses to invest in more efficient and cost-effective BESS, which offers a more efficient and cost-effective solution to support the electricity system.

Overall system costs

Table 4-16 and Table 4-17 show that resilience cases under both scenarios see lower operating costs due to more use of VRE, enabled by higher investments in VRE capacity. However, this also leads to higher VRE curtailment during the four normal operation weeks, as shown in Figure 4-16(j) and Figure 4-17(j). Additionally, total investment costs increase in all resilience cases because of larger investments in electrolyser, total VRE generation, and total transmission and REZ network expansion. Overall system costs increase by approximately 3.1–3.3% in the Step Change scenario and 5.9–6.7% in the Green Energy Exports scenario when a VRE drought week is considered.

4.5.3 Merits of H_2 pipelines during VRE droughts

To understand the role of H_2 pipelines during VRE drought, analysis focuses on the comparison under the Green Energy Exports scenario, as H_2 pipelines are not selected for all normal operation and resilience cases under the Step Change scenario. First, Case 1R-Base and Case 2R-WithPipe are compared to assess how the inclusion of H_2 pipelines impacts system performance under resilience conditions. Second, a comparison between Case 3-Hubs and Case 3R-Hubs illustrates how H_2 pipeline investment shifts when resilience is explicitly considered.

Table 4-17 shows that compared to Case 1R-Base, which does not include H_2 pipeline options, Case 2R-WithPipe achieves the same level of system reliability without electricity or H_2 load shedding but at 2.3% lower total cost. This cost reduction is due to the added operational flexibility provided by H_2 pipelines which have both transport and storage capabilities as discussed in 0. By enabling H_2 to be transported from regions with more VRE availability, H_2 pipelines reduce the need to install additional VRE and electrolysers in regions with less available VRE. This flexibility reduces the pressure on the electricity transmission network, a benefit that becomes more important during VRE drought conditions. As a result, Figure 4-17(d)-(f) show that Case 2R-WithPipe mitigates the additional investments made in Case 1R-Base (relative to Case 1-Base) for resilience operation, reducing the installed capacities of electrolyser by 1.6 GW, solar by 2.3 GW, wind by 2.4 GW. The reduction of VRE generation also leads to 1.7 GW less REZ network expansion in Case 2R-WithPipe compared to Case 1R-Base, as seen in Figure 4-17(c).

Although linepack levels remain relatively flat during the VRE drought week, their value lies in providing spatial flexibility during VRE drought week. However, when combined with their storage flexibility utilised during the four normal operation weeks, the three installed H_2 pipelines in Case 2R-WithPipe displace 2GW of electricity lines and 12 GWh of H_2 storage tank, and reduce VRE curtailment by 1.4% compared to Case 1R-Base, as shown in Figure 4-17(a), (h), and (j). Additionally, the H_2 pipeline built between REZs Q1 and Q3 transports additional VRE from Q1 to Q3 for H_2 export, reducing southward electricity transmission for local demand. As a result, Case 2R-WithPipe increases investment in BESS by 0.2 GW in central and southern Queensland compared to Case 1R-Base, as shown in Figure 4-17(g) and detailed in Table a-11.

The comparison between Case 3-Hubs and Case 3R-Hubs further emphasises the role of H_2 pipelines in maintaining system resilience at lower costs. Figure 4-19 shows that compared to Case 3-Hubs, an additional H_2 pipeline between REZs T1 and T2 is selected in Case 3R-Hubs. This underscores the value of H_2 pipelines not only during normal operations but particularly under resilience scenarios that require the system to maintain reliability despite limited VRE availability. The transport flexibility provided by the additional H_2 pipeline during VRE drought week allows H_2 to be transported from REZ T2 with greater VRE availability to export port, avoiding the need to install additional local VRE and electrolysers in T1, where VRE resources are limited. This helps the system meet H_2 demand more cost-effectively under stress conditions.

Across both comparisons, H_2 pipelines maintain system resilience by enabling more flexible, spatially efficient energy transport during VRE drought week. This helps maintain system reliability at lower total system costs and VRE curtailment under VRE drought scenarios. These benefits might become even more pronounced in later years, given the projected rise in H_2 export targets [63].

4.5.4 Merits of hybrid energy hubs during VRE droughts

Comparison between Case 2R-WithPipe and Case 3R-Hubs under both scenarios is analysed to understand the role of hybrid energy hubs with shared connection assets in maintaining system resilience during VRE drought. Table 4-16 and Table 4-17 show that compared to Case 2R-WithPipe, Case 3R-Hubs sees a 2.2% reduction in total costs under the Step *Change* scenario, while under the *Green Energy Export* scenario, the cost reduction reaches 5.4%. These savings are achieved without any electricity or H_2 load shedding during the drought week, indicating that hybrid energy hubs maintain system resilience and reliability while reducing costs.

By co-locating VRE, electrolysers, and BESS, these hubs improve the integration of VRE supply, H_2 production, and electricity export to the grid more energy-efficiently. This more efficient configuration that leverages diversity reduces the total capacity of connection assets and improves operational flexibility during both the four normal operation weeks and the one VRE drought week. As a result, Figure 4-16(g)-(f) and Figure 4-17(d)-(f) show that under both scenarios, Case 3R-Hubs with energy hub options invests in more electrolyser and total VRE capacities to withstand the VRE drought week, compared to Case 2R-WithPipe. The increased capacities of VRE also lead to lower system operating costs in Case 3R-Hubs, with reductions of 1.9% under the Step Change scenario and 4.7% under the Green Energy Export scenario, as shown in Table 4-16 and Table 4-17. Moreover, the reduced costs of connection assets across the grid make hybrid energy hub a dominant investment choice in REZs by the model, as outlined in Table 4-18. As model invests in larger capacity of single technology at certain buses to maintain system reliability during VRE drought, a higher share of bus-level investments is seen in resilience studies compared to the normal operation studies under the Step Change scenario, as presented in Table 4-13.

Table 4-18: Percentage of bus-level and hub-level investments in REZs in Case 3R-Hubs under both scenarios under the Resilience case study.

Investments in REZs	Step Change scenario		Green Energy Exports scenario	
	Within energy hubs (%)	**At bus-level (%)**	**Within energy hubs (%)**	**At bus-level (%)**
Solar	85.9	14.1	97.4	2.6
Wind	91.7	8.3	97.5	2.5
BESS	95.8	4.2	100	0
Electrolyser	94.7	5.3	98.7	1.3

Meanwhile, Figure 4-16(c) and Figure 4-17(c) illustrate that under both scenarios, Case 3R-Hubs reduces the additional need for REZ network expansion in Case 2R-WithPipe that is required to meet demand under VRE drought conditions (relative to Case 2-WithPipe).

Specifically, Table a-10 shows that under the Step Change scenario, REZ N3 in Case 3R-Hubs requires less REZ network expansion even with a slight increase in wind capacity and no additional storage. This is because more energy is efficiently consumed within hubs in other regions, reducing the reliance on N3 to supply energy during peak hours. On the other hand, under the Green Energy Export scenario, hybrid hubs in Case 3R-Hubs lead to larger BESS investment within hubs compared to Case 2R-WithPipe, as shown in Figure 4-17(g) and Table 4-18. This added storage enhances local balancing, reducing peak power exports from REZs to the grids and thereby lowering REZ network expansion requirements in regions such as N3 and V6, as detailed in Table a-11.

Furthermore, in both scenarios, H_2 storage investment decreases with the introduction of hybrid hubs in Case 3R-Hubs compared to Case 2R-WithPipe, as show in Figure 4-16(h) and Figure 4-17(h). This is because the increased VRE capacity allows H_2 to be produced more consistently during the four normal operation weeks, making it possible to meet fixed daily H_2 demand without relying on local H_2 storage. However, under the Step Change scenario, the higher VRE investments also leads to a slight 0.2% increase in VRE curtailment in Case 3R-Hubs compared to Case2R, as shown in Figure 4-16(j). In contrast, Figure 4-17(j) shows that under the Green Energy Exports scenario, VRE curtailment decreases by 0.1% in Case 3R-Hubs compared to Case 2R-WithPipe. This is due to the additional BESS investment, which provide enhanced flexibility to absorb and shift surplus energy.

Overall, hybrid energy hubs with shared connection assets maintain system resilience under both scenarios at lower costs, reducing the need for REZ network expansion, and enabling more cost-effective operation during VRE drought week. Although Case 3R-Hubs involves higher build costs for investing in more capacities of VRE and electrolysers, these costs are offset by system-wide savings from shared connection assets, reduced REZ network expansion, and lower operating costs.

4.6 Key insights

The section introduces the modelling provides valuable insights into the impact of integrating H_2 pipelines and hybrid energy hubs into electricity-hydrogen system planning. Built on a modular energy hub modelling framework, the case studies capture how co-locating technologies and optimising both build and connection investments enhance system-wide performance under various operational and demand scenarios. Additionally, integrating hybrid energy hubs with transmission planning demonstrates how the inclusion of H_2 pipelines and hybrid energy hubs impact system operation and investment portfolios, while maintaining system resilience. The following key insights are summarised from the analysis:

I. ***Modular hybrid energy hub framework supports integrated and cost-effective electricity-hydrogen system planning:*** The modular energy hub modelling framework captures both build costs (main equipment) and connection costs (connection assets), along with REZ network expansion needs. The optimisation model evaluates both hybrid hub and independent (bus-level) investment options to identify the least-cost strategy which may co-locate technologies within a hub or invest separately at the bus level. The framework enables the design of renewable, hydrogen, or hybrid hubs and integrates electricity and hydrogen transmission planning, supporting more coordinated and efficient expansion of Australia's future energy system.

II. ***Hydrogen pipelines enhance system flexibility and reduce electricity transmission investments***: Incorporating H_2 pipelines into the planning framework enables spatial decoupling H_2 production from demand sites. By transporting H_2 from VRE-rich REZs to demand sites and storing surplus VRE generation through linepack, H_2 pipelines reduce the need for localised investments in electrolysers, VRE, and storage, as well as REZ network expansion. This contributes to lower VRE curtailment and overall system costs, particularly when large-scale H_2 demand is present.

