

Portfolio of contingent projects

2024–29 revenue proposal

Record Number: R2114846

Version Number: 1.0

Date: November 2022

Executive summary

This report provides the justification for the inclusion of a portfolio of contingent projects in TasNetworks' transmission revenue proposal submission for the upcoming 2024–29 regulatory control period. The identified contingent projects reflect the scale of possible transmission network augmentations required to support upcoming major developments in the network. It is not proposed to include contingent projects in our distribution regulatory proposal.

The following contingent projects are proposed for the 2024–29 regulatory control period:

Id	Identified Need	Indicative Solution
1	Address network security requirements at George Town Substation	George Town Substation network reinforcement
2	Maintain voltage stability at George Town Substation (to 2026)	George Town Reactive Support (Stage 1)
3	Maintain voltage stability at George Town Substation (to 2029)	George Town Reactive Support (Stage 2)
4	Address power transfer capability to George Town (Stage 1)	Palmerston to Sheffield Network Upgrade
5	Address power transfer capability to George Town (Stage 2)	Sheffield to George Town Network Upgrade
6	Address power transfer capability to George Town (Stage 3)	Palmerston to George Town via Hadsphen Network Upgrade
7	Address transfer capability constraints on the Waddamana–Palmerston 220 kV corridor	Waddamana to Palmerston transfer capability upgrade

Contingent projects are network investments that may be required during the 2024–29 regulatory control period. They are treated differently to other regulated investments due to their dependence on specific trigger events that carry a level of uncertainty. If the initiating criteria to trigger the project occur, and if the Australian Energy Regulator is satisfied that the forecast expenditure is prudent and efficient, it will amend TasNetworks' revenue determination under NER clause 6A.8.2(e)(3) for the remainder of the relevant regulatory control period.

Contents

1	Background	4
2	Rules requirements	5
2.1	Criteria for inclusion	5
2.2	Trigger events	5
2.3	Activation of transmission contingent projects	6
3	Drivers	6
3.1	Tasmanian Renewable Energy Target	7
3.2	Green hydrogen production	8
4	Identified contingent projects	9
4.1	Project 1: Address network security requirements at George Town Substation	12
4.2	Maintain voltage stability at George Town Substation	15
4.3	Address power transfer capability to George Town	18
4.4	Project 7: Waddamana–Palmerston transfer capability upgrade	23
4.5	Demonstration of Rules compliance	27
5	Other contingent projects	27
5.1	Network development for system strength rule change	29
5.2	North West Transmission Development	30
6	Distribution network contingent projects	30
7	Appendix A: Geographic Overview of contingent project augmentations	31

1 Background

Contingent projects are projects where:

- the need, timing or cost of significant network augmentation is uncertain but probable;
- the requirement to invest is dependent on something occurring in the future, usually a set of events or circumstances (triggers) that are largely beyond TasNetworks' control; and
- the proposed contingent capital expenditure exceeds the greater of \$30 million or 5% of the value of the allowed revenue.

Costs associated with contingent projects are excluded from the regulated capital expenditure (capex) allowances at the beginning of the five-year regulatory control period due to uncertainty in their need and timing.

There are generally two possible avenues for a contingent project:

- acceptance as a contingent project under a revenue determination with subsequent amendment to the determination; and
- an actionable integrated system plan (ISP) project.

Under the National Electricity Rules (NER), a contingent project is a project assessed by the Australian Energy Regulator (AER) as reasonably required to be undertaken within the relevant regulatory control period, but which is excluded from the capex allowance in a transmission or distribution determination because of a relatively high degree of uncertainty about its timing or costs. For non-actionable ISP projects, the Network Service Provider (NSP) must identify each contingent project, its indicative costing and proposed trigger event(s) in the regulatory proposal.

No contingent projects have been identified in relation to our distribution network for the 2024–29 regulatory control period.

In order to satisfy the AER's requirements sufficient details must be provided to inform an assessment of:

- whether the project meets the contingent project criteria;
- the likelihood of the project commencing during the regulatory control period in question;
- the need for the project;
- whether the proposed trigger events are appropriate, reasonably specific and capable of objective verification; and
- whether the trigger events are consistent with the identified need for the project.

The level of detail provided for each assessment criteria will be informed by the information available at the time of writing. Contingent projects with minimal available information are described in terms of the most likely network development required to satisfy the trigger events for the project. With information limited to the project drivers (including supporting documentation), trigger events and indicative costs.

2 Rules requirements

NER Clause 6A.8 (for transmission networks) and clause 6.6A (for distribution networks) provide that contingent projects may be included in an NSP's proposal.

2.1 Criteria for inclusion

Under NER clause 6A.8.1(b), for a proposed contingent project to be accepted by the AER in TasNetworks' 2024–29 revenue determination it must satisfy the following criteria:

- be reasonably required to be undertaken in order to achieve any of the capital expenditure objectives in the NER;
- not otherwise be provided for in TasNetworks' total forecast capex for the 2024–29 regulatory control period;
- reasonably reflect the capex criteria, when considering the capex factors in the NER;
- exceed either \$30 million or 5% of TasNetworks' maximum allowable revenue for the first year of the 2024–29 regulatory control period, whichever is larger; and
- have appropriate trigger events.

2.2 Trigger events

As part of the revenue proposal specific events must be proposed that will trigger a requirement to undertake each contingent project. Under NER clause 6A.8.1(c), in determining whether a trigger event in relation to a proposed contingent project is appropriate, the AER must have regard to the need for the event:

- to be reasonably specific and capable of objective verification;
- to be a condition or event which, if it occurs, makes the investment in the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives in the NER;
- to be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission or distribution network as a whole;
- to be described in such terms that it is all that is required for the revenue determination to be amended; and
- to be a condition or event, the occurrence of which is probable during the relevant regulatory control period but the inclusion of capex in relation to it is not appropriate because either:
 - it is not sufficiently certain that the event or condition will occur during the period, or if it may occur after that period or not at all; or
 - assuming it meets the materiality threshold, the costs associated with the event or condition are not sufficiently certain.

2.3 Activation of transmission contingent projects

Under NER clause 6A.8.2(a), if the trigger for a specific contingent project occurs during the regulatory control period, a Contingent Project Application (CPA) may be submitted to the AER to re-open the transmission determination and amend the annual revenue requirements. An application to the AER must include certain details regarding the contingent project, including the forecast capex and project commencement and completion dates. The capex forecast in the CPA may differ from that included in the revenue determination.

In line with the AER's expectations, TasNetworks will engage with our customers and customer advocates on any CPA scope and costs. Affected stakeholders will be given an opportunity to ask questions and engage directly on the project. Stakeholders will also have the opportunity to discuss these projects during the Regulatory Investment Test for Transmission process, which will be completed prior to the CPA process. TasNetworks will also engage with the AER on CPA planning and preparation.

If the AER is satisfied that the trigger events have occurred and the forecast expenditure is prudent and efficient, it will amend the revenue determination under NER clause 6A.8.2(e)(3) for the remainder of the relevant regulatory control period. If the AER is not satisfied, it can reduce the forecast in the CPA.

3 Drivers

The proposed contingent projects can all be linked back to the following drivers that are foreseen as part of the future operating environment:

- Tasmanian Renewable Energy developments; and
- Renewable hydrogen.

Transmission augmentations associated with Marinus Link have been identified by AEMO as Actionable Integrated System Plan projects and are considered separately. Future hydrogen developments are not expected to change the network augmentation requirements for the establishment of Marinus Link.

Also, any projects required arising from responsibilities as a System Strength Service Provider are considered separately.

