Combined Proposal 2024-2029

Attachment 7
Contingent projects

Outline: This attachment to TasNetworks' regulatory combined proposal sets out how the contingent projects provisions of the National Electricity Rules will apply to TasNetworks during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
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Attachment 4	Rate of return
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7 Contingent projects

7.1 Introduction

Contingent projects are significant network augmentation projects that are reasonably likely to be required in the 2024-2029 regulatory control period but for which the timing and/or the associated costs are not sufficiently certain to warrant their inclusion in TasNetworks' capital expenditure (**capex**) forecasts. Consequently, expenditure for these projects does not form part of TasNetworks' total forecast capex in the 2024-2029 regulatory control period, but the costs of these projects may ultimately be recovered from customers if unique trigger events occur.

TasNetworks has identified seven contingent projects relating to major augmentations of our transmission network that may be required in the 2024-2029 regulatory control period. There are two additional contingent projects that are triggered automatically due to rule changes and being an actionable project in the Integrated System Plan (**ISP**). No contingent projects have been identified in relation to the distribution network for the 2024-2029 regulatory control period. The National Electricity Rules (**NER**) clauses referred to in this Attachment, therefore, relate to transmission services.

Table 1 summarises the seven contingent projects relating to major augmentations of the transmission network. The defined events that will trigger these projects are proposed in Section 7.5.2. One of the projects, the Palmerston to Sheffield Network Upgrade, also forms part of the Project Marinus Actionable ISP Project. It is also being proposed as a separate contingent project, as it may be required independently and in advance of Project Marinus. In developing this Combined Proposal, we have shared with customers and stakeholders the uncertainties associated with each of the nominated contingent projects and received their feedback.

Table 1: Summary of TasNetworks' proposed transmission network contingent projects

Contingent project	Project summary
George Town Reactive Support (Stage 1)	This project will provide dynamic reactive support to meet power system voltage and system stability requirements following new load connections in the George Town-Bell Bay area.
George Town Reactive Support (Stage 2)	Following new load connections in the George Town-Bell Bay area in excess of 300 MW, this project will provide further reactive support to meet power system voltage and system stability requirements.
George Town Substation Network Reinforcement	Following new load connections in the George Town-Bell Bay area, this project will rearrange the 220 kV connections at the existing George Town Substation and establish a new substation in the Bell Bay area to address TasNetworks' network security and performance standards obligations.
Palmerston to Sheffield Network Upgrade	This project will upgrade the transmission corridor between Palmerston and Sheffield to maintain network stability following connection of new load in the George Town-Bell Bay area or connection of new generation in north west or central Tasmania.
Sheffield to George Town Network Upgrade	This project will upgrade the transmission corridor between Sheffield and George Town to maintain network stability following connection of over 300 MW of new load in the George Town-Bell Bay area or connection of new generation in north west or central Tasmania.
Palmerston to George Town via Hadspen Network Upgrade	This project will upgrade the transmission corridor between Palmerston and George Town to address thermal capacity issues following connection of over 700 MW of new load in the George Town-Bell Bay area or connection of new generation in north west or central Tasmania.
Waddamana to Palmerston transfer capability upgrade	This project will upgrade the transmission corridor between Waddamana and Palmerston to maintain power flows within thermal and/or stability limits following connection of new generation in central or southern Tasmania.

All contingent projects relate to:

- additional renewable generation required to deliver the legislated Tasmanian Renewable Energy Target (**TRET**)[1]
- load associated with the production of green hydrogen envisioned in the State Government's Tasmanian Renewable Hydrogen Action Plan (**TRHAP**).[2]

The Tasmanian Government has set out a range of goals in its Tasmanian Renewable Energy Action Plan (**TREAP**).[3] It has also developed a Renewable Energy Coordination Framework,[4] which sets out the Government's plans to ensure that the projects needed to achieve the TRET, including development of Tasmania's Renewable Energy Zones (**REZ**), are delivered in an orderly, sustainable and integrated manner. The TRHAP 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 hydrogen production, for domestic use and export.

Together, it is these plans, as well as connection enquiries received by TasNetworks, which have informed the nomination of TasNetworks' 2024-2029 contingent projects.

7.2 Rules requirements

Most contingent projects must be identified in revenue determinations, along with indicative costing and proposed trigger event(s).[5]

Projects classified as actionable by the Australian Energy Market Operator (**AEMO**) in the ISP and projects to meet system strength requirements published by AEMO are not required to be identified in revenue determinations but are also contingent projects for the 2024-2029 regulatory control period under the NER.