III. ***Hybrid energy hubs enhance local integration and displace electricity-hydrogen transmission infrastructure***: By integrating H_2 production and storage with renewable generation, hybrid energy hub leverages the diversity across different technologies within a hub, which reduces the total capacity of connection assets. This also enables more efficient use of local VRE for H_2 production within hubs, reducing the need for additional electricity and H_2 transmission infrastructure and lowering overall system costs.

IV. ***Hydrogen pipelines maintain system resilience at lower costs:*** Under the Green Energy Exports scenario, compared to Case 1R-Base, Case 2R-WithPipe maintains reliable energy supply at up to 2.3% lower total system costs, while also reducing VRE curtailment and displacing electricity line and storage investments. The transport capability of H_2 pipelines, along with additional stationary H_2 storage in key locations, ensures that H_2 can be transported from the regions with better VRE resources to demand sites.

V. ***Hybrid energy hubs maintain resilience at lower costs:*** Compared to Case 2R-WithPipe, the inclusion of hybrid energy hubs in Case 3R-Hubs enables more cost-effective use of available VRE for electricity generation and H_2 production during VRE droughts, thereby reducing REZ network expansion. Although higher build costs arise due to increased VRE and electrolyser investments when hybrid energy hub options are included, these are offset by shared connection assets, reduced network expansion needs, and lower system operating costs. Case 3R-Hubs achieves a reduction in total system costs of 2.2% under the Step Change scenario and of 5.4% under the Green Energy Exports scenario, compared to Case 2R-WithPipe.

5 Conclusions

This report provided an in-depth analysis of methodological approaches to improve the integration of energy systems regarding modelling improvements, computational requirements, and technological representations. Different techno-economic assessments were carried out in instances of the National Electricity Market (NEM) to illustrate the benefits of advanced planning models to value flexible technologies under different operational conditions. These allowed for identifying the potential benefits, challenges, and impacts on integrated energy system planning through increased and enhanced operational flexibility provided by active distribution systems planning and DER, and the integration and coupling of electricity-hydrogen infrastructure.

This research underscored the following insights from integrated planning:

- Integrated planning of transmission and distribution systems shows significant promise to deliver cost-efficient developments for future power systems, as well as capture trade-offs between large- and small-scale resources in a coordinated fashion. Based on this, methodologies that support *parallel and distributed computing* allow for manageable planning formulations that can leverage the know-how capabilities of system operators and planners. Thus, such approach has the potential to facilitate real-world applicability of integrated transmission and distribution planning as it does not require huge regulatory changes.
- The proposed methodology for planning active distribution networks allows for quantifying investment costs to support DER though a bottom-up approach where information can be exchanged from LV to MV to HV. Additionally, it captures network limitations and DER's active power dynamic flexibility through an equivalent model that allows for reducing the modelling requirements of active distribution systems in transmission planning.
- The coordination of DER has the potential to enhance overall system flexibility, leading to a reduction of capital-intensive investments on distribution and transmission infrastructure that could become stranded. Also, by integrating distribution network planning, the DER flexibility that is available upstream the network is quantified in both, investment costs and operational limitations. Moreover, the available resources are optimally managed, making consumption patterns at the interface with the NEM more efficient, reducing peak load and DER energy curtailment, reducing operational costs as result.
- Although this project used representative networks to showcase the applicability of the methodology for planning active distribution networks, considerations of MV-LV

networks are needed as ignoring these could lead to inaccurate DER hosting capacity and/or required network investments projections. In this sense, there will be trade-offs between investments and DER coordination for local services.

- Hybrid energy hubs with shared connection assets reduce costs by leveraging diversity across different technologies within a hub. This can reduce the total capacity of connection assets. A modular and scalable framework is needed for the design and assessment of these hubs, enabling flexible and cost-effective integration of components. A comprehensive planning framework is needed to integrate transmission planning with hybrid energy hub design to provide valuable insights into cost-effective strategies for expanding the energy system while maintaining system reliability and resilience.
- The proposed modular framework for hybrid energy hub design captures both build costs (e.g. VRE, electrolysers, BESS) and shared connection assets (e.g. transformers, feeders), allowing the model to evaluate both hub-level and bus-level investment options. By jointly optimising the design of hybrid energy hubs with electricity and H_2 transmission expansion, the model enables more coordinated, spatially efficient, and cost-effective planning results that better reflect the economic and operational benefits of co-located infrastructure and integrated system development.
- H_2 pipelines increase system-wide flexibility and reduce the need for localised electricity infrastructure by enabling spatial decoupling of H_2 production and demand. Through linepack storage and long-distance transport, pipelines allow excess VRE generation in REZs to be utilised for H_2 production, reducing the need for local electrolysers, BESS, and transmission expansion. The inclusion of H_2 pipelines in system planning reduces VRE curtailment and supports a more resilient and cost-efficient system under high H_2 demand scenarios.
- Hybrid energy hubs enhance local energy integration and displace the need for electricity and H_2 transmission infrastructure. By integrating VRE, electrolysers, and storage within a hub and sharing connection assets, the hubs reduce total costs of connection assets. Integrated with transmission planning, hybrid hubs enable more efficient use of local resources, reduce REZ network expansion, and support more reliable H_2 and electricity supply during VRE droughts.

Overall, this research underscored the importance of integrated planning, as well as the need for methodologies to adequately quantify the considerable benefits that the flexibility from distribution networks and hybrid energy hubs could provide to improved decision-making and system operation. Moreover, to inform decision-makers with key insights about highly integrated, low-carbon energy systems, it is crucial to advance to modelling that captures the risks and uncertainties inherent in highly integrated and weather-dependent power systems.

Active distribution network planning

This report proposes a novel methodology for integrated transmission and distribution planning based on distributed decision-making between system planners. By enabling a limited exchange of information through parametric investment cost functions that embed both network investments and DER adoption, characterising the flexibility unlocked to the transmission system based on these scenarios (e.g., pair of investments and DER adoption). It aligns with current planning roles, leveraging the know-how capabilities of system planners while enhancing coordination by producing this additional information. In this sense, through the steps outlined in this report (e.g., investment and operational frameworks), DNSPs could facilitate representing the planning of their networks as investment options within transmission planning frameworks, thereby supporting more holistic and informed system-wide decision making.

Case studies validate the value of this approach, revealing that optimal DER allocation significantly reduces total distribution investment costs compared to uniform DER deployment across the network. They also show that granular, proactive planning, especially when incorporating non-network solutions like storage or reactive power compensation, enhances the hosting capacity of distribution systems and defers costly network reinforcements.

Moreover, curtailment emerges as a critical element in the planning of distribution networks. Analyses of varying curtailment levels demonstrate that allowing some degree of active DER management can meaningfully postpone infrastructure investments, highlighting the value active network management for planning purposes. It was also concluded that, even though, *customer export curtailment value* (CECV) is a useful proxy, coordinated planning between transmission and distribution systems is necessary to determine the most cost-effective level of curtailment from a whole-system perspective.

From an operational point of view, *nodal operating envelopes* (NOEs) is an efficient approach to dynamically characterise both distribution network limitations and DER flexibility. As more DER is integrated, both active and reactive flexibility increase due to portfolios of investments that combine network and non-network technologies. This reinforces the need for DNSPs to evolve toward more active management strategies and to use such planning outputs to inform transmission operators like AEMO. From these NOEs, an equivalent model was proposed to represent distribution networks as a generator, flexible load, and storage components, mapping active power flexibility as a means of modelling them within transmission planning frameworks.

By employing the proposed methodology, substantial benefits were found in real-world planning scenarios across Victorian subtransmission networks. Coordinated CER were shown to cut infrastructure investment needs by up to 90% in some rural areas. These cost savings are attributed to the local flexibility unlocked from CER coordination, which solves local issues such as congestions and voltage constraints, which in turn defers investments. When scaled to the entire state of Victoria, the aggregated results suggest that achieving full CER coordination by 2040 or 2050 could reduce overall distribution infrastructure investments by approximately 50%.

The integration of this distribution planning methodology within transmission planning models, tested through "representative networks" for subregions of the NEM, demonstrates both its practicality and potential. Even with simplified assumptions, the inclusion of DER coordination through the equivalent model, leads to system-wide benefits, such as deferral of transmission augmentations, reduced curtailment, and lower total costs. These findings underscore the value of embracing integrated planning practices that leverage distribution-level flexibility while valuing the investments needed to unlock those levels, and more efficiently guide the development of future energy systems across Australia.

Finally, although these case studies show the applicability of the proposed methodology, there's a need to understand the limitations and investments needed within distribution networks across all levels, that is LV, MV, and HV, but also across all subregions of the NEM. This is truly important as the flexibility from DER can be overestimated, particularly CER such as EVs, DHW, distributed batteries, that could be constrained by limitations within MV-LV networks unless proper investments are made. Thus, there will be a trade-off between distribution investments and the provision of local services by CER, and this balance will depend heavily on the objective function of the distribution planning approach, aspect that can be explored by the proposed methodology. Nevertheless, it has been shown, that the most benefits do come when 100% of CER is coordinated, suggesting the need for incentivising this development.

Hybrid energy hubs for electricity-hydrogen planning

This report presents a modular energy hub modelling framework designed to support integrated planning of electricity and H_2 infrastructure. The framework explicitly captures both the build costs of major equipment and the costs of connection assets. By evaluating both hub-level and independent bus-level investment options, and integrating electricity and H_2 transmission planning, the model enables a more coordinated and cost-effective approach to system development.

A series of case studies applied on the NEM involving REZs are conducted to assess the role of H_2 pipelines and hybrid energy hubs under varying H_2 demand and operational scenarios, including resilience conditions such as VRE droughts. The results show that integrating these components can significantly improve system-wide performance, reduce total costs, and maintain resilience.

H_2 pipelines improve system flexibility by enabling spatial decoupling of H_2 production and demand. They allow surplus VRE in resource-rich REZs to be stored and transported to demand sites, reducing the need for additional investments in electrolysers, VRE, and BESS at export sites. Under the Normal operation case study, this lowers overall system costs by 1.6%, reduces VRE curtailment, and mitigates the need for REZ transmission expansion under the Green Energy Exports scenario. Under the Resilience case study, H_2 pipelines can maintain reliable H_2 supply with lower costs, while also reducing VRE curtailment and displacing electricity line and storage investments. This results in a 2.3% reduction in total system costs under the Green Energy Exports scenario.