3.1 Tasmanian Renewable Energy Target

Tasmania is already Australia's largest producer of renewable electricity, with 3,000 MW of installed renewable energy generation. Under the Tasmanian Renewable Energy Target (TRET), the State's renewable energy output is expected to double, so that by 2040 Tasmania will be producing twice as much clean energy as it does now. Delivering the legislated TRET will see Tasmania's current baseline of 10,500 GWh per annum of renewable energy generation increase to 21,000 GWh by 2040. An interim target of lifting renewable generation in Tasmania to 150 per cent of 2022 levels by 2030 will see the output from renewable generation reach 15,750 GWh.

The Renewable Energy Coordination Framework (RECF) sets out the Tasmanian Government's plans to ensure that the renewable energy projects needed to achieve the TRET, including development of Tasmania's Renewable Energy Zones (REZs). The following diagram illustrates the location of each REZ in Tasmania. It is anticipated that the three REZs and the offshore wind zone (OWZ) in north-west Tasmania will be the locations for most of the new generation required to achieve the State Government's renewable energy targets, as well as hydrogen production facilities.

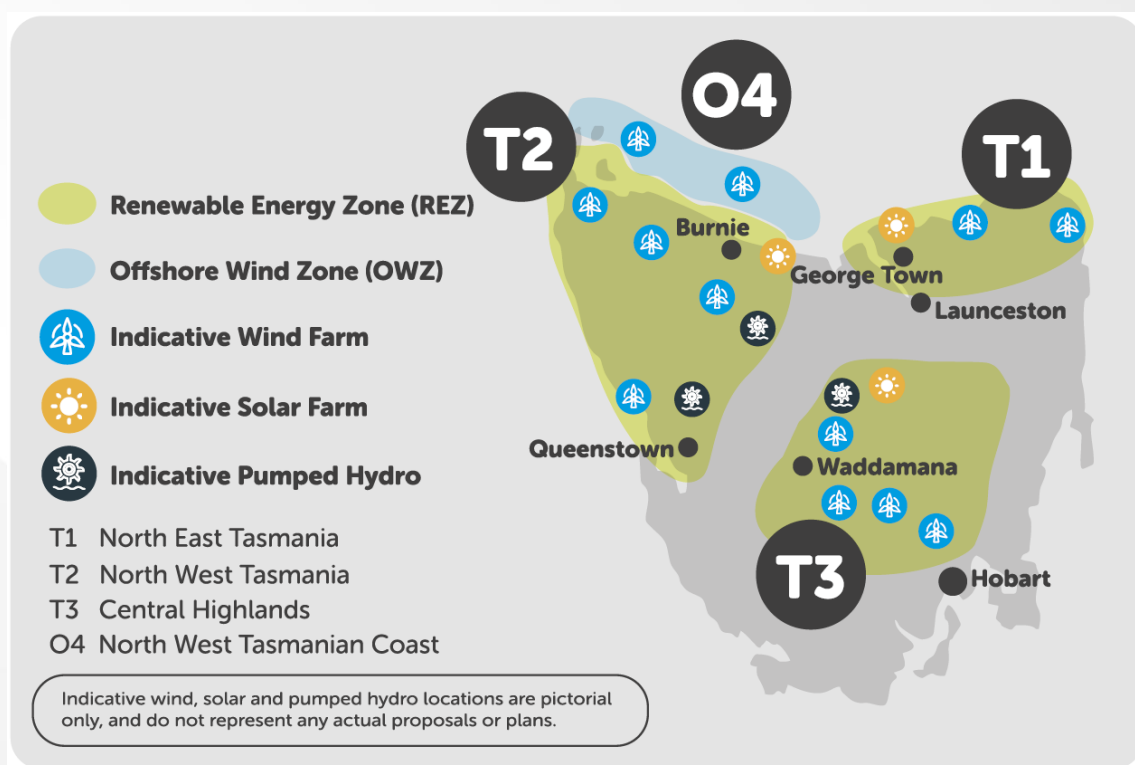


Figure 1: Tasmania's Renewable Energy Zones

TasNetworks' 2022 Annual Planning Report (APR) provides a detailed analysis of the implications for network capacity of a range of scenarios covering the potential location of new generation and load across the REZs in Tasmania – and the implications for the cost of the network.

3.2 Green hydrogen production

The Tasmanian Renewable Hydrogen Action Plan¹ sets out a vision for Tasmania to capitalise on its existing and expandable renewable energy resources to become a world-leader in large-scale renewable green hydrogen production for domestic use and export.

The Tasmanian Renewable Hydrogen Action Plan contains the following goals:

- By 2024, the production of renewable hydrogen will have commenced in Tasmania, with locally produced renewable hydrogen being used in Tasmania and projects to produce renewable hydrogen for export well advanced.
- By 2025 to 2027, Tasmania will have begun exporting renewable hydrogen.
- From 2030, locally produced renewable hydrogen is a significant form of energy used in Tasmania and the State will be a significant global producer and exporter of renewable hydrogen.

Both the *National Hydrogen Strategy* and the *Tasmanian Renewable Hydrogen Action Plan* recognise the importance of developing hydrogen production hubs to leverage existing infrastructure and develop the industry. Tasmania has a number of sites that are well suited to large-scale hydrogen production, including the Bell Bay Advanced Manufacturing Zone (**BBAMZ**) near George Town.

The location, scale and timing of hydrogen production developments are some of the key drivers of the need for transmission network augmentation in Tasmania.

The BBAMZ has been identified as the site for a potential hydrogen hub due to its access to:

- certifiable renewable energy;
- high-quality fresh water; and
- significant vacant industrial land in close proximity to deep-water port facilities.

TasNetworks has received connection enquiries and pre-enquiries for hydrogen connections over 2,500 MW in the George Town area. According to the time-line indicated in these enquiries and pre-enquiries, over 1,000 MW hydrogen may be connected by 2026, and progressively the rest of the hydrogen loads may be connected by 2029.

There is capacity at George Town Substation to support up to a 100 to 150 MW hydrogen production facility from the existing shared transmission network, with appropriate dynamic reactive support that addresses network security issues and the load participating in the System Protection Scheme (**SPS**).

¹ [Tasmanian Renewable Hydrogen Action Plan web 27 March 2020.pdf \(recfit.tas.gov.au\)](https://recfit.tas.gov.au)

4 Identified contingent projects

In response to the identified needs and emerging future constraints, the following contingent projects are included for the 2024–29 regulatory proposal submission.

Table 1: Identified contingent projects

Id	Project description and Identified Need	Driver	Triggers	Indicative cost (\$m)
1	George Town Substation Network Reinforcement : Address network security requirements at George Town Substation	New load at or around George Town / Bell Bay	<ol style="list-style-type: none"> 1. TasNetworks demonstrates that customer commitment of additional load to connect to the transmission network in the George Town-Bell Bay area results in: <ul style="list-style-type: none"> • a material increase in the probability of cascading failure, following non-credible contingent events, as defined in clause S5.1.8 of the NER; and, or, • breaches of minimum network performance requirements under regulation 5 of the <i>Electricity Supply Industry (Network Planning Requirements) Regulations</i> 2. TasNetworks demonstrates that the solution required to meet the power system security obligations cannot be accommodated within the existing layout of George Town substation 3. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates a network investment is the most efficient option to ensure TasNetworks meets its power system security obligations at George Town under: <ul style="list-style-type: none"> o clause S5.1.8 of the NER; o The <i>Electricity Supply Industry (Network Planning Requirements) Regulations</i>; 4. TasNetworks' Board commitment to proceed with the project subject to the Australian Energy Regulator amending the revenue determination pursuant to the NER. 	50
2	George Town Area Reactive Support (Stage 1) : Maintain voltage stability at George Town Substation (to 2026)	New load at or around George Town / Bell Bay	<ol style="list-style-type: none"> 1. TasNetworks demonstrates customer commitment of additional load to connect to the transmission network in the George Town-Bell Bay area will result in TasNetworks being non-compliant with power system voltage and system stability requirements at George Town with respect to clause S5.1.8 of the NER. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, demonstrating a network investment is the most efficient option to meet reactive support requirements at George Town under Clause S5.1.8 of the NER; and 3. TasNetworks' Board commitment to proceed with the project subject to the Australian Energy Regulator amending the revenue determination pursuant to the NER. 	75