7.2.1 Criteria for inclusion

For a proposed contingent project to be accepted by the AER in TasNetworks' 2024-2029 revenue determination, the project must:[6]

- be reasonably required to be undertaken in order to achieve any of the capital expenditure objectives in the NER;[7]
- not otherwise be provided for in TasNetworks' total forecast capex for 2024-2029;
- reasonably reflect the capex criteria;[8]
- involve expenditure exceeding either $30 million or five per cent of TasNetworks' maximum allowable revenue for the first year of the 2024-2029 period, whichever is greater[9]; and
- have appropriate trigger events that are reasonably specific, capable of objective verification and consistent with the identified need for each project.

7.2.2 Trigger events

When nominating a project as a contingent project, TasNetworks is required to propose the specific event(s) that will trigger the requirement to undertake the contingent project. In determining whether a trigger event proposed in relation to a nominated transmission contingent project is appropriate, the AER must have regard to the need for the event:[10]

- 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
- 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 network as a whole
- to be described in such terms that it is all that is required for the revenue determination to be amended
- 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
  - the costs associated with the event or condition are not sufficiently certain.

1 In November 2020, the Tasmanian Parliament legislated the Tasmania Renewable Energy Target which is to increase Tasmania's renewable energy output equivalent to 150 per cent of 2022's renewable energy figures by 2030 and 200 per cent by 2040

2 Department of State Growth, Tasmanian Renewable Hydrogen Action Plan, March 2020, Tasmanian Government

3 Department of State Growth, Tasmanian Renewable Energy Action Plan, December 2020, Tasmanian Government

4 Renewables, Climate and Future Industries Tasmania, Renewable Energy Coordination Framework, April 2022, Tasmanian Government

5 NER Clause 6A.8

6 NER Clause 6A.8.1 (b)

7 Capex objectives are listed in clause 6A.6.7(a) of the NER

8 Capex criteria are listed in clause 6A.6.7(c)(1)-(3) of the NER

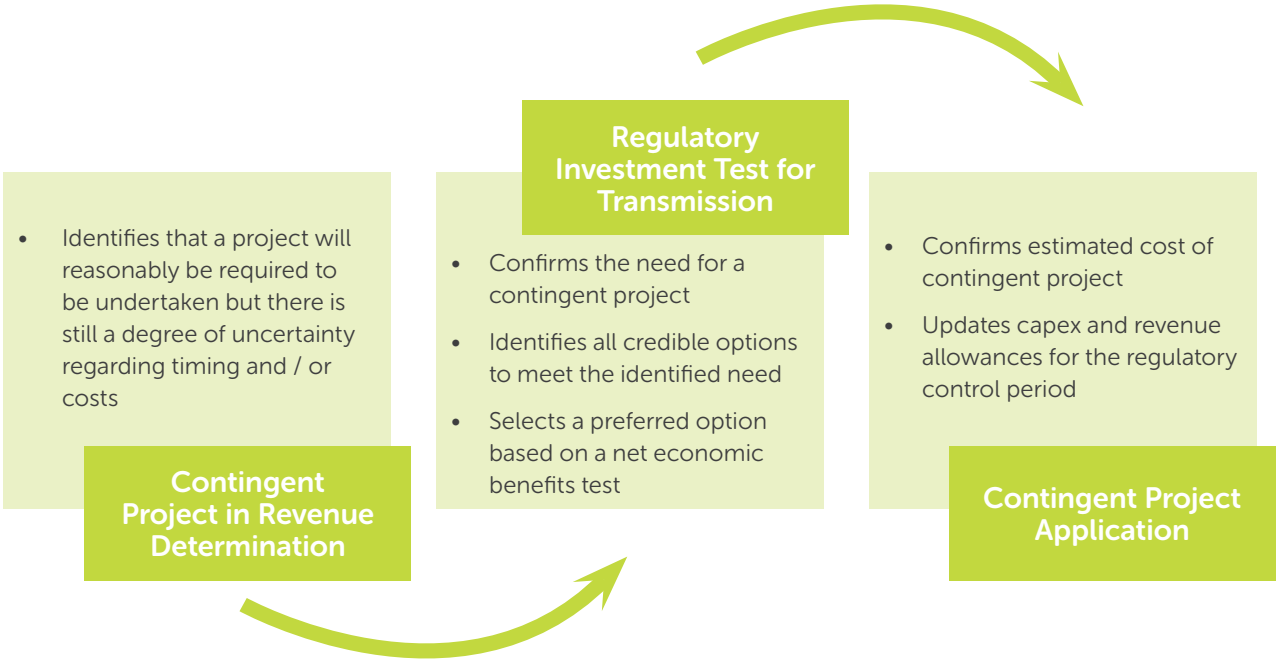
9 For TasNetworks, the contingent project threshold is $30 million

10 Clause 6A.8.1(c)

7.3 Contingent project regulatory and consultation stages

Nomination of a contingent project in a Revenue Proposal and acceptance by the AER in a Revenue Determination is the first regulatory step for major transmission projects (excluding ISP projects). Figure 1 shows the remaining regulatory steps where the project need, preferred solution and cost is further refined. Customer and other stakeholder feedback during these stages will help shape the project that will be delivered if trigger events occur during the 2024-2029 regulatory control period.