Hybrid energy hubs with shared connection assets that leverage diversity enhance local integration by co-locating VRE, electrolysers, and storage technologies. Under the Normal operation case study, this reduces the need for electricity and H_2 transmission infrastructure and improve existing asset utilisation. As a result, total system costs reduce by 2.0% under the Step Change scenario and by 5.7% under the Green Energy Exports scenario. Under resilience conditions, hybrid energy hubs support greater investment in local VRE and H_2 production, making better use of available local VRE resources and reducing the need for REZ transmission expansion. This improved spatial and temporal coordination helps maintain energy supply during renewable shortfalls and contributes to a more robust energy system. This results in a 2.2% cost reduction under the Step Change scenario and a 5.4% reduction under the Green Energy Exports scenario.

In summary, this study demonstrates that integrating H_2 pipelines and hybrid energy hubs into electricity–hydrogen system planning can improve overall system performance under both normal and resilience conditions. H_2 pipelines are selected as more cost-effective alternatives to electricity transmission lines, decoupling H_2 production from demand sites and providing linepack storage during normal operation weeks. Hybrid energy hubs with shared connection assets leverage diversity across different technologies within a hub, enabling more cost-effective use of available VRE for electricity generation and H_2 production, while reducing the need for electricity and H_2 transmission infrastructure.

6 Recommendations for future work

Following recent in-person events held at the CSIRO Energy Centre and the publication of updated research priorities by AEMO and the International System Operator Network (ISON), there is increasing focus on bridging research and real-world applications in engineering, planning, and system operability. In particular, under the "Planning" topic, there is significant interest in advancing methodologies and developing open-source, scalable, and computationally efficient tools for adequacy and strategic planning studies. These efforts should aim to address the operational challenges of an increasingly weather-dependent energy system with high levels of storage and DER integration. Moreover, these priorities are aligned with previous recommendations and the long-term research strategy outlined for Topic 4. Based on this, the focus should be on the following research activities from the original research plan:

- ***R1S2P1**: Modelling of climate change for power system planning with different purposes (different types of events, spatio-temporal representation, probabilities, correlation, etc.)*
- ***R2S1P1**: Modelling the steady state of the system considering the trade-off between computational efficiency and model precision.*
- ***R3S1P1**: Developing new metrics to quantify the benefits to reliability and resilience associated with the investments in new system assets.*
- ***R3S2P1**: Assessing the reliability and resilience of power system considering the impact of climate change and extreme weather conditions on its infrastructure components*
- ***R3S3P2**: Profiling power system risks under various contingencies and indistinct events for future low-carbon grid with high penetration of IBR/DERs.*
- ***R3S4P1**: Modelling and analysing the impact on planning from IBR (including and in particular batteries) response to credible contingencies and high impact low probability (HILP) events.*
- ***R3S4P2**: Modelling and analysing the impact on planning from DERs and distribution network assets response to credible contingencies and high impact low probability (HILP) events.*
- ***R5S3P2**: Modelling and analysing the contribution of DERs to system reliability (security and adequacy) and resilience.*

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Appendix A Mathematical formulation for distribution systems' parametric investment cost functions

This section details the mathematical model to construct the parametric investment cost function for distribution systems. The model minimises the present value of investments and operational costs to support a certain DER adoption (parameter of the problem) and thus, it must be computed for all levels within the parametrisation chosen by the system planner. Also, for simplicity, the index associated to representative periods is included in index *t,* which represents all time-steps.

Thus, the objective function is presented in equation (1). More in detail, investments considered in this project are network reinforcements, active network management in the form of reactive compensation and CER coordination (when analysed as curtailment, coordination, etc.), and distributed storage as in (2). Operational costs are associated to non-renewable distributed generation, curtailment of renewable distributed generation, demand response schemes, and to the power exchanged with the upstream network, which is penalised by a cost α_t[14] that incentivises exports from DER technologies, as seen in (3).

$$\min \quad \frac{C_n^{INV}(x_n^{INV}) + C_n^{op}(x_n^{OP})}{(1+r)^{V_n}} \tag{1}$$

$$C_n^{INV}(x_n^{INV}) = \sum_{l \in L} C_L^{INV} x_l^L + \sum_{a \in ANM} C_{ANM}^{INV} x_a^{ANM} + \sum_{s \in STG} C_{STG}^{INV} x_s^{STG} \tag{2}$$

[14] We could assume that this cost is the market clearing price, however negative costs would cause the overinvestment in distributed storage, which may not be needed to support expected DER or CER, making the distribution system act as a price-taker. This is not ideal as we don't know prices for the future. Thus, it is assumed to penalise rather than a cost, just to incentivise the operation of DER through investments.

$$C_n^{op}(x_n^{OP}) = N\sum_{t\in T}\left(\sum_{g\in G^{NVRE}} C_t^{NonVRE} p_{g,t}^{NonVRE} + \sum_{g\in G^{VRE}} C_t^{Curt}(Gen_{g,t}^{VRE} - p_{g,t}^{VRE}) + \sum_{d\in DR} C_t^{DR}(pshup_{d,t} + pshdn_{d,t} + pred_{d,t}) + \sum_{b\in TSO-DSO} \alpha_t pcc_{b,t}^{TSO-DSO} + VOLL\sum_{b\in B} ENS_{b,t}\right) \quad (3)$$

Table a-1: Description of variables to define the objective function to find a parametric investment cost function for distribution systems.

Variable	Description
$x_l^L, x_a^{ANM}, x_s^{STG}$	**Binary or integer investment decision variable** for network reinforcements (binary), active network management (integer) and storage (integer)
$C_d^{INV}(X^{INV}), C_d^{op}(X^{OP})$	Investment and operational costs associated to the planning of a distribution system *d*
$pred_{d,t}, pshup_{d,t}, pshdn_{d,t}$	**Decision variable** for reduction, upward and downward for flexible demand *d* in time step *t*
$Gen_{g,t}^{VRE}, Gen_{g,t}^{NonVRE}$	Generation limits for renewable and non-renewable component of equivalent model for distribution planning scenario *p* in time step *t*
C_t^{NonVRE}, C_t^{Curt}	Operational cost of non-renewable DER and curtailment of renewable DER
$p_{g,t}^{VRE}, p_{g,t}^{NonVRE}$	**Decision variable** for renewable and non-renewable generation component, for distribution system *d* in time step *t*
$pcc_{b,t}^{TSO-DSO}$	**Decision variable** for the power exchanged between transmission and all the interfaces *b* of the distribution system, for each time step *t*
$ENS_{b,t}, VOLL$	**Decision variable** on energy not supplied at bus *b*, time step *t,* which is valued at the value of lost load, or market cap for the NEM

Perhaps the most important constraint of this formulation is presented in (4), where the total accessible DER capacity (existing and investments in the form of CER coordination, considered as) must be greater or equal to each value within an array of potential DER capacities (DER_p^{ADOP}), also referred as parametric adoption. Therefore, this constraint changes every time we compute this planning problem.

$$\sum_{g\in G} Cap_g^{INST} + \sum_{s\in STG} Cap_s^{INST} + \sum_{d\in DR} Cap_d^{INST} + \sum_{k\in CER} Cap_k^{INV} x_a^{ANM} \geq DER_p^{ADOP} \tag{4}$$

Table a-2: Description of variables for DER adoption constraint.

Variable	Description
$Cap_g^{INST}, Cap_s^{INST}, Cap_d^{INST}$	Installed capacity of distributed generators *g*, storage *s*, and demand response *d*
DER_p^{ADOP}	DER capacity to support through investments, in index *p* within the parametrisation

Moreover, the technical limits of each DER technology are considered as well. Equation (5) to (8) model the storage systems, particularly charge and discharge power limits, as well as the state of charge. It must be noted that a binary variable is included as well to avoid charging and discharging at the same time-step, and that storage as CER is modelled in the same way, but instead of x_s^{STG}, it considers x_d^{ANM} as investment decision variable for coordination. Moreover, the reduction, upward and downward shifting power limits for demand response are determined by equations (9) to (11), and in addition, equation (12) models the need to recover the energy from this service, with the corresponding payback PB_d, for all time blocks defined by the recovery time parameter. Finally, distributed generation is limited as seen in equations (13) and (14).

$$bl_{s,t} \leq P_s^{ch,STG} x_s^{STG} \tag{5}$$

$$bp_{s,t} \leq P_s^{dch,STG} x_s^{STG} \tag{6}$$

$$E_s^{Min} x_s^{STG} \leq se_{s,t} \leq E_s^{Max} x_s^{STG} \tag{7}$$

$$se_{d,t} = se_{d,t-1} + bl_{d,t}\mu - \frac{bp_{d,t}}{\mu} \tag{8}$$

$$pred_{d,t} \leq L_d^{Red} x_d^{ANM} \tag{9}$$

$$pshup_{d,t} \leq L_d^{Up} x_d^{ANM} \tag{10}$$

$$pshdn_{d,t} \leq L_d^{Dn} x_d^{ANM} \tag{11}$$

$$\sum_{t\in RT_d} pshup_{d,t} = PB_d \sum_{t\in RT_d} pshdn_{d,t} \tag{12}$$

$$p_{g,t}^{VRE} \leq Gen_{g,t}^{VRE} \tag{13}$$

$$p_{g,t}^{NonVRE} \leq Gen_{g,t}^{NonVRE} \tag{14}$$

Table a-3: Description of variables for active power technical limits of DER.