3	George Town Area Reactive Support (Stage 2) : Maintain voltage stability at George Town Substation (to 2029)	New load at or around George Town / Bell Bay	<ol style="list-style-type: none"> 1. TasNetworks demonstrates that a second occurrence of load committed to connect to the transmission network in the George Town-Bell Bay area will result in TasNetworks being non-compliant with power system voltage and system stability requirements at George Town with respect to clause S5.1.8 of the NER; 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, demonstrating a network investment is the most efficient option to meet reactive support requirements at George Town under Clause S5.1.8 of the NER; and 3. TasNetworks' Board commitment to proceed with the project subject to the Australian Energy Regulator amending the revenue determination pursuant to the NER. 	80
4	Address power transfer capability to George Town (Stage 1) Palmerston to Sheffield Network Upgrade	New load at or around George Town / Bell Bay and / or New generation in North West or Central Highlands	<ol style="list-style-type: none"> 1. One or both of the following: <ol style="list-style-type: none"> a. Commitment of additional load from one or more customers to connect to the transmission network in the George Town-Bell Bay area; and / or b. Commitment of new generation to connect in North West Tasmania or Central Highlands that results in higher power flows on the Palmerston – Sheffield – George Town triangle and causes a power flows through the Sheffield–Palmerston transmission corridor to be constrained to maintain network stability. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates augmenting power transfer capacity between Sheffield and Palmerston is the preferred option that provides net market benefits and / or addresses a reliability corrective action; and 3. TasNetworks' Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER. 	212
5	Address power transfer capability to George Town (Stage 2) Sheffield to George Town Network Upgrade	New load at or around George Town / Bell Bay and / or New generation in North West or Central Highlands	<ol style="list-style-type: none"> 1. One or both of the following: <ol style="list-style-type: none"> a. Commitment of additional load from one or more customers with aggregated load above 300 MW to connect to the transmission network in the George Town-Bell Bay area ; and / or b. commitment of new generation to connect in North West Tasmania or Central Highlands that results in higher power flows on the Sheffield – George Town - Palmerston triangle and causes power flows between Sheffield and George Town to be constrained to maintain flows within thermal and, or, stability limits; 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the capacity between Sheffield and George Town is the preferred option that provides positive net market benefits and / or addresses a reliability corrective action; and 3. TasNetworks' Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER. 	166

6	Address power transfer capability to George Town (Stage 3) Palmerston to George Town via Hadspen Network Upgrade	New load at or around George Town / Bell Bay and / or New generation in North West or Central Highlands	<ol style="list-style-type: none"> One or both of the following: <ol style="list-style-type: none"> Commitment of additional load from one or more customers with aggregated load above 700 MW to connect to the transmission network in the George Town-Bell Bay area; and / or commitment of new generation to connect in North West Tasmania or the Central Highlands that results in higher power flows on the Palmerston – Sheffield - George Town triangle and causes power flows on the Palmerston to George Town via Hadspen 220kV transmission line to be constrained to maintain flows within thermal limits. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the capacity of the network between Palmerston and George Town via Hadspen is the preferred option that provides positive net market benefits and / or addresses a reliability corrective action; and TasNetworks' Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER. 	209
7	Address transfer capability constraints on the Waddamana–Palmerston 220 kV corridor Waddamana–Palmerston Network Upgrade	New generation in the Central Highlands and / or southern transmission network	<ol style="list-style-type: none"> Commitment of new generation in the Central Highlands and / or the southern transmission network that results in power flow through the Waddamana–Palmerston transmission corridor to be constrained to maintain flows within thermal and/or stability limits; Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the transfer capability of the Waddamana–Palmerston transmission corridor is the option that maximises positive net market benefits; and TasNetworks' board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER. 	113

4.1 Project 1: Address network security requirements at George Town Substation

4.1.1 Background

George Town Substation is the only existing substation to supply the Bell Bay area. George Town Substation is the largest single load point in Tasmania supplying several major industrial (MI), commercial and residential customers, totalling approximately 460 MW of load. When Basslink is in full export mode, George Town Substation exports close to 1,000 MW. This is over 50 per cent of the recorded system peak of approx. 1,750 MW and around 90 per cent of the recorded system average load. Keeping such a share of load at a single location is a high risk arrangement. The addition of new large loads to George Town Substation would increase the risk further.

The existing George Town Substation has limited space for future expansions, which is not sufficient to accommodate the identified load growth in the area. The existing George Town Substation and surrounding infrastructure are shown in Figure 2. The Southern end of the substation has very limited space to extend, with restricted access unless connecting through cables, which is costlier than overhead connections. The northern end of the substation can accommodate additional diameters by relocating the existing 22 kV cables, however access limitations will still remain.

