TasNetworks 2024–29 Contingent Projects

Trigger Evaluation

Date: November 2023
Version Number: 2.0

Executive Summary

In response to the Australian Energy Regulator (**AER's**) Draft Decision on our Original Proposal, TasNetworks has undertaken technical and economic studies to refine the trigger events associated with our nominated contingent projects. Although the need for these projects continue to be driven by the connection of new load and generation in our transmission network, TasNetworks has undertaken further analysis to quantify the volume of new connections at exact locations in our network that trigger these specific projects.

We have added one further contingent project to support proposed new wind generation and industrial load to Hampshire in north-west Tasmania, following the recent scope change of the North West Transmission Developments supporting Marinus Link.

George Town Network Upgrade/Palmerston to Sheffield Network Upgrade

TasNetworks' analysis demonstrates that the existing network has very limited capacity to accommodate any new load connections in George Town. In particular, new load connections may result in TasNetworks being non-compliant with our reliability obligations under Tasmanian planning criteria. Our analysis demonstrates that 210 MW of new load connecting in George Town would lead to non-compliance with our reliability obligations and trigger the following projects:

- Establishment of a new substation and rearranging the existing George Town substation;
- Additional reactive support at George Town; and
- A new double circuit 220 kV transmission line between Palmerston and Sheffield.

TasNetworks has combined the substation and reactive support augmentations into a single contingent project called George Town Network Upgrade.

The new Palmerston to Sheffield line remains as a separate project given it could also be delivered through Project Marinus. TasNetworks considers proposing this augmentation as a separate contingent project provides transparency for customers.

George Town Reactive Support

Despite the above investments, the reactive power requirement will continue to grow as new load connects at George Town. We consider a further 140 MW of new load (ie. a total 350 MW increase from current load) is sufficient to introduce stability constraints and trigger the requirement for further reactive support investment.

Sheffield–George Town Network Upgrade

As load continues to grow in George Town, thermal issues in the network will begin to emerge. As a consequence, constraints will begin to bind more frequently to maintain the network within thermal limits. Following the Palmerston to Sheffield Network Upgrade, the next most constraining components of supplying George Town are the Sheffield–George Town and Palmerston–Hadspen–George Town transmission corridors.

TasNetworks considers the cost of transmission constraints following connection of 712 MW of new load at George Town would be sufficient to trigger the development of a second 220 kV double circuit line between Sheffield and George Town to eliminate these thermal limits.

Waddamana to Palmerston Transfer Capability Upgrade

The Australian Energy Market Operator's Integrated System Plan 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 1,751 MW of publicly announced new wind generation projects in the Central Highlands REZ and southern transmission network. With this level of new generation, 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.

TasNetworks considers 660 MW of new generation in the Central Highlands Renewable Energy Zone is sufficient to introduce constraints on the Waddamana to Palmerston transmission line.

North West Network Upgrade

A number of new wind generation and load proposals in north-west Tasmania propose to connect at Hampshire. Previously, these would have utilised the new 220 kV network of the North West Transmission Developments being established to support Marinus Link. Recently, the staging of the North West Transmission Developments has been revised to utilise an alternate route to Marinus Link in stage 1. Consequently the proposed new generation and load only have a weak 110 kV network to facilitate their connections. This will result in substantial constraints on the proposed connections. This new contingent project of North West Network Upgrade will relieve these constraints and facilitate the new proposed generation and load operation.

TasNetworks considers 100 MW of new generation or load to connect at Hampshire is sufficient to introduce constraints on the existing Burnie–Hampshire 110 kV transmission line.

Contents

1 Introduction

TasNetworks submitted our Original Proposal to the AER in January 2023. As part of our proposal, we included seven contingent projects that we considered were required to support new load and generation growth in Tasmania. A description of these projects is provided in Chapter 7 of our Original Proposal[1].

Following the AER's Draft Decision, TasNetworks has undertaken further technical and economic studies to better understand the specific quantum of new load or generation that triggers the need to pursue these projects. Furthermore, TasNetworks has identified a need of another contingent project to facilitate load and generation developments at Hampshire in north-west Tasmania.