Variable	Description
$P_s^{ch,STG}, P_s^{dch,STG}, E_s^{Max}, E_s^{min}$	Power and storage limits for distributed storage *s*, existing or investment option
$bl_{s,t}, bp_{s,t}, se_{s,t}$	**Decision variable** for charging, discharging and energy stored of distributed storage *s*, in time step *t*
$L_d^{Up}, L_d^{Dn}, L_d^{Red}$	Power limits for demand response *d*, shifting upwards and downwards, and reduction
$RT_{p,DR}, PB_{p,DR}$	Recovery time, and payback parameter for aggregated demand response services, represented by the equivalent model
$pred_{d,t}, pshup_{d,t}, pshdn_{d,t}$	**Decision variable** for reduction, upward and downward for flexible demand *d* in time step *t*
$Gen_{g,t}^{VRE}, Gen_{g,t}^{NonVRE}$	Generation limits for renewable and non-renewable component of equivalent model for distribution planning scenario *p* in time step *t*
$p_{g,t}^{VRE}, p_{g,t}^{NonVRE}$	**Decision variable** for renewable and non-renewable generation component, for distribution system *d* in time step *t*

Also, DGs, storage and reactive compensation investment units can inject or consume reactive power, having a positive and negative limit respectively, as seen in equations (15) to (17). Particularly, for DGs and storage we fixed a power factor for simplicity as this would depend entirely on technical capabilities of the asset and inverter.

$$-Q_s^{STG} x_s^{STG} \leq q_{s,t}^{STG} \leq Q_s^{STG} x_s^{STG} \tag{15}$$

$$-Q_k^{SVC} x_k^{ANM} \leq q_{k,t}^{SVC} \leq Q_k^{SVC} x_k^{ANM} \tag{16}$$

$$-Q_g^{GEN} \leq q_{k,t}^{GEN} \leq Q_g^{GEN} \tag{17}$$

Table a-4: Description of variables for reactive power technical limits of DER.

Variable	Description
$Q_s^{STG}, Q_k^{SVC}, Q_g^{GEN}$	Reactive power limits for storage s, static VAR compensator k, and distributed generator g
$q_{s,t}^{STG}, q_{k,t}^{SVC}, q_{k,t}^{GEN}$	**Decision variable** for reactive power for storage s, static VAR compensator k, and distributed generator g

Then, this framework employs a linearised AC power flow (LinDistFlow reactive power and voltage play a huge role in the operation of distribution networks. This includes as variables the active and reactive power, as well as the voltages at each bus of the network, as seen in equation (18). Moreover, a linearised relationship between active and reactive power is employed as in (19), where Υ_c^P and Υ_c^Q are parameters based on tangential cuts to the real quadratic relationship [74].

$$- BigM\,(1 - x_l^L) \leq v_{to(l),t} - v_{from(l),t} + 2\left(R_l f_{l,t}^P + X_l f_{l,t}^Q\right) \leq BigM\,(1 - x_l^L) \tag{18}$$

$$\Upsilon_c^P f_{l,t}^P + \Upsilon_c^Q f_{l,t}^Q \leq x_l^L S_l^L \tag{19}$$

Table a-5: Description of variables for linear AC power flow.

Variable	Description
$v_{b,t}$	Voltages at bus *b,* in time step *t*
$f_{l,t}^P, f_{l,t}^Q$	**Decision variable** for active and reactive power flow through line *l* at time step *t*
S_l^L	Apparent power, or thermal limit of distribution line *l*
$\Upsilon_c^P, \Upsilon_c^Q$	Parameters for linearised relationship between active, reactive and apparent power, used for modelling thermal limits
R_l, X_l	Resistance and reactance of distribution line *l*

Then, there is the nodal balance which includes energy not supplied. This is modelled for active and reactive power, where the load has a fixed power factor as well (consumption of reactive power). Also, in those buses where the distribution system is connected to the upstream network, there's the possibility of exchanging both active and reactive power ($pcc_{b,t}^{TSO-DSO}$ and $qpcc_{b,t}^{TSO-DSO}$), as seen in equations (18) and (19).

$$\sum_{g\in G_b}(p_{g,t}^{VRE}+p_{g,t}^{NonVRE})+\sum_{s\in STG_b}(bp_{s,t}-bl_{s,t})+\ pcc_{b,t}^{TSO-DSO}+\sum_{l\in\mathcal{L}_b^{from}}f_{l,t}^{P}-\sum_{l\in\mathcal{L}_b^{to}}f_{l,t}^{P}$$
$$=Load_{b,t}^{P}-ENS_{b,t}+\sum_{d\in DR_b}(pshup_{d,t}-pshdn_{d,t}\ -pred_{d,t}) \quad (20)$$

$$qpcc_{b,t}^{TSO-DSO}+\sum_{g\in G_b}q_{g,t}^{GEN}+\sum_{k\in ANM_b}q_{k,t}^{SVC}+\sum_{s\in STG_b}q_{s,t}^{STG}+\sum_{l\in\mathcal{L}_b^{from}}f_{l,t}^{Q}-\sum_{l\in\mathcal{L}_b^{to}}f_{l,t}^{Q}=Load_{b,t}^{Q} \quad (21)$$

Finally, this same model is employed for the operational framework. The difference is in that the investment decisions are fixed, that the objective function changes depending on the purpose (i.e., base operation, imports, and exports), and that any intertemporal constraint (e.g., state of charge) is neglected when analysing imports and exports, as we try to capture the flexibility in terms of power to find time-varying limits for the components of the equivalent model. Thus, for the base operation, we only minimise the operational costs (including the penalisation for exchange with the upstream network) as seen in (3). For imports and exports we maximise and minimise, respectively, the variable $pcc_{b,t}^{TSO-DSO}$.

Appendix B Mathematical formulation to find equivalent operational model to represent flexibility of distribution systems

This section delves into the mathematical formulation employed to find the equivalent model of distribution system proposed in this work. As reference, this equivalent model only characterises the active power of each component, and although reactive power is part of the distribution planning and operational mathematical formulations (any operational state considers reactive power limitations), as seen in the Appendix A, the flexibility that DER and distribution systems can provide in terms of reactive power is neglected when integrated into the transmission planning problem because reactive power is typically not modelled in transmission systems, as a DC power flow is sufficient (no reactive power with voltages assumed to be 1 p.u.).

As context, the following illustration shows a dynamic representation of the active power associated to the operating envelope, for each time step, of a distribution network. Here, the base operation, maximum and minimum consumption (imports and exports respectively) allow for capturing the time-varying parameters for the equivalent model are determined by analysing the upwards (green arrows) and downwards (orange arrows) flexibility (operational headroom) of DER. On the one hand, *flexibility towards imports* is associated to curtailment, charging storage systems, and any demand response scheme that increases load. On the other hand, *flexibility towards exports* is associated to additional generation, discharge of storage systems, and any load shedding demand response scheme.

Figure a-1: Characterisation of equivalent model according to dynamic active power operating envelope.

Thus, the set of equations to compute this equivalent representation of the operational capabilities of distribution networks is described in this section. These depend on the variables that are detailed in the following table.

Table a-6: Description of variables to find equivalent model of distribution systems.

Variable	Description
$P_{ch,t}^{Eq,BESS}$	Charging limit of aggregated storage component
$P_{dch,t}^{Eq,BESS}$	Discharging limit of aggregated storage component
$P_{b,t}^{ch,Imp}, P_{b,t}^{dch,Imp}$	Charging and discharging of individual distributed storage *b*, at time *t*, for the imports case
$P_{b,t}^{ch,Base}, P_{b,t}^{dch,Base}$	Charging and discharging of individual distributed storage *b*, at time *t*, for the base case
$P_{b,t}^{ch,Exp} - P_{b,t}^{dch,Exp}$	Charging and discharging of individual distributed storage *b*, at time *t*, for the exports case
$InstESS_b^{Base}, minESS_b^{Base}$	Installed and minimum storage capacity (MWh) for distributed storage *b*
E_{max}, E_{min}	Storage limits (MWh) of the aggregated storage component
$L_{DR,,t}^{Imp}$	Demand response scheme for flexible load *DR*, at time *t,* for imports case
$L_{DR,t}^{Base}$	Demand response scheme for flexible load *DR*, at time *t,* for base case
$L_{DR,t}^{Exp}$	Demand response scheme for flexible load *DR*, at time *t,* for exports case
$L_{up,t}^{Eq,DR}, L_{dn,t}^{Eq,DR}$	Power limits for aggregated demand response, upwards and downwards at time *t*
$C_{Eq,DR}, RT_{Eq,DR}, Payback_{Eq,DR}$	Cost, recovery time, and payback parameter for aggregated demand response services, represented by the equivalent model
$P_{Imp,t}^{TSO-DSO}$	TSO-DSO power exchange, imports case, at time *t*
$Load_t$	Inflexible load of the equivalent model at time *t*
$Gen_t^{VRE}, Gen_t^{NonVRE}$	Generation limits at time *t*, for renewable and non-renewable component of equivalent model
$Gen_t^{Exp,VRE}, Gen_t^{Imp,VRE}$	Generation of all renewable DER at time t, for exports and imports case
$Gen_t^{Exp,NonVRE}, Gen_t^{Imp,NonVRE}$	Generation of all non-renewable DER at time t, for exports and imports case
C_{NonVRE}	Operational cost of non-renewable DER

C_{Curt}^{VRE}	Curtailment cost of renewable DER

First, equations (22)-(25) determine the parameters associated to the storage component of the distribution system. To find the equivalent charge and discharge capacity for each time-step and all analysed scenarios, the base operation of aggregated BESS is compared with the operation of the same aggregated BESS but in the imports and exports case respectively. In this sense, the principle is to understand how aggregated BESS can change their power towards imports and exports in each time-step, which will be limited by either their rated capacity or if there are any network constraints (voltages or thermal limits). As for the storage, this is equivalent to the sum of all the available storage within the system.

$$P_{ch,t}^{Eq,BESS} = \sum_{b}^{BESS} (P_{b,t}^{ch,Imp} - P_{b,t}^{dch,Imp}) - (P_{b,t}^{ch,Base} - P_{b,t}^{dch,Base}) \tag{22}$$

$$P_{dch,t}^{Eq,BESS} = \sum_{b}^{BESS} (P_{b,t}^{dch,Exp} - P_{b,t}^{ch,Exp}) - (P_{b,t}^{dch,Base} - P_{b,t}^{ch,Base}) \tag{23}$$

$$E_{max} = \sum_{b}^{BESS} InstESS_{b}^{Base} \tag{24}$$

$$E_{min} = \sum_{b}^{BESS} minESS_{b}^{Base} \tag{25}$$

Employing the same comparison, the time-varying parameters of demand-response schemes are determined based on equations (26)-(30). This refers to schemes associated to load reduction or increased. In the case of load shifting, an additional parameter is considered as recovery time, which indicates the time block in which load that was previously reduced, needs to be recover, including a payback as efficiency.