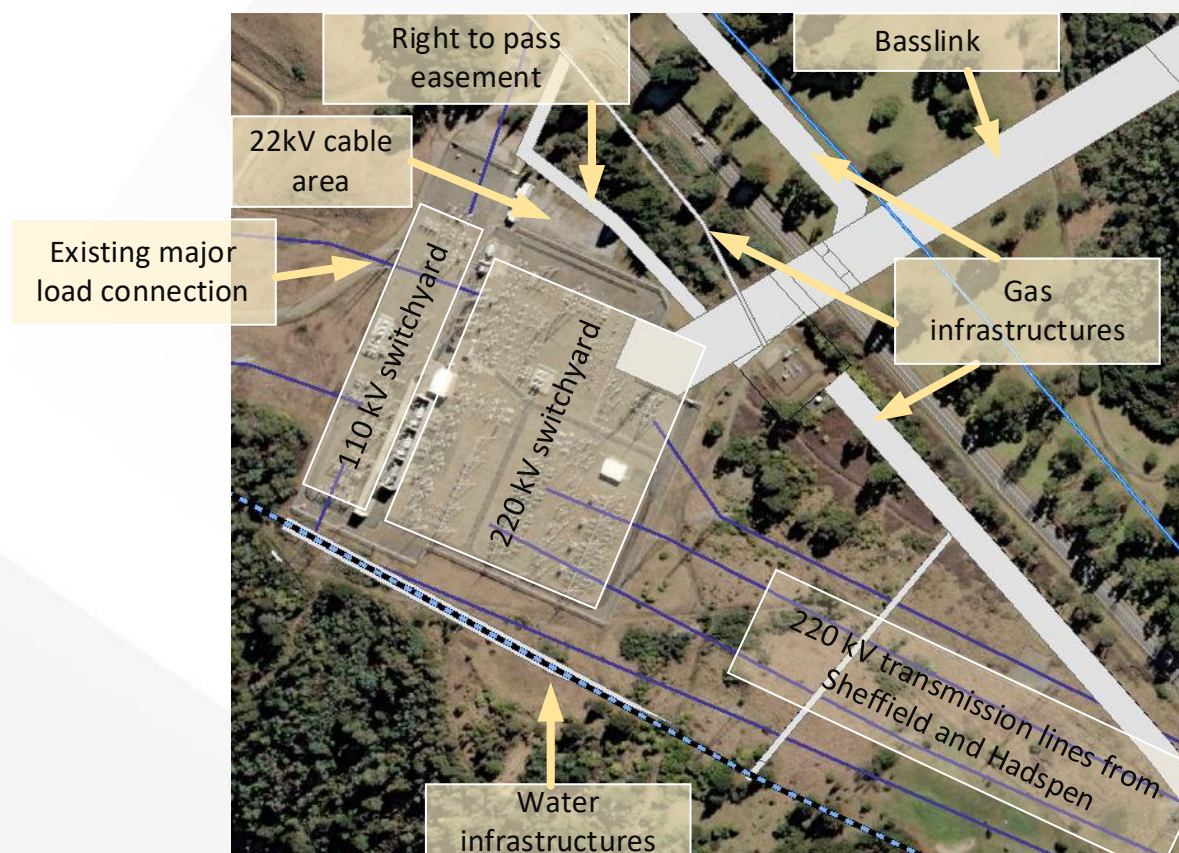


Figure 2: The existing George Town Substation and surrounding infrastructure

The network connections of the existing George Town Substation are at one end of the substation, with major load and Basslink connected at the other end. Under extreme operational situations, it is possible to split the connection between two ends of the substation; however, this would lead to a high risk state of operation.

George Town Substation is a major substation in the network, subject to high impact / low probability events that have the potential to significantly impact the rest of the network. These events become more severe when more load and generation are connected and the system becomes weak. We can expect more weak system conditions when new wind and solar developments take place within Tasmania to offset energy development of new loads.

As per the National Electricity Rules (**NER**), S5.1.8, Network Service Providers (NSP) must consider power system synchronism and voltage stability under most severe credible contingency event or any protected event in planning and operation. Furthermore, NSPs must consider non-credible contingency events such as busbar faults which result in tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies which could potentially endanger the stability of the power system.

As per *Electricity Supply Industry (Network Planning Requirements) Regulations 2018* (ESI regulations), in respect to an intact transmission system, load that is interrupted by a single asset failure is not to be capable of resulting in a black system.

Examples of low probability, high consequence events in the existing George Town substation include:

- A failure to open any circuit breaker (i.e., uncleared fault in NER and single asset failure under ESI regulations) with the possibility of loss of Basslink, a capacitor bank and a significant portion of major industrial load. This can lead to system black under weak network conditions. Any new connection at George Town Substation (load, generation, reactive support etc.) can exacerbate the current situation.
- Under a bus outage, all the loads, Basslink and lines are connected to one bus. There is no back-to-back connection of Basslink or major load against transmission circuits in the existing configuration. Major loads and Basslink flows must be restricted significantly until bus outage conditions are resolved. Otherwise, a system black event can occur under the next asset failure. Bus outages can occur under the following situations:
 - A stuck condition of any of the bus connecting breakers can lead to a bus outage;
 - Maintenance in any bus disconnectors or a bus, where a bus outage is needed; or
- Any unpredicted large scale incident (a natural disaster or sabotage) that can lead to loss of supply to all the loads connected to the substation.

The Tasmanian Government's action plan seeks to develop hydrogen hub at George Town area up to 1000 MW in progressive stages from 2024 to 2030. A number of proponents have submitted their connection enquiries and pre-enquiries to connect over 1000 MW by 2026 and over 2500 MW by 2029.

In addition to the high volume of connection enquiries from large scale load proponents, TasNetworks has also received a number of significant generator connection enquiries at George Town. The proposed augmentations identified at George Town and the proposed co-located site are necessary to optimally support both loads and generators, along with any necessary dynamic reactive support requirements, while maintaining power system security.

4.1.2 Need/likelihood

The system security issue at George Town is an existing issue, which is exacerbated by further addition of loads at George Town substation and / or new generation across the network. According to the Tasmanian government and proponents expectations, the likelihood of an initial connection of over 300 MW of load at George Town before 2026 is very high.

4.1.3 Indicative solution

The indicative solution is to rearrange the 220 kV connections at the existing George Town Substation and establish a new substation at Bell Bay area. The combined approach of a new substation and rearrangement of the existing substation will efficiently minimise network security issues to accommodate new load and generation connections, along with associated dynamic reactive support.

4.1.4 Trigger

The trigger events for this project are:

1. TasNetworks demonstrates that customer commitment of additional load to connect to the transmission network in the George Town-Bell Bay area results in:
 - a material increase in the probability of cascading failure, following non-credible contingent events, as defined in Schedule 5.1.8 of the NER; and / or
 - breaches of minimum network performance requirements under regulation 5 of the Electricity Supply Industry (Network Planning Requirements) Regulations.
2. TasNetworks demonstrates that the solution required to meet the power system security obligations cannot be accommodated within the existing layout of George Town substation.
3. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates a network investment is the most efficient option to ensure TasNetworks meets its power system security obligations at George Town under:
 - clause S5.1.8 of the NER;
 - The Electricity Supply Industry (Network Planning Requirements) Regulations;
4. TasNetworks' Board commitment to proceed with the project subject to the Australian Energy Regulator amending the revenue determination pursuant to the NER.

4.1.5 Indicative costs

The indicative cost to improve the system security at George Town is approximately \$50m.

4.2 Maintain voltage stability at George Town Substation

4.2.1 Background

The existing reactive support (capacitor banks) at George Town Substation are fully utilised to maintain voltage stability and reactive margin at George Town. According to NER, S5.1.8, NSPs must maintain sufficient reactive margin at connection points to withstand the most severe credible contingency event or any protected event.

NSPs are to select the appropriate margin at each connection point subject to the requirement that the margin must not be less than 1% of the maximum fault level. At George Town substation, new load connections in the area require additional reactive support in order to maintain transient voltage stability. Initial studies have indicated that over the projected loading range of new connections, a significant amount of reactive support is needed to maintain the target voltage at George Town Substation and system stability under network contingencies.

4.2.2 Project 2: Stage 1 (committed projects before 2026)

Steady state additional reactive power requirements were evaluated under different system conditions. Figure 3 gives the indicative reactive power requirements under steady state conditions with an additional 300 MW load at George Town for two fault level conditions at George Town (fault level contribution only from synchronous generators). 2021 historic data indicates that the George Town fault level went below 2060 MVA in 10% of the time and 2771 MVA in 70% of the time. This can be much higher with new wind developments.

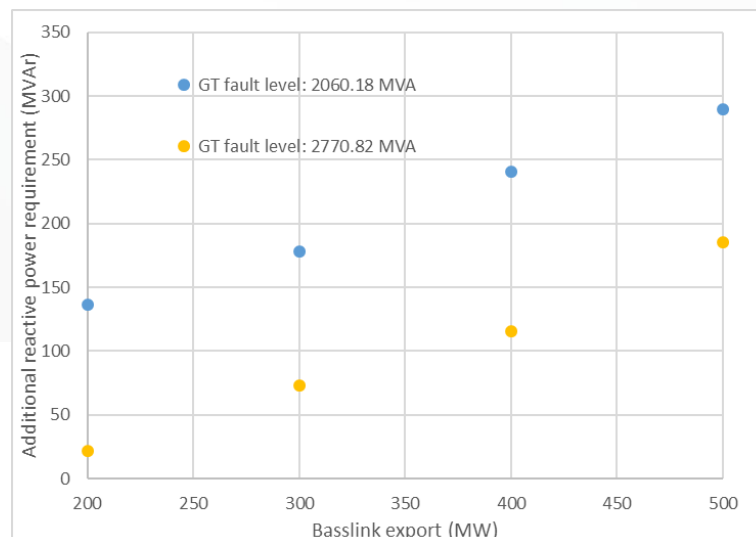


Figure 3: Steady state additional reactive power requirement for additional 300 MW load

The analysis was extended to understand the additional reactive power requirement to maintain the reactive margin. The study indicated that around 80 MVAR additional reactive support on top of the steady state requirement is needed to maintain the reactive margin at around 2000 MVA fault level at George Town. This additional requirement should be a dynamic support to maintain transient over voltage (TOV) and system stability. This can be higher under lower fault level, which can be observed quite often with further wind adding into the network. We need to have a redundancy equipment following best engineering practices in order to avoid single point of failure and loss of the support due to any other network event.