The purpose of this document is to provide details of the analysis to derive the updated triggers and the trigger for the proposed new contingent project. It will explain why the triggers have changed in response to the AER's Draft Decision.

1.1 Key changes since Original Proposal

A summary of the changes to the triggers for these projects since the Draft Decision are provided in Table 1-1. The effect of these changes to the wording of the triggers are provided in Appendix A.

Table 1-1: Changes to TasNetworks' 2024-2029 contingent projects since the AER's Draft Decision

Project	Changes from Draft Decision
George Town Substation Network Reinforcement George Town Reactive Support (Stage 1)	These projects have been combined into a single contingent project called George Town Network Upgrade. TasNetworks considers 210 MW of new load connecting at George Town would lead to non-compliance with our reliability obligations.
Palmerston–Sheffield Network Upgrade	TasNetworks considers 210 MW of new load connecting at George Town would lead to non-compliance with our reliability obligations.
George Town Reactive Support (Stage 2)	TasNetworks considers 350 MW of new load connecting to the George Town is sufficient to introduce system stability constraints at George Town.
Sheffield–George Town Network Upgrade	TasNetworks considers the cost of transmission constraints following connection of 712 MW of new load at George Town would be sufficient to justify pursuing this project.
Palmerston to George Town via Hadspen Network Upgrade	This project has been removed. We are expecting to improve the Sheffield–George Town corridor utilization by adding series reactors in the Palmerston–George Town via Hadspen corridor.
Waddamana to Palmerston transfer capability upgrade	TasNetworks considers 660 MW of new generation in the Central Highlands Renewable Energy Zone is sufficient to introduce constraints on the Waddamana to Palmerston transmission line.

[1] https://www.aer.gov.au/system/files/TasNetworks-Combined%20Proposal%20Attachment%207%20-%20Contingent%20projects-Jan%2023-Public.pdf

Project	Changes from Draft Decision
North West Network Upgrade	This project is additional to the Original Proposal. This project is identified to support new generation and load development at Hampshire following the changes of development stages in North West Transmission Developments supporting Marinus Link.

2 Overview of George Town transmission network

The Tasmanian Government has developed the Tasmanian Renewable Hydrogen Action Plan (**TRHAP**), which describes the government vision to capitalise on low-cost reliable renewable energy resources to establish a Tasmanian hydrogen industry[2].

TRHAP has three stage goals:

- commence production of renewable hydrogen in 2022 to 2024;
- commence hydrogen export in 2025 to 2027; and
- be a significant global producer and exporter of renewable hydrogen from 2030.

Furthermore, TRHAP considers a 1000 MW facility could be feasible in George Town. The Tasmanian Government has received a $70 million grant from the Australian Government to establish the first Tasmanian hydrogen hub at Bell Bay, near George Town in Tasmania's North East.

Large-scale hydrogen production facilities in George Town will require transmission augmentation. TasNetworks submitted a set of contingent projects in our 2024–29 Original Proposal to address the network requirement to facilitate hydrogen developments in George Town.

George Town Substation is the only substation to supply loads in and around George Town and Bell Bay. George Town Substation provides the connections to load and generator customers and Basslink, the HVDC interconnector which links the Tasmanian and Victorian networks.

2.1 Transmission network

George Town Substation 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 the Palmerston–Sheffield 220 kV line. Therefore, the Palmerston–Sheffield–George Town–Hadspen transmission loop capacity is mainly evaluated to identify the transmission network limitations (Figure 2-1). Ratings and other information of the existing circuits of these corridors are given in Table 2-1. Sheffield Substation is considered as the main connection point to North West REZ from rest of the network. The main connection point from south to rest of the network is Palmerston Substation. The main connection point to Central Highlands REZ is Waddamana Substation, which is further south from Palmerston Substation.