$$L_{up}^{Eq,DR} = \sum_{DR}^{Flex\ Loads} L_{DR,,t}^{Imp} - L_{DR,t}^{Base} \tag{26}$$

$$L_{dn}^{Eq,DR} = \sum_{DR}^{Flex\ Loads} L_{DR,,t}^{Base} - L_{DR,t}^{Exp} \tag{27}$$

$$C_{Eq,DR} = max\ C_{DR} \tag{28}$$

$$RT_{Eq,DR} = max\ RT_{DR} \tag{29}$$

$$Payback_{Eq,DR} = max\, Payback_{DR} \tag{30}$$

Finally, equations (31)-(35) define the inflexible load, the generation component associated to renewable and non-renewable generation with their respective curtailment and operational cost. The load is determined considering the power exchange at the TSO-DSO interface (this could be at any interface depending on the case study, LV-MV, MV-HV, etc.) minus the power limits of components from the equivalent model that can increase the load, that is the charge of storage and flexible demand and thus, we can capture the inflexible demand. Similarly, for the generation component, we compare their operation from the export and import cases, capturing the power that can be dispatched and curtailed for renewable and non-renewables.

$$Load_t = P_{Imp,t}^{TSO-DSO} - P_{ch,t}^{Eq,BESS} - L_{up}^{Eq,DR} \tag{31}$$

$$Gen_t^{VRE} = Gen_t^{Exp,VRE} - Gen_t^{Imp,VRE} \tag{32}$$

$$Gen_t^{NonVRE} = Gen_t^{Exp,NonVRE} - Gen_t^{Imp,NonVRE} \tag{33}$$

$$C_{NonVRE} = max\, C_{NonVRE} \tag{34}$$

$$C_{Curt}^{VRE} = max\, C_{Curt}^{VRE} \tag{35}$$

Moreover, it is worth mentioning that the intertemporal constraint of the storage component is managed with a state of charge constraint within the integrated planning problem based on these time-varying parameters, thus storage can be optimally managed by the central planner entity.

Appendix C Inclusion of equivalent model and investment cost function to represent distribution system planning within transmission planning

This section presents the mathematical formulation associated to the integrated transmission-distribution planning problem. The focus of this will be on how distribution system planning is included, particularly the parametric investment cost function and associated equivalent model. Also, for simplicity, the index associated to representative periods is included in index *t,* which represents all time-steps.

Table a-7: Description of variables and parameters that represent the planning of active distribution systems within transmission planning

Variable	Description
$\boldsymbol{x_{d,p}}$	**Binary investment decision variable** associated to the distribution system planning scenario *p*, and distribution system *d*
$P_{p,t}^{ch,BESS}, P_{p,t}^{dch,BESS}$	Charging and discharging limit of aggregated storage component associated to distribution planning scenario *p* in time step *t*
$E_{p,max}, E_{p,min}$	Storage limits (MWh) of the aggregated storage component associated to distribution planning scenario *p* in time step *t*
$\boldsymbol{bl_{d,t}, bp_{d,t}, se_{d,t}}$	**Decision variable** for charging, discharging and energy stored of the storage component, for distribution system *d* in time step *t*
$L_{p,t}^{Up,DR}, L_{p,t}^{Dn,DR}$	Power limits for aggregated demand response, upwards and downwards, for distribution planning scenario *p* in time step *t*
$C_{p,DR}, RT_{p,DR}, PB_{p,DR}$	Cost, recovery time, and payback parameter for aggregated demand response services, represented by the equivalent model
$\boldsymbol{pred_{d,t}, pshup_{d,t}, pshdn_{d,t}}$	**Decision variable** for reduction, upward and downward for flexible demand component, for distribution system *d* in time step *t*
$Load_t$	Inflexible load of the equivalent model at time *t*

$Gen_{p,t}^{VRE}, Gen_{p,t}^{NonVRE}$	Generation limits for renewable and non-renewable component of equivalent model for distribution planning scenario *p* in time step *t*
C_t^{NonVRE}, C_t^{Curt}	Operational cost of non-renewable DER and curtailment of renewable DER
$\boldsymbol{p_{d,t}^{VRE}, p_{d,t}^{NonVRE}}$	**Decision variable** for renewable and non-renewable generation component, for distribution system *d* in time step *t*
$\boldsymbol{pcc_{d,t}^{TSO-DSO}}$	**Decision variable** for the power exchanged between the transmission node where the distribution system *d* is connected, for each time step *t*

Thus, the first constraint is associated to the investment decision. As seen in equation (36), only one investment path, out of the parametric investment cost function, must be developed for each distribution system. In this sense, integrated planning would optimally choose the DER adoption (out of all possible levels represented by $p \in P$) that brings the most benefits from a whole system perspective.

$$\sum_{p \in P} x_{d,p} \leq 1 \tag{36}$$

Moreover, the following equations model the operation of the storage component in each time step *t* of each representative period, which are formulated, for each distribution system, as a sum over the parametrisation over DER adoption. Thus, it includes the investment decision variable to only consider the planning scenario, or DER adoption, that is optimal. Equations (37) and (38) limit the charging and discharging power, while (39) does so for the storage. Finally, the state of charge of the aggregated storage component is managed through equation (40), using the parameter μ as efficiency.

$$bl_{d,t} \leq \sum_{p \in P} P_{p,t}^{ch,BESS} x_{d,p} \tag{37}$$

$$bp_{d,t} \leq \sum_{p \in P} P_{p,t}^{dch,BESS} x_{d,p} \tag{38}$$

$$\sum_{p \in P} E_{p,min} x_{d,p} \leq se_{d,t} \leq \sum_{p \in P} E_{p,max} x_{d,p} \tag{39}$$

$$se_{d,t} = se_{d,t-1} + bl_{d,t}\mu - \frac{bp_{d,t}}{\mu} \tag{40}$$

In terms of demand response. The following equations define the time-varying limits of load reduction and shifting services, according to the parameters of the equivalent model. It also includes the investment decision variable to only consider the planning scenario, or DER adoption, that is optimal. Thus, the upward and downward power shifting limits are determined by equations (41) and (42), and in addition, equation (43) models the need to recover the energy from this service, with the corresponding payback PB_d, for all time blocks defined by the recovery time parameter. It must be noted that for simplicity, only the equations associated to load shifting are modelled, however, load reduction is also included in the equivalent model, and the constraint associated to this service is like (42).

$$pshup_{d,t} \leq \sum_{p \in P} L_{p,t}^{Up,DR} x_{d,p} \tag{41}$$

$$pshdn_{d,t} \leq \sum_{p \in P} L_{p,t}^{Dn,DR} x_{d,p} \tag{42}$$

$$\sum_{t \in RT} pshup_{d,t} = PB_d \sum_{t \in RT} pshdn_{d,t} \tag{43}$$

The generation component follows a similar formulation, where the renewable and non-renewable generation is limited as in equations (44) and (45) respectively.

$$p_{d,t}^{VRE} \leq \sum_{p \in P} Gen_{p,t}^{VRE} x_{d,p} \tag{44}$$

$$p_{d,t}^{NonVRE} \leq \sum_{p \in P} Gen_{p,t}^{NonVRE} x_{d,p} \tag{45}$$

Furthermore, equation (46) defines the power exchange between the transmission and distribution (equivalent model) systems, expression that is added to the nodal balance (nodes are represented by index *b*) of the transmission system, as presented in equation (47). Here, we include all the assets connected to the transmission system such as generators and storage, as well as the power flow through transmission lines. Also, we assume that all the demand flexibility is embedded in the variable $pcc_{d \in b,t}^{TSO-DSO}$.

$$\begin{aligned} pcc_{d,t}^{TSO-DSO} = {} & Load_{d,t} + \left(pshup_{d,t} - pshdn_{d,t} - ENS_{d,t}\right) + \left(bl_{d,t} - bp_{d,t}\right) \\ & - p_{d,t}^{VRE} - p_{d,t}^{NonVRE} \end{aligned} \tag{46}$$

$$\begin{aligned} \sum_{s \in STG} \left(bp_{s,b,t} - bl_{s,b,t}\right) + \sum_{g \in GEN} p_{g,b,t} + \sum_{l \in \mathcal{L}_b^{from}} fl_{l,b,t} - \sum_{l \in \mathcal{L}_b^{to}} fl_{l,b,t} \\ = Load_{b,t}^{TSO} - ENS_{b,t} + pcc_{d \in b,t}^{TSO-DSO} \end{aligned} \tag{47}$$

Finally, a transmission planning problem usually minimises the present value of investments and operational costs ($C_n^{INV}(X_{TSO}^{INV}) + C_n^{op}(X_{TSO}^{OP})$) subject to investments and operational constraints such as, unit-commitment, power flow, reserves, and power balance in each node. Thus, to make it an integrated transmission-distribution planning framework, we add to the objective function, the investment and operational component of each distribution system through the parametric investment cost function and the previous constraints associated to the equivalent model ($\sum_{\boldsymbol{d \in DS}} \boldsymbol{C_{d,p}^{INV} x_{d,p}} + \boldsymbol{C_{d,p}^{op}(x_{d,p})}$), where the operational costs are scaled up to represent the whole year, according to the representative periods selected, with the parameter N.

$$\min \ \frac{1}{(1+r)^{V_n}}\left(C_n^{INV}(X_{TSO}^{INV}) + C_n^{op}(X_{TSO}^{OP}) + \sum_{\boldsymbol{d \in DS}} \boldsymbol{C_{d,p}^{INV} x_{d,p}} + \boldsymbol{C_{d,p}^{op}(x_{d,p})}\right) \tag{48}$$

$$\begin{aligned} \boldsymbol{C_{d,p}^{op}}(\boldsymbol{x_{d,p}}) = \ & N\left(\sum_{t \in T} C_t^{NonVRE} p_{d,t}^{NonVRE} + \sum_{t \in T} C_t^{Curt}(Gen_{p,t}^{VRE} x_{d,p} - \ p_{d,t}^{VRE})\right. \\ & \left. + \sum_{t \in T} C_t^{DR}\left(pshup_{d,t} + pshdn_{d,t}\right)\right) \end{aligned} \tag{49}$$