Initial studies indicated that reactive power support requirement in the area is approximately in the ratio of 1 MVAR to each 1 MW of load increase. Therefore, 300 MVAR reactive power support is required to accommodate 300 MW of additional load.

4.2.2.1 Need/likelihood

Steady state and transient voltage at George Town cannot be maintained under some generation and load patterns with the proposed load developments in George Town area. This is an immediate issue with a new large load addition. In line with the volume of new load connection enquiries from proponents at George Town, the likelihood of load connections meeting or exceeding 300 MW before 2026 is very high.

4.2.2.2 Indicative solution

The Indicative solution is to install a combination of capacitors and dynamic reactive support at George Town, to be accommodated in conjunction with augmentation works at the existing substation and new co-located substation. Approximately 300 MVAR reactive support is required to accommodate 300 MW of additional load, comprising two ± 100 MVAR STATCOMs and two 50 MVAR capacitors which will maintain steady state voltage and transient voltage stability in the area for an additional load of up to 300 MW.

4.2.2.3 Trigger

The trigger events for this project are:

1. TasNetworks demonstrates customer commitment of additional load to connect to the transmission network in the George Town-Bell Bay area will result in TasNetworks being non-compliant with power system voltage and system stability requirements at George Town with respect to clause S5.1.8 of the NER.
2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, demonstrating a network investment is the most efficient option to meet reactive support requirements at George Town under Clause S5.1.8 of the NER; and
3. TasNetworks Board commitment to proceed with the project subject to the Australian Energy Regulator amending the revenue determination pursuant to the NER.

4.2.2.4 Indicative costs

Indicative cost is in the range of \$50m to \$100m. The estimated cost to install two of ± 100 MVAR STATCOMs and two of 50 MVAR capacitors to support additional 300 MW load is approximately \$75m.

4.2.3 Project 3: Stage 2 (committed projects after 2026)

Based on connection enquiries and pre-enquiries received by TasNetworks, new loads beyond the first stage of development are forecast at George Town between 2026 and 2029. A second loading stage of up to 700 MW at George Town is projected in the later period of the 2024-2029 regulatory control period, requiring separate, additional augmentations to the network. Therefore, a separate contingent project is proposed. Further reactive support is required to support the network in the George Town area as these connections are progressed.

The quantum of additional reactive power requirements at this stage is uncertain due to associated uncertainties around possible other network and generation developments.

4.2.3.1 Need/likelihood

Steady state and transient voltage at George Town cannot be maintained under some generation and load patterns with the proposed additional load developments at George Town, beyond 300 MW. As per the load connection forecast based on proponent connection enquiries, the likelihood of connecting 700 MW during 2024 to 2029 regulatory control period is very high.

4.2.3.2 Indicative solution

Installation of capacitors and dynamic reactive support in George Town area is considered as a solution. Initial studies indicated that reactive power support requirement in the area is in the ratio of 1 MVar to 1 MW of load. A combination of two additional 100 MVar STATCOMs and four 50 MVar capacitors are considered as a solution to maintain steady state voltage and transient voltage stability in the area for an additional load of up to 700 MW. Actual requirements are to be assessed in greater detail when other associated network developments are finalised and supply sources are identified.

4.2.3.3 Trigger

The trigger events for this project are:

1. TasNetworks demonstrates that a second occurrence of load committed to connect to the transmission network in the George Town-Bell Bay area will result in TasNetworks being non-compliant with power system voltage and system stability requirements at George Town with respect to clause S5.1.8 of the NER;
2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, demonstrating a network investment is the most efficient option to meet reactive support requirements at George Town under Clause S5.1.8 of the NER; and
3. TasNetworks Board commitment to proceed with the project subject to the Australian Energy Regulator amending the revenue determination pursuant to the NER.

4.2.3.4 Indicative costs

Indicative cost to install required dynamic reactive support and the capacitors to support additional 400 MW load is around of \$80m.

4.3 Address power transfer capability to George Town

4.3.1 Background

George Town area is supplied from two 220 kV main corridors (i.e., Sheffield-George Town and Palmerston-Hadspen-George Town) and these two corridors are interconnected through Palmerston-Sheffield 220 kV line. Sheffield Substation is the major connection point from North West Renewable Energy Zone (REZ) to the rest of the network and Palmerston Substation is the major connection point from Central Highland REZ to the north. The Palmerston-Sheffield-George Town triangle is mainly considered in supplying the George Town area.

The operating characteristic of the network in this region, particularly the power sharing through the Palmerston-Sheffield-George Town network corridor necessitates the application of network constraints in the triangle in order to maintain a secure operating state. This results in constraints to the total allowable generation that can be connected in the North West and Central Highland REZs. The existing 220 kV transmission lines in the triangle and the proposed developments are shown in Figure 4.