Figure 1: Contingent project regulatory and consultation stages



7.3.1 Regulatory Investment Test for Transmission

One trigger event common to all of TasNetworks' proposed transmission network contingent projects for the 2024-2029 regulatory control period is the successful completion of a Regulatory Investment Test for Transmission (**RIT-T**). The RIT-T is an economic analysis and assessment process that will identify the investment option that maximises net economic benefits in the National Electricity Market (**NEM**) while meeting the relevant service and technical standards set out in the NER or in Tasmanian jurisdictional instruments.

A key part of conducting a RIT-T is to consult with stakeholders on the economic cost benefit assessment and the ranking of investment options. Stakeholders will have opportunities as part of the RIT-T process to comment more specifically on a contingent project's need, costs, benefits and alternative solutions.

7.3.2 Contingent project application

If all triggers for a transmission network contingent project occur during the 2024-2029 regulatory control period, including successful completion of a RIT-T, TasNetworks can submit a Contingent Project Application (**CPA**) to the AER to amend its capex and operating expenditure (**opex**) allowances and annual revenue requirement for the remainder of the 2024-2029 regulatory control period.[11]
In making an application to the AER, TasNetworks must include certain details regarding the contingent project, including the forecast costs and project commencement and completion dates. The cost forecast in the CPA may differ from the estimate in this revenue proposal.

Prior to submitting a CPA to the AER, TasNetworks will engage with customers and stakeholders on project scope, costs and benefits. Customers and stakeholders will also be given an opportunity to ask questions and engage directly on the project. As noted above, stakeholders also will have the opportunity to discuss these projects as part of the RIT-T.

If the AER is satisfied that the trigger events for a specific contingent project have occurred and the forecast expenditure is prudent and efficient, it will amend TasNetworks' revenue determination for the remainder of the relevant regulatory control period.

7.4 Contingent project engagement

In developing TasNetworks' Combined Proposal, details of the nominated contingent projects have been shared with TasNetworks' Reset Advisory Committee (**RAC**), Policy and Regulatory Working Group (**PRWG**), Customer Council, Customer Panels and transmission customers during 1:1 meetings.

All groups were interested in future engagement on contingent projects with common themes being raised including:

- Project costs and benefits (all groups)
- Impacts on network charges (PRWG, Customer Council, Customer Panels and transmission customers)
- Project timeframes (PRWG, Customer Council, Customer Panels and transmission customers)
- Triggers (PRWG and Customer Council)
- Further information on the RIT-T and CPA processes (PRWG and Customer Council)
- Risks (Customer Panels).

All groups noted the need for clear and simple communication regarding contingent projects.

TasNetworks will continue to engage on contingent projects based on the feedback received so far.

7.5 Transmission network contingent projects

7.5.1 Contingent project drivers

All of the proposed contingent projects are triggered by new renewable generation and / or load. It is considered new renewable generation and load is likely to occur at large scale in Tasmania during the 2024-2029 regulatory control period, primarily driven by the TRET and the TRHAP.

This section provides further information on why it is expected that these projects will be required during the 2024-2029 regulatory control period. Further information on the implications for network capacity and costs from new generation and development of REZs in Tasmania can be found in Section 3.5 of TasNetworks' 2022 Annual Planning Report (**APR**). Section 3.6 of the APR provides further analysis on hydrogen and other load growth.