Appendix D Candidate transmission investment options for electricity-hydrogen system planning studies

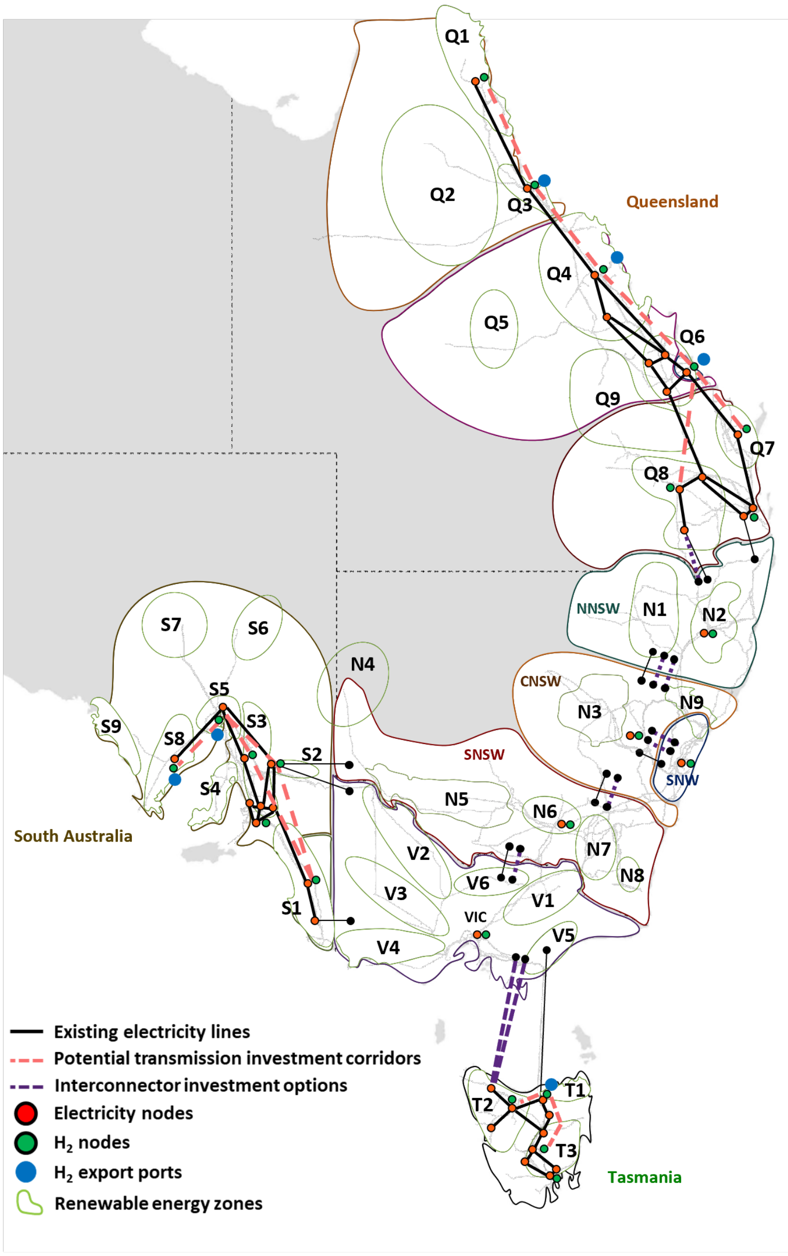

Figure a-2: Geographical illustration of system topology, transmission, REZs, and H_2 export locations.

Table a-8: Electricity transmission lines investment options.

Line	Region A	Region B	Transfer limit (MW)		Investment Cost (M$)
			A to B	B to A	
NNSW–SQ	NNSW	SQ	1260	1700	2,772
CNSW-NNSW Option 1	CNSW	NNSW	3000	3000	1,989
CNSW-NNSW Option 2	CNSW	NNSW	3000	3000	1,625
CNSW-SNW Option 1	CNSW	SNW	5000	0	1,025
CNSW-SNW Option 2	CNSW	SNW	4500	0	1,719
SNSW-CNSW	SNSW	CNSW	2200	2200	5,038
VIC-SNSW	VIC	SNSW	1935	1669	3,908
TAS-VIC Option 1	TAS	VIC	750	750	3,927
TAS-VIC Option 2	TAS	VIC	750	750	2,768
Q1-Q3	Q1	Q3	2000	2000	936
Q3-Q4	Q3	Q4	2000	2000	1,235
Q4-Q6	Q4	Q6	2000	2000	1,377
Q6-Q7	Q6	Q7	2000	2000	936
Q6-Q8	Q6	Q8	2000	2000	1,377
S1-S2	S1	S2	2000	2000	1,149
S1-S3	S1	S3	2000	2000	1,235
S2-S5	S2	S5	2000	2000	936
S3-S5	S3	S5	2000	2000	766
S5-S8	S5	S8	2000	2000	1,021
T1-T2	T1	T1	2000	2000	489
T1-T3	T1	T3	2000	2000	645

Table a-9: Hydrogen pipeline investment options.

Pipeline	Diameter (m)	Length (km)	Investment cost (M$)
Q1-Q3	0.40	245	419
Q3-Q4	0.45	350	612
Q4-Q6	0.45	400	687
Q6-Q7	0.40	245	419
Q6-Q8	0.45	400	687
S1-S2	0.45	320	567
S1-S3	0.45	350	612
S2-S5	0.40	245	419
S3-S5	0.40	185	337
S5-S8	0.40	245	419
T1-T2	0.30	80	164
T1-T3	0.35	130	212

Appendix E Details of REZ investment results

The illustrative geographical location of each REZ can be found in Figure a-2.

Table a-10: Details of investment results under the Step Change scenario under the Normal operation and Resilience case studies.

Investments	Regions	Normal operation studies				Resilience studies			
		Bus level			Hub level	Bus level			Hub level
		Case 1-Base	**Case 2-WithPipe**	**Case 3-Hubs**	**Case 3-Hubs**	**Case 1R-Base**	**Case 2R-WithPipe**	**Case 3R-Hubs**	**Case 3R-Hubs**
BESS (MW)	Q1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q2	47.8	47.8	0.0	163.7	35.9	35.9	0.0	178.8
	Q3	442.7	442.7	70.9	0.0	401.0	401.0	65.3	0.0
	Q4	1049.5	1049.5	140.7	1039.2	862.5	862.5	59.3	741.8
	Q5	5.5	5.5	0.0	25.1	5.1	5.1	0.0	21.8
	Q6	825.0	825.0	0.0	939.8	827.2	827.2	0.0	979.2
	Q7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.0
	N5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V1	0.0	0.0	0.0	1016.5	236.4	236.4	0.0	274.1
	V2	0.0	0.0	0.0	744.3	265.9	265.9	0.0	319.5
	V3	0.0	0.0	0.0	378.7	0.0	0.0	0.0	0.0
	V4	0.0	0.0	0.0	46.6	0.0	0.0	0.0	0.0
	V5	0.0	0.0	0.0	119.3	0.0	0.0	0.0	0.0
	V6	0.0	0.0	0.0	760.8	317.5	317.5	0.0	314.8
	S1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar (MW)	Q1	59.5	59.5	0.0	58.2	59.2	59.2	0.0	60.7
	Q2	29.7	29.7	0.0	247.4	18.7	18.7	0.0	258.8
	Q3	0.0	0.0	0.0	156.7	0.0	0.0	0.0	151.4
	Q4	4064.1	4064.1	0.0	3394.8	3744.3	3744.3	0.0	2935.8

	Q5	5.8	5.8	0.0	84.0	5.1	5.1	0.0	89.0
	Q6	3705.4	3705.4	0.0	3722.3	3556.5	3556.5	0.0	3578.1
	Q7	2200.0	2200.0	0.0	1541.2	2200.0	2200.0	1692.3	0.0
	Q8	1506.4	1506.4	0.0	2690.9	964.7	964.7	0.0	2177.9
	Q9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N1	199.2	199.2	191.3	0.0	248.8	248.8	245.4	0.0
	N2	524.0	524.0	0.0	527.5	781.9	781.9	0.0	770.0
	N3	5638.7	5638.7	0.0	5919.2	6850.0	6850.0	0.0	6850.0
	N4	263.8	263.8	269.5	0.0	321.0	321.0	0.0	336.4
	N5	259.0	259.0	198.0	0.0	332.2	332.2	328.6	0.0
	N6	1192.0	1192.0	1028.0	0.0	1579.5	1579.5	1447.8	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N8	0.0	0.0	0.0	0.0	121.9	121.9	0.0	192.6
	N9	516.0	516.0	0.0	385.3	516.0	516.0	0.0	594.4
	V1	466.2	466.2	0.0	2705.3	978.3	978.3	0.0	999.2
	V2	550.8	550.8	0.0	1679.9	1172.3	1172.3	0.0	1216.8
	V3	0.0	0.0	0.0	400.0	400.0	400.0	0.0	532.2
	V4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V5	500.0	500.0	0.0	2415.5	2473.5	2473.5	0.0	2473.5
	V6	765.3	765.3	0.0	1911.6	1477.4	1477.4	0.0	1409.1
	S1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.9
	S4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S5	524.3	524.3	0.0	12.7	1470.3	1470.3	0.0	997.0
	S6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S7	0.0	0.0	0.0	0.0	599.4	599.4	615.1	0.
	S8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T1	0.0	0.0	0.0	300.0	0.0	0.0	0.0	96.3
	T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind (MW)	Q1	633.3	633.3	0.0	613.1	616.1	616.1	0.0	586.4
	Q2	1245.1	1245.1	0.0	1160.5	1222.2	1222.2	0.0	1152.6
	Q3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q4	0.0	0.0	0.0	204.7	529.8	529.8	0.0	744.2
	Q5	123.5	123.5	0.0	116.9	123.6	123.6	0.0	110.3
	Q6	1718.6	1718.6	0.0	2162.0	1703.7	1703.7	0.0	2381.9
	Q7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q8	5600.0	5600.0	0.0	4895.5	5233.6	5233.6	0.0	4778.2
	Q9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N2	340.5	340.5	0.0	360.8	395.7	395.7	0.0	397.9
	N3	2726.5	2726.5	0.0	1073.9	3864.3	3864.3	0.0	4171.5
	N4	159.3	159.3	0.0	0.0	254.7	254.7	0.0	279.0
	N5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N8	405.3	405.3	402.4	0.0	402.4	402.4	0.0	399.0
	N9	1524.4	1524.4	0.0	1400.0	1524.4	1524.4	0.0	1524.4
	V1	0.0	0.0	0.0	942.1	0.0	0.0	0.0	0.0
	V2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V3	2165.9	2165.9	0.0	2448.1	1813.7	1813.7	0.0	1761.7
	V4	2249.4	2249.4	0.0	2349.0	2135.7	2135.7	2032.8	0.0
	V5	1030.6	1030.6	0.0	1030.6	1030.6	1030.6	0.0	1030.6
	V6	382.9	382.9	0.0	620.3	843.3	843.3	0.0	880.8