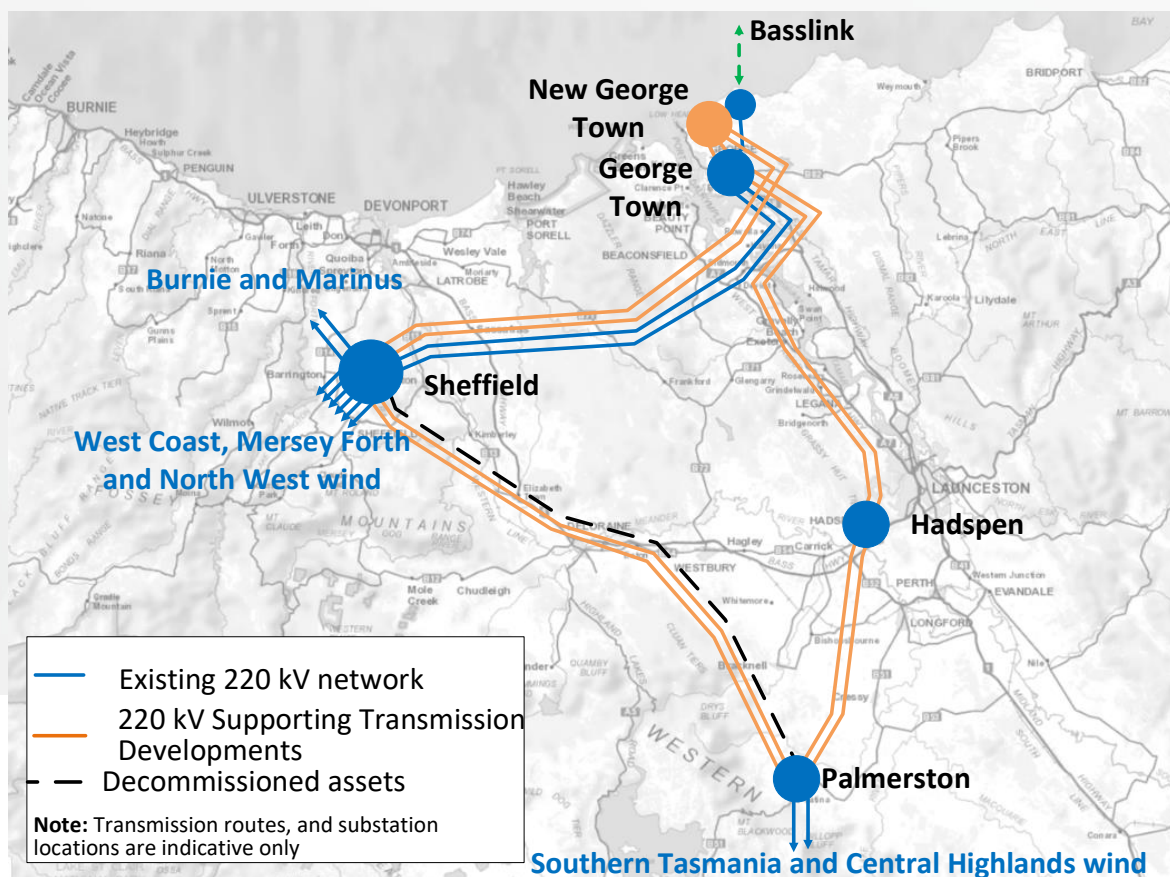


Figure 4: The existing 220 kV transmission network in the triangle and the proposed developments

The ratings of the existing 220 kV lines in the triangle are given in Table 2. The weakest link in the triangle is the Palmerston – Sheffield corridor, which has a single circuit line.

Table 2: 220 kV Transmission line connections- Northern network

Transmission element	Length (km)
Sheffield-George Town 220 kV double circuit line (TL510)	68.0
Palmerston-Sheffield 220 kV single circuit line (TL503)	78.8
Palmerston-Hadspen 220 kV double circuit line (TL509) (in parallel with 110 kV double circuit line)	33.6
Hadspen-George Town 220 kV double circuit line (TL509)	51.7

The existing network in the triangle has an available capacity to supply between 100 to 150 MW at George Town. The studies indicated that further addition of load may lead to the exposure to network security risks in the form of system stability limitations being exceeded.

The expected load developments in the George Town area need to be capable of being supplied from generation around George Town or generation in the rest of the network, in order to maintain energy neutrality in Tasmania. As per the 2022 Integrated system plan (ISP) results, the Central Highland REZ is the most likely REZ to develop first, followed by the North West REZ. If the additional load at George Town is supplied from these two REZs, flow in the triangle will increase and eventually constrain the network. These constraints can be either stability limits or thermal capacity limits.

4.3.2 Project 4: Stage 1 (committed projects before 2026)

4.3.2.1 Background

The existing Palmerston–Sheffield 220 kV transmission line (TL503) is a 79 km single circuit line, built in 1957. It uses Goat conductor strung at a 65°C design operating temperature, with a rating of 298 MVA/239 MVA (Winter/Summer). Based on existing maintenance practices, this line is expected to remain serviceable through the 2024–29 regulatory control period. TL503 is the lowest capacity section in the triangle and has started constraining supply to the George Town area as well as flow between Palmerston and Sheffield.

Palmerston – Sheffield upgrade is identified as a part of the AC network development for the first 750 MW Stage of Marinus Link in order to ensure compliance with the Electricity Supply Industry (Network Planning requirements) Regulations 2007. Without this upgrade, the possibility of a single asset failure in other transmission corridors could potentially lead to a system black event.

With new load connection into George Town area, network stability requirements need to be addressed before the first stage of Marinus Link. Historic data shows that the majority of the time, the existing system conditions are sufficient to export 500 MW through Basslink without any new loads. With the increase of load at George Town and additional wind generation across the network, system conditions are not sufficient to maintain the system stability, leading to constraint of power flows in the triangle. For example, technical studies indicate that flows in the triangle would be constrained around 25% of the time based on historic data if Basslink export capability were to be maintained at 500 MW level. If more wind is connected into the network, the duration of constraining flows would be much higher.

4.3.2.2 Need/likelihood

Based on the volume of new load connection enquiries at George Town combined with new generation enquiries, increased corridor flows through the triangle are forecast with the load increases at George Town area and generation increases in the rest of the network. Initial studies have indicated that stability constraints arise first in the triangle with these flow increases.

4.3.2.3 Indicative solution

In order to alleviate the severity of network constraints in the triangle, the augmentation of the existing Palmerston to Sheffield 220 kV corridor is proposed, consisting of a new double circuit 220 kV transmission line.

The proposed project will replace the existing single circuit Palmerston-Sheffield transmission line with a new high capacity double circuit 220 kV line. The increased capacity of the double circuit will support higher power transfer from the South of the State, allow greater hosting capacity for new generation in the North West, and increase the supportable load at George Town.

4.3.2.4 Trigger

The trigger events for this project are:

1. One or both of the following:
 - a. Commitment of additional load from one or more customers to connect to the transmission network in the George Town-Bell Bay area; and / or
 - b. Commitment of new generation to connect in North West Tasmania or Central Highlands that results in higher power flows on the Palmerston – Sheffield – George Town triangle and causes a power flows through the Sheffield–Palmerston transmission corridor to be constrained to maintain network stability.
2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates augmenting power transfer capacity between Sheffield and Palmerston is the preferred option that provides net market benefits and / or addresses a reliability corrective action; and
3. TasNetworks' Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER.

4.3.2.5 Indicative costs

The estimated cost for New Palmerston – Sheffield 220 kV double circuit line is \$212m.

4.3.3 Project 5: Stage 2 (committed projects after 2026)

4.3.3.1 Background

Palmerston – Sheffield 220 kV double circuit line development helps to increase network capacity to supply to George Town by around 100 to 150 MW. Thermal issues in the triangle can be observed if more than 200 to 300 MW of load is connected.

4.3.3.2 Need/likelihood

Based on connection enquiries and pre-enquiries received by TasNetworks, new loads beyond the first stage of development are forecast at George Town between 2026 and 2029. A second loading stage of up to 700 MW at George Town is projected in the later period of the 2024-2029 regulatory control period, requiring separate, additional augmentations to the network.

With over 300 MW of load developments in the George Town area and/or required generation development in the rest of the network, thermal capacity issues arise in the Palmerston – Hadspen – George Town 220 kV line.

4.3.3.3 Indicative solution

Network capacity to transfer power from the rest of the network to George Town is required to be increased. The indicative solution is to develop the second 220 kV double circuit line between Sheffield and George Town.

4.3.3.4 Trigger

The trigger events for this project are:

1. One or both of the following:
 - a. Commitment of additional load from one or more customers with aggregated load above 300 MW to connect to the transmission network in the George Town-Bell Bay area; and / or
 - b. commitment of new generation to connect in North West Tasmania or Central Highlands that results in higher power flows on the Sheffield – George Town - Palmerston triangle and causes power flows between Sheffield and George Town to be constrained to maintain network stability.
2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the capacity between Sheffield and George Town is the preferred option that provides positive net market benefits and / or addresses a reliability corrective action; and
3. TasNetworks Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER.

4.3.3.5 Indicative costs

The expected cost of the indicative solution is \$166m.

4.3.4 Project 6: Stage 3 (committed projects after 2028)

4.3.4.1 Background

Sheffield – George Town and Palmerston – Sheffield new double circuit transmission lines identified in the first and second stages of load increases in the George Town area provide significant amounts of thermal capacity along Palmerston – Sheffield – George Town corridor. The thermal limit of the Palmerston – Hadspen – George Town corridor remains a constraining element that limits the flows in the Sheffield-George Town-Hadspen-Palmerston triangle.