11 Clause 6A.8.2(a)

7.5.1.1 Generation growth

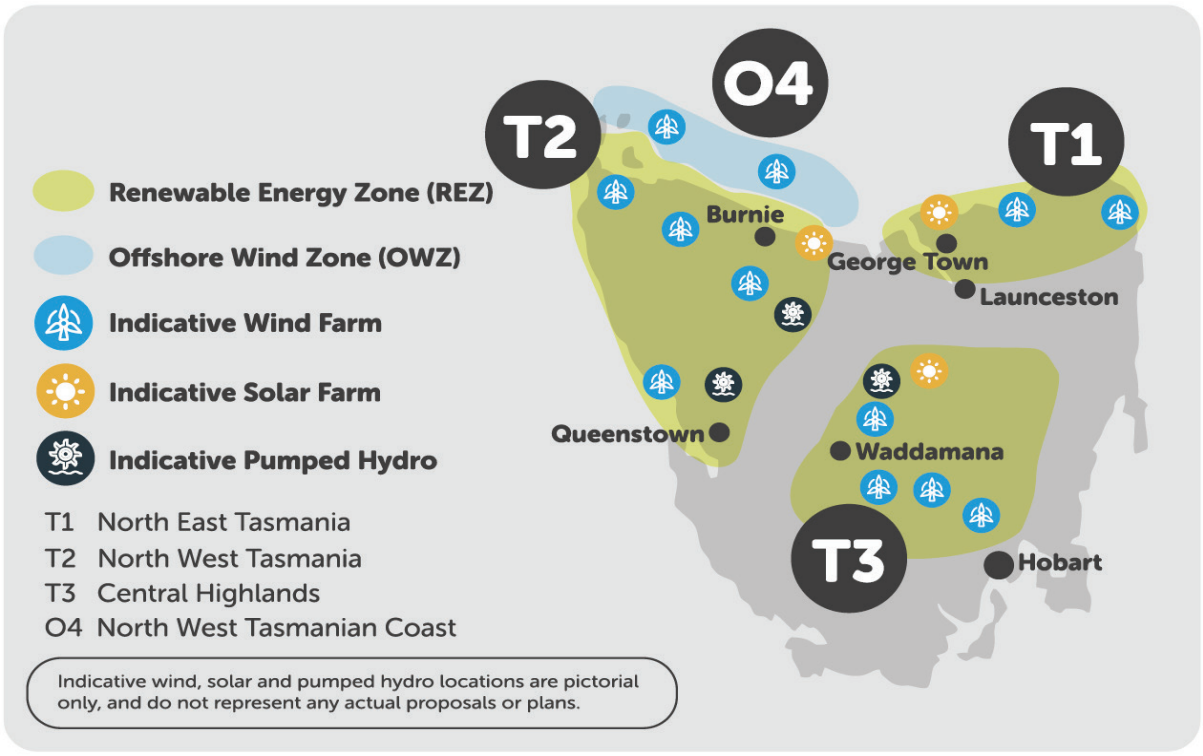
Up to four of the contingent projects are triggered by generator commitments to connect to the transmission network, noting three could also be triggered by new load in the George Town-Bell Bay area. It is expected many of these new connections will be driven by the TRET and the Renewable Energy Coordination Framework.

Under the TRET, an interim target of increasing renewable generation in Tasmania will see the output from renewable generation increase from 10,500 GWh in 2022 to 15,750 GWh in 2030. Tasmania's final legislated renewable energy target is to double renewable energy output, which will see Tasmania's renewable energy generation increase to 21,000 GWh by 2040.

The Renewable Energy Coordination Framework sets out the Tasmanian Government's plans to achieve the TRET, including development of Tasmania's REZs.

Figure 2 illustrates the location of each REZ in Tasmania as identified in the 2022 ISP.

Figure 2: Tasmanian Renewable Energy Zones[12]



The 2022 ISP forecasts 2.5 GW of new utility-scale wind generation in Tasmania by 2031-32 with 1,000 MW in the Central Highlands REZ by 2029-30 and 1,300 MW in the North West REZ by 2031-32. The contingent projects nominated in the Combined Proposal align with the ISP in that development of new generation during the 2024-2029 regulatory control period is expected in the Central Highlands and North West REZs.

A key trigger for contingent projects associated with new generation is generator commitment to connect to the transmission network. The point at which generation projects become 'committed' will be based on AEMO's five commitment criteria outlined in Table 2.

12 AEMO, Appendix 3 Renewable Energy Zones, 2022 Integrated System Plan, June 2022

Table 2: AEMO's commitment criteria for generation projects

Criteria Name	Description
Land	The project proponent has purchased / settled / acquired land for construction of the project.
Contracts	Contracts for the supply and construction of major plant or equipment components have been finalised and executed, including any provisions for cancellation payments.
Planning	The proponent has obtained all required planning consents, construction approvals, connection contracts (including approval of proposed negotiated Generator Performance Standards from AEMO under clause 5.3.4A of the NER), and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Construction	Construction of the proposal must either have commenced or a firm commencement date must have been set. Commercial use date for full operation must have been set.

7.5.1.2 Load growth

Up to six of the seven contingent projects are triggered by customer commitments of new load to connect to the transmission network in the George Town-Bell Bay area in Tasmania's north, noting that some contingent projects also could be driven by new generation in other regions of Tasmania. It is expected many of these new connections will be driven by the TRHAP.

The TRHAP contains the following goals:

1. 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
2. By 2025 to 2027 Tasmania will have begun exporting renewable hydrogen
3. From 2030 locally produced renewable hydrogen will be a significant form of energy used in Tasmania and Tasmania will be a significant global producer and exporter of renewable hydrogen.