	S1	0.0	0.0	0.0	6.6	0.0	0.0	0.0	0.0
	S2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S3	2420.7	2420.7	0.0	1667.8	3815.7	3815.7	0.0	2938.2
	S4	122.5	122.5	0.0	0.0	0.0	0.0	0.0	0.0
	S5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S8	1100.2	1100.2	0.0	1062.8	0.0	0.0	0.0	621.0
	S9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T1	0.0	0.0	0.0	189.4	239.5	239.5	0.0	181.9
	T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T3	2318.3	2318.3	723.5	1355.1	2318.3	2318.3	297.7	2020.6
Electrolyser (MW)	Q1	61.5	61.5	0.0	66.7	58.4	58.4	0.0	69.5
	Q3	458.4	458.4	0.0	132.3	483.5	483.5	0.0	127.1
	Q4	591.5	591.5	0.0	969.6	555.4	555.4	0.0	915.8
	Q6	554.3	554.3	0.0	581.7	533.6	533.6	0.0	634.0
	Q7	54.7	54.7	0.0	69.4	53.1	53.1	0.0	67.0
	Q8	405.4	405.4	0.0	421.5	401.7	401.7	0.0	403.1
	S1	4.0	4.0	0.0	2.9	5.3	5.3	4.0	0.0
	S3	323.5	323.5	0.0	276.4	399.4	399.4	0.0	466.9
	S5	8.7	8.7	0.0	5.5	251.6	251.6	0.0	268.5
	S8	372.5	372.5	0.0	292.7	246.4	246.4	0.0	205.4
	T1	261.2	261.2	60.4	264.8	300.1	300.1	155.7	146.6
	T2	33.1	33.1	28.4	0.0	40.1	40.1	28.4	0.0
	T3	99.1	99.1	0.0	164.6	126.4	126.4	0.0	173.2
	Brisbane	919.9	919.9	909.0	-	915.0	915.0	904.6	-
	NNSW	70.9	70.9	80.2	-	76.1	76.1	76.1	-
	CNSW	149.4	149.4	143.1	-	177.3	177.3	166.0	-
	SNW	952.6	952.6	930.4	-	1099.5	1099.5	1058.8	-
	SNSW	156.9	156.9	133.2	-	155.4	155.4	160.3	-
	VIC	1659.0	1659.0	1526.3	-	2041.2	2041.2	1934.2	-

	Junction	Case 1-Base	Case 2-WithPipe	Case 3-Hubs	Case 1R-Base	Case 2R-WithPipe	Case 3R-Hubs
H_2 storage (GWh)	Q1	0.3	0.3	0.4	0.5	0.5	0.2
	Q3	5.4	5.4	0.8	5.5	5.5	1.2
	Q4	5.4	5.4	7.4	5.5	5.5	7.1
	Q6	5.4	5.4	4.7	5.5	5.5	4.7
	Q7	0.6	0.6	0.4	0.6	0.6	0.4
	Q8	4.0	4.0	3.8	4.2	4.2	4.0
	S1	0.0	0.0	0.0	0.1	0.1	0.1
	S3	3.4	3.4	2.3	5.9	5.9	6.4
	S5	0.0	0.0	0.0	3.8	3.8	3.4
	S8	4.4	4.4	3.2	3.7	3.7	2.2
	T1	0.1	0.1	2.3	1.7	1.7	1.6
	T2	0.1	0.1	0.0	0.5	0.5	0.0
	T3	0.2	0.2	3.2	1.4	1.4	2.9
	Brisbane	8.9	8.9	9.2	8.9	8.9	8.8
	NNSW	1.8	1.8	0.9	1.5	1.5	1.5
	CNSW	0.6	0.6	0.4	1.4	1.4	1.2
	SNW	3.4	3.4	2.4	8.3	8.3	7.7
	SNSW	2.3	2.3	0.1	1.8	1.8	1.1
	VIC	23.5	23.5	42.4	34.1	34.1	32.4

REZ network expansion (MW)	REZs	Case 1-Base	Case 2-WithPipe	Case 3-Hubs	Case 1R-Base	Case 2R-WithPipe	Case 3R-Hubs
	Q2	0.0	0.0	0.0	0.0	0.0	0.0
	Q5	0.0	0.0	0.0	0.0	0.0	0.0

	Q9	0.0	0.0	0.0	0.0	0.0	0.0
	N1	0.0	0.0	0.0	0.0	0.0	0.0
	N2	0.0	0.0	0.0	0.0	0.0	0.0
	N3	0.0	0.0	0.0	256.1	256.1	0.0
	N4	0.0	0.0	0.0	0.0	0.0	0.0
	N5	0.0	0.0	0.0	0.0	0.0	0.0
	N6	0.0	0.0	0.0	0.0	0.0	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0
	N8	0.0	0.0	0.0	0.0	0.0	0.0
	N9	908.7	908.7	798.1	904.4	904.4	902.1
	V1	0.0	0.0	544.9	0.0	0.0	0.0
	V2	0.0	0.0	0.0	0.0	0.0	0.0
	V3	249.7	249.7	381.4	0.0	0.0	0.0
	V4	0.0	0.0	0.0	0.0	0.0	0.0
	V5	0.0	0.0	0.0	0.0	0.0	0.0
	V6	0.0	0.0	0.0	0.0	0.0	0.0
	S2	0.0	0.0	0.0	0.0	0.0	0.0
	S4	0.0	0.0	0.0	0.0	0.0	0.0
	S6	0.0	0.0	0.0	0.0	0.0	0.0
	S7	0.0	0.0	0.0	0.0	0.0	0.0
	S9	0.0	0.0	0.0	0.0	0.0	0.0

Table a-11: Details of investment results under the Green Energy Exports scenario under the Normal operation and Resilience case studies.

Investments	Regions	Normal operation studies				Resilience studies			
		Bus level			**Hub level**	**Bus level**			**Hub level**
		Case 1-Base	**Case 2-WithPipe**	**Case 3-Hubs**	**Case 3-Hubs**	**Case 1R-Base**	**Case 2R-WithPipe**	**Case 3R-Hubs**	**Case 3R-Hubs**
	Q1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q2	92.6	92.4	0.0	146.7	263.3	150.1	0.0	173.3
	Q3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q4	977.1	1011.0	0.0	824.2	818.3	1165.9	0.0	743.4
	Q5	9.0	31.1	0.0	43.1	22.6	61.2	0.0	62.9
	Q6	242.7	289.5	0.0	425.9	0.3	0.0	0.0	410.6
	Q7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q9	133.0	150.0	0.0	151.5	107.7	133.8	0.0	151.5
	N1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N2	0.0	0.0	0.0	0.0	49.2	51.6	0.0	73.0
BESS (MW)	N3	0.0	0.0	0.0	0.0	788.9	651.6	0.0	1714.0
	N4	0.0	0.0	0.0	0.0	23.1	23.7	0.0	212.7
	N5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N8	0.0	0.0	0.0	0.0	0.3	1.3	0.0	5.6
	N9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V1	375.2	365.3	0.0	394.5	253.5	258.9	0.0	261.8
	V2	244.0	213.9	0.0	133.7	1526.5	1582.7	0.0	757.4
	V3	13.4	3.3	0.0	5.7	0.0	0.0	0.0	0.0
	V4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V6	870.5	936.7	0.0	1169.1	0.3	0.0	0.0	1246.6