4.3.4.2 Need/likelihood

Based on connection enquiries and pre-enquiries received by TasNetworks, new loads beyond the first stage of development are forecast at George Town between 2026 and 2029. A second loading stage of up to 700 MW at George Town is projected in the later period of the 2024-2029 regulatory control period, with further increases continuing in subsequent years. As the aggregate load increases at George Town, separate, additional augmentation to the network is required to address the emerging thermal capacity issue in the Palmerston – Hadspen – George Town 220 kV line.

4.3.4.3 Indicative solution

The indicative solution is to replace the existing Palmerston – Hadspen – George Town 220 kV line with a higher capacity line or manage the thermal overload by an alternative solution.

4.3.4.4 Trigger

The trigger events for this project are:

1. One or both of the following:
 - a. Commitment of additional load from one or more customers with aggregated load above 700 MW to connect to the transmission network in the George Town-Bell Bay area; and / or
 - b. Commitment of new generation to connect in North West Tasmania or the Central Highlands
 that results in higher power flows on the Palmerston – Sheffield - George Town triangle and causes power flows on the Palmerston to George Town via Hadspen 220kV transmission line to be constrained to maintain flows within thermal limits.
2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the capacity of the network between Palmerston and George Town via Hadspen is the preferred option that provides positive net market benefits and / or addresses a reliability corrective action; and
3. TasNetworks Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER.

4.3.4.5 Indicative costs

The expected cost of the indicative solution to replace Palmerston – Hadsphen – George Town 220 kV line with a higher capacity line is \$209m.

4.4 Project 7: Waddamana–Palmerston transfer capability upgrade

4.4.1 Background

The northern (from Palmerston Substation to north) and southern (from Waddamana Substation to south) sections of the Tasmanian transmission network are tied through a single transmission corridor, between Waddamana and Palmerston substations. The Waddamana–Palmerston transmission corridor comprises a double-circuit 220 kV transmission line and single-circuit 110 kV transmission line, presented in Figure 5.

Power flow direction varies between north-to-south and south-to-north depending on the load/generation balance in southern Tasmania. The northern transmission network balances through the Basslink interconnector.

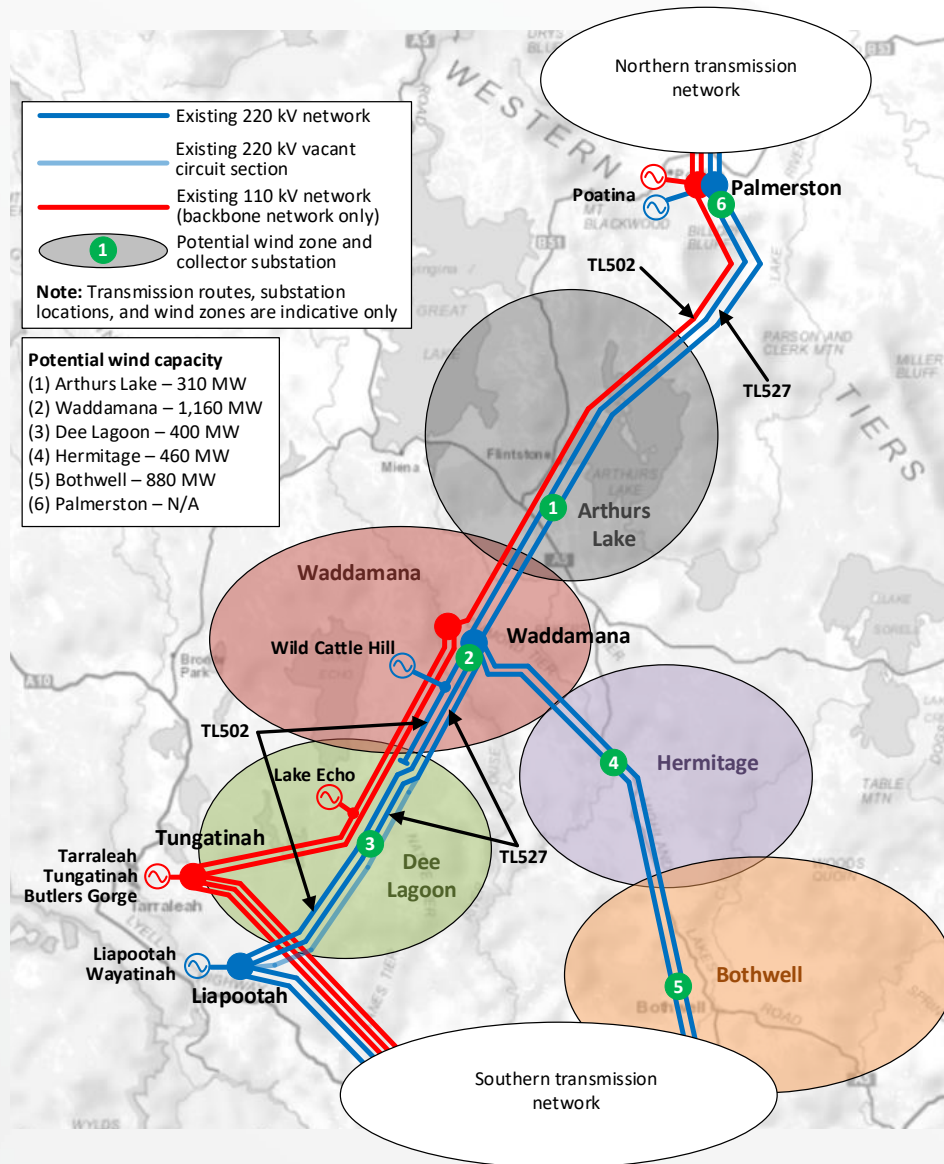


Figure 5: Central Highlands REZ and network

The Central Highlands renewable energy zone (REZ) encompasses the transmission network of Waddamana Substation and surrounds. Development of the Central Highlands REZ will occur to host new renewable energy—predominantly wind farms—to support the Tasmanian Renewable Energy Target² (TRET) and as forecast in the 2022 Integrated System Plan³ (ISP). The ISP models the Central Highlands REZ as having the highest capacity factor for new wind generation of all the REZs in the NEM.

² https://recfit.tas.gov.au/renewables/tasmanian_renewable_energy_target

³ <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp>

Figure 5 presents the ‘wind zones’ and collector stations we have identified that could reasonably accommodate the new generation required to develop the Central Highlands REZ. This shows that development of the Central Highlands REZ (with no significant load growth in the southern transmission network) will result in increased power flows northwards to Palmerston Substation through the Waddamana–Palmerston transmission corridor. Further, new wind resource could be developed in the southern transmission network (outside the defined REZ), which would also contribute to increased flows through the Waddamana–Palmerston transmission corridor.

It is likely that the increased power flows will reach a level where significant constraint is required to maintain the flows within the thermal and/or stability limits of the transmission corridor. We anticipate that the level of constraint will be significant enough that it is likely to justify a transmission augmentation solution to increase the corridor transfer capability and relieve the constraint(s). This would allow access to the low-cost wind and hydropower energy resources in the Central Highlands REZ and southern transmission network, offsetting use of more expensive generation resources elsewhere in the network.

4.4.2 Need/likelihood

The ISP forecasts a strong outlook for new generation in the Central Highlands REZ. The ISP forecasts new wind generation in excess of 1,000 MW installed capacity in the REZ by 2030.⁴

This forecast is credible, as there are currently 470 MW of publicly-announced new wind generation projects in the Central Highlands REZ and southern transmission network.⁵ Further, TasNetworks is aware of other projects (in the order of 100s of MW) undertaking preliminary feasibility work in the REZ. Other projects may materialise, with continued progress of Marinus Link and Bell Bay hydrogen hub.