Both the *National Hydrogen Strategy*[13] and the TRHAP recognise the importance of developing hydrogen production hubs to leverage existing infrastructure and develop the industry. Tasmania has a number of locations that are well suited to large-scale hydrogen production, including the Bell Bay Advanced Manufacturing Zone (**BBAMZ**) in northern Tasmania.

The BBAMZ has been identified as the most suitable site for a potential hydrogen hub in Tasmania, due to its access to:

- certifiable renewable energy
- high-quality fresh water
- significant vacant industrial land near deep-water port facilities.

TasNetworks has seen significant interest from proponents looking to produce hydrogen in the BBAMZ. TasNetworks has received connection enquiries and pre-enquiries for hydrogen connections totalling over 2,500 MW and expects a number of these projects to become committed during the 2024-2029 regulatory control period. The interest from potential hydrogen proponents for transmission network connections exceeds the existing available network capacity supplying the Bell Bay area, and some level of network augmentation will be required.

Based on connection enquiries and aligning with the TRHAP, TasNetworks expects hydrogen production facilities to develop in the BBAMZ in three stages:

- Stage 1: 300 MW by 2026
- Stage 2: 700 MW by 2028
- Stage 3: 1,000 MW by 2030.

A key trigger for contingent projects associated with new load is load commitment to connect to the transmission network. A new load project will be considered 'committed' when there is a firm commitment between TasNetworks and the connection applicant regarding the connection.[14] Table 3 outlines the criteria used to determine the stage at which this has occurred.

13 Coalition of Australian Governments Energy Council, Australia's National Hydrogen Strategy, 2019, Commonwealth Government of Australia

14 TasNetworks Guide to Transmission Connections, Pg 14

Table 3: TasNetworks' commitment criteria for new load connections

Criteria	Description
Site	The applicant has firm rights to the land on which the project will be constructed.
Connection application	The applicant has submitted a complete connection application to TasNetworks.
Suppliers	The applicant has selected suppliers of major plant or equipment components, nominated primary plant, and provided associated models to TasNetworks.
Planning and approvals	The applicant has obtained all required planning and construction consents able to be obtained during this development period. This does not include consents and approvals required immediately prior to, or after, construction has begun. Performance standards for the facility (which ultimately require approval by TasNetworks and AEMO) have progressed to a stage where there are no material issues preventing connection, as determined by TasNetworks acting reasonably.
Commitment to proceed	The applicant and TasNetworks have each obtained Board approvals for the connection. TasNetworks and the applicant have signed an Asset Development Agreement and Connection Agreement. All applicant-controlled conditions precedent of the Asset Development Agreement have been satisfied within the nominated timeframe.
Finance	The applicant has achieved a positive investment decision, with written confirmation provided on behalf of the applicant and any financiers.

7.5.2 Proposed contingent projects

Table 4 outlines the drivers, trigger events and indicative costs of the proposed contingent projects. This is followed by a high-level overview of each proposed contingent project. Further background on the network locations relevant to TasNetworks' proposed contingent projects is provided in Attachment 23.

The cost estimates in Table 4 are based on the indicative project descriptions. The actual costs of fully scoped solutions are subject to the outcomes of the RIT-T and project tendering and procurement processes. When the specified trigger events for a contingent project occur during the 2024-2029 regulatory control period, detailed project scope and cost estimates will be provided during the CPA process. Customers and other stakeholders will have an opportunity to comment on the project scope and cost estimates during the development of the RIT-T and the CPA.

TasNetworks considers the proposed contingent projects meet the requirements of Clause 6A.8.1(b) of the NER and the associated trigger events to be appropriate for the purposes of Clause 6A.8.1(c).

Table 4: TasNetworks' proposed contingent projects, drivers, triggers and indicative costs

Project	Driver	Triggers	Indicative cost
George Town Reactive Support (Stage 1)	New load in the George Town-Bell Bay area	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. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$75m
George Town Reactive Support (Stage 2)	New load in the George Town-Bell Bay area	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 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$80m
George Town Substation Network Reinforcement	New load in the George Town-Bell Bay area	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 clause S5.1.8 of the NER • 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 AER amending the revenue determination pursuant to the NER	$50m

Project	Driver	Triggers	Indicative cost
Palmerston to Sheffield Network Upgrade	New load in the George Town-Bell Bay area and / or New generation in North West or Central Highlands	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 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 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. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$212m
Sheffield to George Town Network Upgrade	New load in the George Town-Bell Bay area and / or New generation in North West or Central Highlands	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 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. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$166m

Project	Driver	Triggers	Indicative cost
Palmerston to George Town via Hadspen Network Upgrade	New load in the George Town-Bell Bay area and / or New generation in North West or Central Highlands	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 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. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$209m
Waddamana to Palmerston transfer capability upgrade	New generation in the Central Highlands and / or southern transmission network	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. 3. TasNetworks' board commitment to proceed with the project subject, to the AER amending the revenue determination pursuant to the NER.	$113m

7.5.2.1 George Town area reactive support (Stage 1)

Background

Clause S5.1.8 of the NER requires TasNetworks to maintain an adequate reactive power margin at every connection point in the network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point.