	S1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S2	0.0	0.0	0.0	0.0	6.6	4.8	0.0	90.4
	S3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S4	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	S5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S6	0.0	0.0	0.0	0.0	523.1	546.5	0.0	641.4
	S7	0.0	0.0	0.0	0.0	442.6	432.3	0.0	533.4
	S8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar (MW)	Q1	0.0	1100.0	0.0	1335.9	0.0	1100.0	0.0	1100.0
	Q2	1299.9	728.0	0.0	804.2	1644.4	779.7	0.0	827.2
	Q3	3400.0	3400.0	0.0	3400.0	3400.0	3400.0	0.0	3400.0
	Q4	14775.8	11748.6	0.0	11048.8	11209.7	9653.5	0.0	9471.7
	Q5	92.2	116.4	0.0	136.4	110.6	160.9	0.0	158.7
	Q6	7533.0	7533.0	0.0	7533.0	7533.0	7533.0	0.0	7533.0
	Q7	2485.5	2517.2	0.0	2200.0	2200.0	2200.0	0.0	2200.0
	Q8	5491.5	5696.4	0.0	5826.0	4504.1	4556.2	0.0	4912.5
	Q9	363.8	362.9	0.0	350.5	321.4	348.5	0.0	350.1
	N1	216.1	226.4	223.5	0.0	255.7	256.1	253.5	0.0
	N2	639.0	630.0	0.0	645.3	816.5	825.9	0.0	845.4
	N3	1241.2	1257.5	0.0	1149.6	6850.0	6850.0	0.0	6850.0
	N4	337.8	323.4	338.1	0.0	403.5	401.6	0.0	646.4
	N5	270.0	268.4	270.3	0.0	350.4	350.5	348.1	0.0
	N6	1390.7	1384.0	1390.9	0.0	1678.8	1678.1	1664.5	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N8	0.0	0.0	0.0	312.1	313.4	155.9	0.0	176.1
	N9	6167.3	6359.8	0.0	6145.6	4595.9	4973.9	0.0	6379.7
	V1	1000.0	1000.0	0.0	1000.0	1000.0	1000.0	0.0	1000.0
	V2	999.6	952.5	0.0	834.5	4219.8	4375.1	0.0	1996.9
	V3	0.0	0.0	0.0	0.0	400.0	400.0	0.0	400.0
	V4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V5	5817.6	5829.8	0.0	7192.1	5920.4	5825.1	0.0	7312.6
	V6	5150.1	5217.6	0.0	4014.1	12163.9	11136.6	0.0	11007.6
	S1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6
	S2	178.2	178.2	0.0	0.0	216.8	214.0	0.0	338.8
	S3	1020.7	1076.6	0.0	1300.0	1300.0	1300.0	0.0	1300.0
	S4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S5	2900.0	2900.0	0.0	3585.0	10297.7	10197.1	0.0	13270.5
	S6	0.0	0.0	0.0	0.0	3332.7	3343.9	0.0	1990.1
	S7	649.8	649.8	0.0	0.0	1381.0	1362.3	0.0	1483.8
	S8	4886.0	4878.4	0.0	5000.0	0.0	0.0	0.0	43.6
	S9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T1	758.1	2420.9	0.0	2122.6	300.0	0.0	0.0	300.0
	T2	0.0	150.0	0.0	4.5	0.0	0.0	0.0	150.0
	T3	0.0	150.0	0.0	150.0	0.0	0.0	0.0	0.0
Wind (MW)	Q1	4174.8	7402.4	0.0	7389.9	4169.0	7358.3	0.0	7174.5
	Q2	3282.5	1052.2	0.0	1004.0	3692.4	1046.2	0.0	1005.3
	Q3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q5	132.2	102.9	0.0	91.5	111.7	41.4	0.0	39.6
	Q6	1036.3	1253.4	0.0	1379.2	3500.0	2353.8	0.0	2386.1
	Q7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Q8	5215.6	5600.0	0.0	5600.0	3919.4	4780.3	0.0	4646.8

	Q9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N2	369.9	573.6	0.0	637.5	685.7	666.5	0.0	658.1
	N3	115.4	28.2	0.0	614.0	3000.0	3000.0	0.0	3000.0
	N4	0.0	0.0	0.0	0.0	0.3	27.0	0.0	164.4
	N5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	N8	3145.1	2944.8	0.0	2513.5	1079.8	915.7	0.0	402.0
	N9	7622.0	7622.0	0.0	7622.0	7622.0	7622.0	0.0	7622.0
	V1	390.8	345.1	0.0	452.2	0.0	0.0	0.0	0.0
	V2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	V3	2600.0	2600.0	0.0	2161.2	1846.0	1861.7	0.0	1812.7
	V4	3443.0	3443.0	3443.0	0.0	1779.9	2126.2	1584.3	0.0
	V5	5142.3	5072.8	0.0	4990.1	5153.0	5153.0	0.0	5153.0
	V6	1600.0	1600.0	0.0	2438.7	3619.0	3100.1	0.0	4736.3
	S1	1199.4	1194.5	0.0	1070.5	0.0	0.0	0.0	8.5
	S2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S3	4600.0	4600.0	0.0	4568.9	4931.2	5050.2	0.0	4600.0
	S4	125.1	125.4	0.0	122.9	0.0	0.0	0.0	0.0
	S5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S6	0.0	0.0	0.0	0.0	2400.0	2400.0	0.0	1115.1
	S7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	S8	5543.2	5533.1	0.0	5287.4	1667.5	1703.7	0.0	1486.1
	S9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	T1	7024.4	1548.0	0.0	4168.8	7942.7	1400.0	0.0	1400.0
	T2	3008.0	2101.2	0.0	22.6	3735.9	2772.6	0.0	2780.9
	T3	4165.7	8402.6	0.0	7948.3	6306.3	11400.1	0.0	10943.3
Electrolyser (MW)	Q1	99.5	2575.0	0.0	2671.0	101.8	2538.4	0.0	2518.0
	Q3	4102.5	2321.2	0.0	2428.8	4393.0	2454.8	0.0	2357.5
	Q4	8357.3	6558.0	0.0	6606.2	6436.7	5041.8	0.0	5546.2
	Q6	2336.3	2417.5	0.0	2371.7	2909.5	3005.5	0.0	3107.8
	Q7	88.2	81.4	0.0	86.0	70.1	79.7	0.0	87.6
	Q8	560.8	712.0	0.0	711.6	492.2	631.9	0.0	623.4
	S1	10.5	9.6	0.0	11.3	9.8	10.4	0.0	7.5
	S3	746.3	752.4	0.0	820.1	683.4	728.3	0.0	773.1
	S5	2449.0	2481.1	0.0	2296.8	6932.6	6942.0	0.0	8054.9
	S8	3986.2	3979.3	0.0	4611.5	601.3	601.5	0.0	604.2
	T1	7951.7	2477.8	70.5	3886.9	7880.2	1385.2	236.3	938.2
	T2	28.4	1574.9	0.0	13.4	48.6	1978.6	165.0	2008.4
	T3	53.6	3440.3	0.0	3580.7	115.9	4785.6	0.0	5340.2
	Brisbane	1292.5	1242.3	1157.3	-	1058.1	1117.9	1056.5	-
	NNSW	220.9	199.8	183.4	-	187.9	229.0	182.6	-
	CNSW	514.3	498.2	468.6	-	492.4	471.6	455.6	-
	SNW	1925.6	2045.4	1997.1	-	2498.0	2582.7	2426.1	-
	SNSW	233.2	234.6	283.3	-	447.5	450.1	423.1	-
	VIC	3382.1	3360.9	3353.0	-	5191.0	5095.8	4634.0	-

	Junction	Case 1-Base	Case 2-WithPipe	Case 3-Hubs	Case 1R-Base	Case 2R-WithPipe	Case 3R-Hubs
H_2 storage (GWh)	Q1	1.8	27.4	34.5	1.8	23.7	19.6
	Q3	4.2	0.0	0.0	7.7	0.0	0.0
	Q4	20.7	0.0	0.2	5.4	7.1	3.5
	Q6	23.7	18.0	17.3	25.9	5.9	18.3
	Q7	0.0	0.1	0.2	0.0	0.2	0.1
	Q8	4.6	3.4	4.5	4.6	4.6	4.6
	S1	0.2	0.2	0.2	0.1	0.1	0.1

	S3	11.7	11.8	10.9	4.5	5.2	7.0
	S5	18.9	18.4	8.4	30.9	31.9	15.1
	S8	49.5	49.4	57.8	6.6	6.3	7.6
	T1	187.3	14.7	84.5	172.8	16.4	40.9
	T2	0.8	49.6	0.3	0.8	50.7	24.4
	T3	1.2	111.5	108.8	1.8	102.9	102.6
	Brisbane	8.4	7.8	6.5	11.1	11.1	11.1
	NNSW	4.0	2.7	3.1	2.8	3.4	2.6
	CNSW	4.4	4.2	3.7	4.2	3.8	5.0
	SNW	18.7	18.0	19.8	17.6	16.3	17.3
	SNSW	1.9	2.3	1.9	5.4	3.6	5.8
	VIC	107.1	105.9	105.3	82.9	82.1	70.2
REZ network expansion (MW)	REZs	**Case 1-Base**	**Case 2-WithPipe**	**Case 3-Hubs**	**Case 1R-Base**	**Case 2R-WithPipe**	**Case 3R-Hubs**
	Q2	1186.3	0.0	0.0	1476.5	0.0	0.0
	Q5	0.0	0.0	0.0	0.0	0.0	0.0
	Q9	0.0	0.0	0.0	0.0	0.0	0.0
	N1	0.0	0.0	0.0	0.0	0.0	0.0
	N2	0.0	0.0	0.0	0.0	0.0	0.0
	N3	0.0	0.0	0.0	3044.8	3167.4	2226.1
	N4	0.0	0.0	0.0	0.0	0.0	0.0
	N5	0.0	0.0	0.0	0.0	0.0	0.0
	N6	0.0	0.0	0.0	0.0	0.0	0.0
	N7	0.0	0.0	0.0	0.0	0.0	0.0
	N8	2327.1	2149.3	1808.4	575.6	434.2	0.0
	N9	9133.1	9261.5	7921.0	7198.9	7496.3	7649.5
	V1	71.3	69.9	82.5	1.4	0.0	0.0
	V2	0.0	0.0	0.0	473.5	507.2	0.0
	V3	503.1	494.6	186.9	0.0	0.0	0.0
	V4	990.1	961.4	993.1	0.0	0.0	0.0
	V5	0.0	0.0	0.0	0.0	0.0	0.0
	V6	2639.6	2625.5	1603.4	7031.1	6492.1	5497.6
	S2	0.0	0.0	0.0	0.0	0.0	0.0
	S4	0.0	0.0	0.0	0.0	0.0	0.0
	S6	0.0	0.0	0.0	2130.3	2135.6	921.9
	S7	0.0	0.0	0.0	0.0	0.0	0.0
	S9	0.0	0.0	0.0	0.0	0.0	0.0

Appendix F Publications

These are the publications related to this project:

- R. Chen, S. Mhanna, P. Mancarella. *Optimal Design of Electrolysis-based Hydrogen Hubs: Impact of Different Hydrogen Demand Profile Assumptions on System Flexibility and Investment Portfolios*. *Accepted Paper - Sustainable Energy, Grids and Networks (SEGAN).*
- P. Apablaza, S. Püschel-Løvengreen, R. Moreno, P. Mancarella. *Valuing Distributed Energy Resources Flexibility in a Risk-Aware and Uncertain Power System Planning Context. Accepted Paper - Sustainable Energy, Grids and Networks (SEGAN).*