With the level of new generation forecast in the ISP, there will be very large power flows from Waddamana Substation to Palmerston Substation and the rest of the network. This will result in significant transmission constraints to maintain power flow within both thermal and stability limits of the Waddamana–Palmerston transmission corridor. It is anticipated the level of constraint will be sufficient to justify a transmission augmentation to increase the power transfer capability of the corridor.

4.4.3 Indicative solution

The solution to address the identified need will be an increase of the power transfer capability in the Waddamana and Palmerston substations. The likely solution being the addition of additional 220 kV transmission circuits between the substations.

⁴ 2022 Integrated System Plan, Appendix A3 Renewable Energy Zones, T3 – Central Highlands (pages 78-79), 30 June 2022, <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp>

⁵ Table 3-3 (page 43), TasNetworks Annual Planning Report 2022, <https://www.tasnetworks.com.au/apr>

The indicative solution identified is a new, second double-circuit Waddamana–Palmerston 220 kV transmission line. It would likely be constructed in the same corridor as the existing transmission line.

4.4.4 Trigger

The trigger events for this project are:

1. Commitment of new generation in the Central Highlands and / or the southern transmission network that results in power flow through the Waddamana–Palmerston transmission corridor to be constrained to maintain flows within thermal and/or stability limits;
2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the transfer capability of the Waddamana–Palmerston transmission corridor is the option that maximises positive net market benefits; and
3. TasNetworks board commitment to proceed with the project subject, to the AER amending the revenue determination pursuant to the NER.

4.4.5 Indicative costs

A new, second double-circuit Waddamana–Palmerston 220 kV transmission line is estimated to cost \$113 million. The actual cost will depend on the full scope of the ultimate solution, and subject to the outcomes of the RIT-T.

4.5 Demonstration of Rules compliance

TasNetworks considers that our proposed contingent projects meet the requirements of Clause 6A.8.1(b) of the NER. Specifically, the projects:

- are reasonably required to be undertaken in order to achieve any of the capital expenditure objectives in the NER;
- expenditure is not otherwise provided for (either in part or in whole) in TasNetworks' forecast capex for 2024-29 regulatory control period;
- reasonably reflect the capex criteria, when considering the capex factors in the NER;
- exceed \$30 million or 5% of the value of TasNetworks' maximum allowable revenue for 2024-25; and
- have appropriate trigger events.

5 Other contingent projects

In addition to the six contingent projects noted above, TasNetworks expect two will be triggered as an actionable ISP project or as a system strength project in accordance with clauses 5.16A.5 and 11.143.18 of the Rules respectively. These projects are:

- Transmission developments required to support Project Marinus in North West Tasmania; and
- Network development required to meet the new system strength framework.

Although, these projects are triggered automatically and do not need to be included in TasNetworks' revenue proposal, we have included them here for transparency.

Table 3 provides the associated the trigger events as defined in the NER.

Table 3: Mandatory trigger events for automatically triggered projects

Project Description	Triggers
North West Transmission Development	<ol style="list-style-type: none"> 1. TasNetworks issues a project assessment conclusions report that meets the requirements of clause 5.16A.4 and which identifies a project as the preferred option (which may be a stage of an actionable ISP project if the actionable ISP project is a staged project); 2. TasNetworks obtains written confirmation from the Australian Energy Market Operator (AEMO) that: <ol style="list-style-type: none"> a. the preferred option addresses the relevant identified need specified in the most recent Integrated System Plan and aligns with the optimal development path referred to in the most recent Integrated System Plan; and b. the cost of the preferred option does not change the status of the actionable ISP project as part of the optimal development path as updated in accordance with clause 5.22.15 where applicable; 3. no dispute notice has been given to the AER under rule 5.16B(c) or, if a dispute notice has been given, then in accordance with rule 5.16B(d), the dispute has been rejected or the project assessment conclusions report has been amended and identifies that project as the preferred option; and 4. the cost of the preferred option set out in the contingent project application must be no greater than the cost considered in AEMO's assessment in subparagraph (b).
Network development for System Strength rule change	<ol style="list-style-type: none"> 1. The Board of TasNetworks has committed to proceed with the system strength project subject to the AER amending TasNetworks' revenue determination in accordance with clause 6A.8.2; 2. TasNetworks has issued a project assessment conclusions report that meets the applicable requirements of new clause 5.16A.4 and which identifies the project as the preferred option; and 3. the time period in rule 5.16B(c) for giving a dispute notice has elapsed and no dispute notice been given to the AER under rule 5.16B(c) or, if a dispute notice has been given, then in accordance with rule 5.16B(d), the dispute has been rejected or the project assessment conclusions report has been amended and identifies the system strength project as the preferred option.

5.1 Network development for system strength rule change

The transition to a low carbon NEM is seeing inverter-based resources (IBR), such as wind and solar generation as well as batteries, rapidly becoming a key part of the generation mix. As the volume of wind generation continues to expand, the number of synchronous generators required to be online at any given time will be reduced. In a Tasmanian context, this situation is further exacerbated when energy is imported via an interconnector, which is another form of IBR. Tasmania has reached a point where it is theoretically possible to supply all load without the injection of energy from any synchronous generators.

AEMO has re-assessed Tasmanian inertia and system strength requirements. It concluded that the potential for a shortfall existed for both inertia and system strength, extending over the five-year planning horizon from 2020 to 2025. AEMO subsequently issued a notice requiring TasNetworks to ensure that there are sufficient inertia network services and system strength services, to meet the declared shortfall amounts.

On 21 October 2021, the Australian Energy Market Commissions' (AEMC's) made a final determination on the efficient management for system strength on the power system. This introduced a new system standard and transmission network standard for system strength under Schedule 5.1a and Schedule 5.1 of the NER, respectively. Under the rule, TasNetworks is required to use reasonable endeavours to plan, design, operate and maintain its transmission network in order to meet network performance requirements at the locations on its network (known as system strength nodes) and the amounts of inverter-based resources (IBR) as forecast by AEMO.

The final rule included a new transitional rule that:

- deems a system strength project proposed to be undertaken by a SSS Provider in its next regulatory control period to be a contingent project for the purposes of its revenue determination for that period;
- sets out deemed 'trigger events' for that contingent project;
- provides that the SSS Provider is not required to include the proposed contingent capital expenditure for this contingent project in its revenue proposal and the AER is not required to make a determination under clause 6A.8.1(b) in relation to this contingent project.

5.2 North West Transmission Development

As part of the Project Assessment Conclusions Report for Project Marinus, TasNetworks identified the preferred option to meet the identified need as a 1500MW interconnector with the following on-island transmission developments:

- Construction of a new 220 kV switching station at Heybridge adjacent to the converter station;
- Establishment of a new 220 kV switching station at Staverton;
- Construction of a new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie;
- Construction of a new double-circuit 220 kV transmission line from Heybridge to Sheffield and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor; and
- Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield;

As part of its 2020 ISP, AEMO designated Project Marinus and the associated transmission developments as an actionable ISP project. As per the ISP, actionable projects should progress as urgently as possible. Under clause 6A.8.A1(b) of the NER, an actionable ISP project is considered a contingent project in relation to a revenue determination following the occurrence of the trigger events described in clause 5.16A.5. For Project Marinus, the only remaining trigger event is written confirmation from AEMO that the total project remains on the ISP optimal development path.

6 Distribution network contingent projects

No contingent projects have been identified for the distribution network in the 2024-29 regulatory control period.

7 Appendix A: Geographic Overview of contingent project augmentations