The existing reactive support (capacitor banks) at George Town Substation is fully utilised to maintain voltage stability in the area. Any additional load in the area will need additional reactive support to maintain the transient voltage through the existing capacitor banks.

TasNetworks' analysis indicates that a significant amount of reactive support is needed to maintain the target voltage at George Town Substation and system stability under network contingencies.

Need

Additional dynamic reactive support is needed to facilitate future load growth and reduce the occurrence of Basslink export constraints. It is likely the reactive power margin will be breached following the addition of any new load connection in the George Town-Bell Bay area. Consistent with projected hydrogen growth, additional reactive support may be required before 2026.

Indicative solution

Although the quantity of voltage support required will be determined by the quantum of committed load, it will still need to be established in blocks that are both technically and economically efficient.

Initial studies indicate that the reactive power support requirement in the area is in the ratio of 1 MVAr to each 1 MW of load increase. Although, any additional load will trigger the need for reactive support, TasNetworks considers 300 MVAr is appropriate to align with the expectation of 300 MW of new hydrogen by 2026, while meeting TasNetworks' obligations under clause S5.1.8 of the NER. The installation of two ±100 MVAr STATCOMs and two 50 MVAr capacitors at George Town are considered as an indicative solution to maintain steady state voltage and transient voltage stability in the area for an additional load of up to 300 MW.

Indicative cost

The indicative cost to install required dynamic reactive support and the capacitors needed to support an additional 300 MW of load is $75 million.

7.5.2.2 George Town area reactive support (Stage 2)

Background

Clause S5.1.8 of the NER requires TasNetworks to maintain an adequate reactive power margin at every connection point in the network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point.

New loads in the George Town-Bell Bay area beyond the first stage of hydrogen development will require installation of additional reactive support. As this is expected to occur several years after the installation of the initial reactive support, TasNetworks has proposed another contingent project to coincide with the second stage of hydrogen development.

Need

Following the installation of an initial 300 MVAr of reactive support, steady state and transient voltage at George Town may not be able to be maintained under some generation and load patterns with the proposed load developments in the George Town-Bell Bay area. Additional dynamic reactive support is needed to facilitate future load growth above 300 MW and reduce the occurrence of Basslink export constraints. It is likely the reactive power margin will be breached following the addition of any new load connection(s) involving more than 300 MW in the George Town-Bell Bay area. Consistent with Tasmanian Government objectives, additional reactive support could, therefore, be required before 2028.

Indicative solution

Initial studies indicate that the reactive power support requirement in the area is in the order of 1 MVAr to 1 MW of load. Although any additional load in the area will trigger the need for reactive support, TasNetworks considers 400 MVAr of additional reactive support would be sufficient to cater for the addition of 700 MW of new load associated with the production of green hydrogen by 2028, while still meeting TasNetworks' obligations under clause S5.1.8. The amount of reactive power required will become clearer following confirmation of other network and generation developments. An additional two ±100 MVAr STATCOMs and four 50 MVAr capacitors at George Town are considered sufficient to maintain steady state voltage and transient voltage stability in the area for additional load of up to 700 MW.

Indicative cost

The cost to install the dynamic reactive support and the capacitors required to support an additional 400 MW of load in the George Town-Bell Bay area is estimated to be $80 million.

7.5.2.3 George Town Substation network reinforcement

Background

George Town Substation is the only substation supplying the Bell Bay area and is the largest single load point in Tasmania, having around 460 MW of relatively constant load. There are risks to the Tasmanian power system associated with having such a large share of the State's load at a single location.

Currently, the network connections and major industrial loads (as well as Basslink) are connected at opposite ends of the existing George Town Substation. This configuration raises network security risks under certain low probability conditions and the level of risk will increase as additional loads are connected.

There are currently insufficient available/spare bays at the existing substation to facilitate the three stages of hydrogen connections envisaged in the Tasmanian Government's TRHAP by 2030 and the required reactive support associated with that load. In addition, the surrounding infrastructure limits further expansion of the substation to accommodate additional bays.

Need

Under clause S5.1.8, TasNetworks must consider non-credible contingency events, such as busbar faults, which might result in the tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies which could potentially endanger the stability of the power system. Furthermore, under regulation 5 of the *Tasmanian 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.

It is expected that any additional load connection in the George Town-Bell Bay area would exacerbate the existing network security issues and require intervention to meet TasNetworks' regulatory obligations.

In general, two substation bays would be required to connect 300 MW of load and to maintain maximum contingency size in Tasmania. Given four additional bays will also be required for the first stage of reactive support, maintaining system security without augmentation is not feasible.

Indicative solution

TasNetworks preferred means of addressing the risks to the power system associated with the connection of additional industrial load in the George Town-Bell Bay area is currently to rearrange the 220 kV connections at the existing George Town Substation and establish a second substation in the Bell Bay area. The rearrangement of the existing substation will partially solve the problems associated with load growth driven by the industrialised production of hydrogen, but a new substation will be required to minimise the aforementioned network security issues and accommodate reactive support developments if the new connections envisaged in the TRHAP eventuate.

Indicative cost

The indicative cost of the proposed solution is $50 million.

7.5.2.4 Palmerston to Sheffield network upgrade

Background

The George Town-Bell Bay area is supplied from two 220 kV main corridors (Sheffield-George Town and Palmerston-Hadspen-George Town), which are interconnected through the Palmerston-Sheffield 220 kV line. This is known as the Palmerston-Sheffield-George Town triangle. The Palmerston–Sheffield 220 kV transmission line is single-circuit only and has a lower thermal capacity than the other circuits in the triangle. It also plays a major role in transient stability constraints, given that loss of this circuit dramatically increases the transmission distance between Sheffield and Palmerston. It will become a constraining element in a future network state when increased power flows are needed across the network.

The Palmerston to Sheffield line is a component of the transmission works required to support Project Marinus. As such, it is captured under the actionable ISP project framework and associated Project Marinus RIT-T. Because the Palmerston to Sheffield network upgrade may be required prior to the commissioning of Marinus Link to support additional generation and/or load, TasNetworks is also proposing it as a contingent project in the 2024-2029 regulatory control period, with its own unique triggers, independent of Project Marinus.

Need

The Palmerston to Sheffield Network Upgrade is required to support both new load growth in the George Town-Bell Bay area and, or, new wind developments in the North West.

As per the ISP, wind generation is most likely to develop in the Central Highlands REZ first and then the North West. If the additional load in the George Town-Bell Bay area is supplied from these two areas, flow in the Palmerston-Sheffield-George Town triangle will increase and eventually need to be constrained to maintain the network within either its stability or thermal limits. Upgrading the Palmerston to Sheffield line will relieve these constraints.

Additional connection of generation at the Sheffield Substation may lead to network flows in the Palmerston-Sheffield-George Town triangle being constrained to maintain power flows within thermal and/or stability limits. These limits change continuously and are dependent on load and generation dispatch, Basslink operation, and the status of reactive plant. The project will be triggered when the value of the generation constrained (calculated as the amount of generation multiplied by the cost at the time) exceeds the cost of the augmentation. The level of constraint may be sufficient to justify a transmission augmentation to increase the power transfer capability of the corridor at some time during the 2024-2029 regulatory control period and may be required in advance of Project Marinus. As at December 2022 there is 1,977 MW of publicly announced generation projects in the North West and TasNetworks expects significant new wind generation to connect by 2026.

Indicative solution

In order to alleviate the severity of network constraints in the triangle, augmentation of the existing Palmerston to Sheffield 220 kV corridor is proposed, consisting of a new double circuit 220 kV transmission line. This is consistent with the solution identified as part of the Project Marinus RIT-T, noting that a separate RIT-T will be required if the Palmerston to Sheffield upgrade occurs in advance of Project Marinus for a different identified need.

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 transfers from new generation, allow greater hosting capacity for new generation in the North West, and support new load commitments in the George Town-Bell Bay area.

Indicative cost

The indicative project cost is $212 million, which is consistent with the Palmerston to Sheffield component of Project Marinus' estimated cost in the ISP.

7.5.2.5 Sheffield to George Town network upgrade

Background

Following the Palmerston to Sheffield corridor, the next most constraining component of the Palmerston-Sheffiled-George Town triangle is the Sheffield-George Town 220 kV transmission corridor. The Sheffield to George Town line supplies load in George Town-Bell Bay from generation located in North West, West Coast and central Tasmania. Thermal issues in the Sheffield to George Town corridor are expected if more than 200 to 300 MW of load is connected in the George Town-Bell Bay area.

Need

Additional hydrogen load in excess of 300 MW at George Town-Bell Bay and/or generation development in North West or Central Tasmania will result higher power flows towards George Town through the Sheffield to George Town corridor of the triangle. This will introduce thermal issues on the Sheffield-George Town 220 kV line. With larger load and generation present in the network, contingent events such as loss of single or multiple circuits in the triangle will create stability issues on the Sheffield to George Town line. The TRHAP envisions 700 MW of new hydrogen load by 2028.

Indicative solution

TasNetworks expects the preferred solution would be to develop a second 220 kV double circuit line between Sheffield and George Town.

Indicative cost

The expected cost of the indicative solution is $166 million.

7.5.2.6 Palmerston to George Town via Hadspen network upgrade

Background

The Palmerston-Sheffield and Sheffield-George Town new double circuit transmission lines identified in the first and second hydrogen stages will provide a significant amount of thermal capacity along the Palmerston-Sheffield-George Town triangle. However, further hydrogen connections may require additional upgrades. The Palmerston-Hadspen-George Town line connects George Town-Bell Bay to the network not already supplied by the Sheffield-George Town line.

Need

Additional hydrogen load in excess of 700 MW and/or generation development in North West or Central Tasmania will result in thermal capacity issues on the Palmerston-Hadspen-George Town 220 kV line. The Tasmanian Government's TRHAP envisages the arrival of 1,000 MW of new hydrogen-related load in Tasmania by 2030. Based on this timeline, TasNetworks expects that over 700 MW of additional load will potentially require connection to the transmission network during the 2024-2029 regulatory control period.

Indicative solution

The indicative solution currently favoured by TasNetworks to address the thermal capacity issues associated with additional loads of more than 700 MW involves replacement of the existing Palmerston-Hadspen-George Town 220 kV line with a higher capacity line.

Indicative cost

It is estimated that replacement of the Palmerston-Hadspen-George Town 220 kV line with a higher capacity would cost $209 million.

7.5.2.7 Waddamana–Palmerston transfer capability upgrade

Background

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

New generation in the Central Highlands REZ area identified in the ISP is likely to make a significant contribution towards achieving the renewable generation targets legislated under the TRET. The ISP forecasts new wind generation in excess of 1,000 MW installed capacity in the Central Highlands REZ by 2030.

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

Need

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. These limits change continuously and are dependent on load and generation dispatch and the status of reactive plant. The Waddamana–Palmerston Transfer Capability Upgrade will be triggered when the value of the generation constrained (the amount of generation multiplied by the cost at the time) exceeds that of the augmentation. It is anticipated the level of constraint will be sufficient to justify a transmission augmentation to increase the power transfer capability of the corridor during the 2024-2029 regulatory control period.

Indicative solution

TasNetworks' indicative solution is the construction of an additional double-circuit Waddamana–Palmerston 220 kV transmission line to complement the existing double-circuit 220 kV and single-circuit 110 kV transmission lines.

Indicative cost

A second double-circuit Waddamana–Palmerston 220 kV transmission line is estimated to cost $113 million.

7.5.3 Other contingent projects

In addition to the seven contingent projects noted above, TasNetworks expects that two projects 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 NER respectively. These projects are:

1. Transmission developments required to support Project Marinus in North-West Tasmania
2. 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, information is provided in this section to give stakeholders full insight into all projects that may be required during the 2024-2029 regulatory control period.

Table 5 provides a brief overview of each of the above projects and the associated trigger events as defined in the NER.

Table 5: Other contingent projects

Project Name	Project Description	Triggers
North West Transmission Development	This project involves the construction of the following 220 kV transmission lines in North-West Tasmania to support the Marinus Link Interconnector. • Palmerston to Sheffield • Sheffield to Staverton • Staverton to Hampshire Hills • Hampshire Hills to Burnie • Burnie to Heybridge • Sheffield to Heybridge This project is considered an actionable ISP project in the 2022 ISP.	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) [**COMPLETE**] 2. TasNetworks obtains written confirmation from AEMO that: 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 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 [**COMPLETE**] 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	This project will reflect the necessary investment needed for TasNetworks to meet the new system strength standard. At this stage, the scope of this investment including any network or non-network options are unknown. The costs are also unknown at this stage.	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. 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.

7.5.3.1 North West Transmission Development

The North West Transmission Developments include the Tasmanian transmission developments to support new and existing renewable energy developments, including Marinus Link.

The developments formed part of the Project Marinus RIT-T. The new interconnector between Tasmania and Victoria is being progressed by Marinus Link Pty Ltd and, therefore, does not form part of TasNetworks' 2024-2029 Combined Proposal.

The preferred option identified through the Project Marinus RIT-T included 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 Palmerston to Sheffield
- 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.

As part of the 2022 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.

7.5.3.2 System strength

On 21 October 2021, the Australian Energy Market Commission (**AEMC**) 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 to meet the system strength standard specified by AEMO.

The final rule included a new transitional rule that:

- deems a system strength project proposed to be undertaken by a System Strength Service Provider (**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.

7.6 Distribution network contingent projects

No contingent projects have been identified for the distribution network in the 2024-2029 regulatory control period.

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