[2] https://recfit.tas.gov.au/future_industries/green_hydrogen

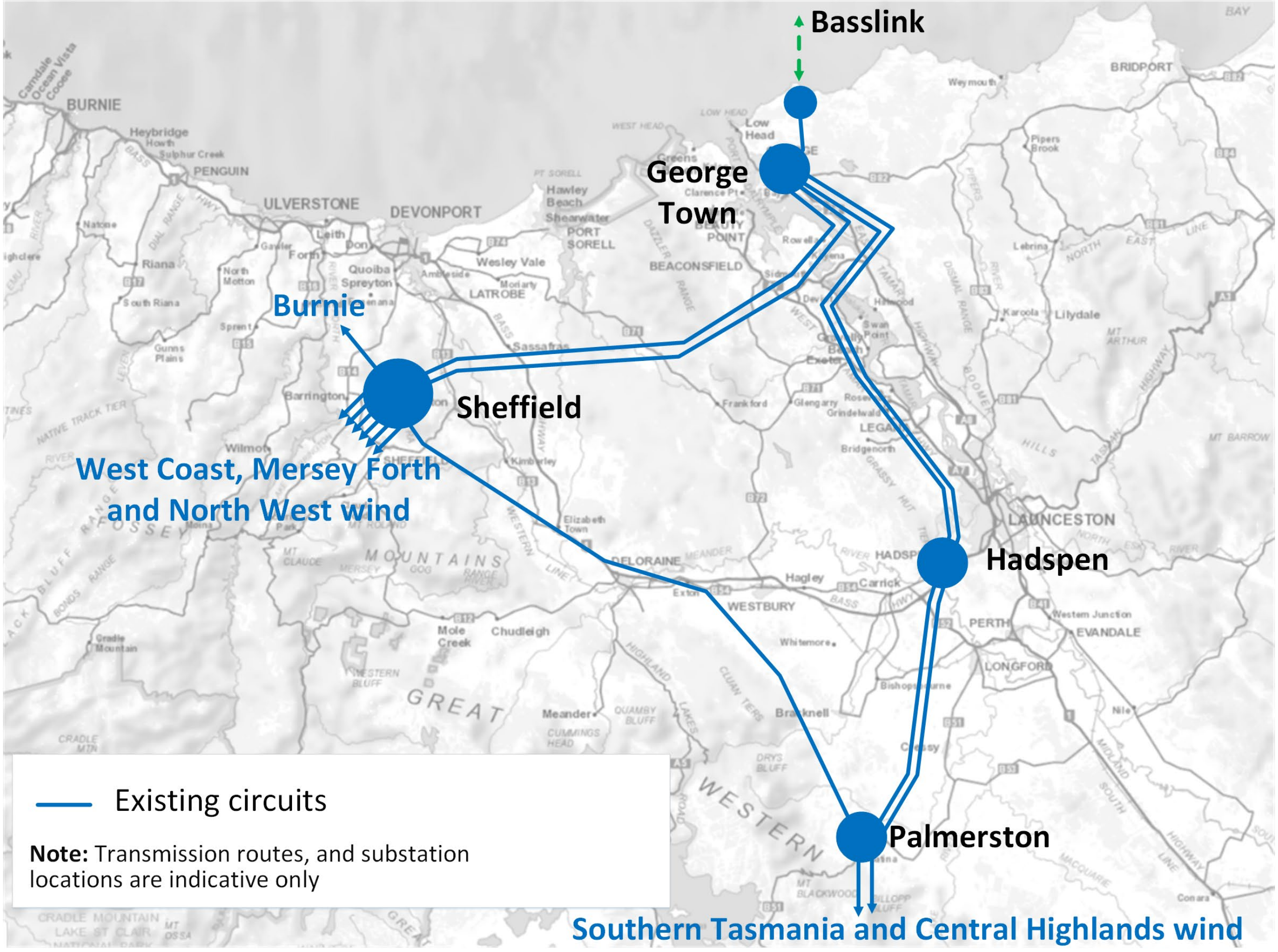

Figure 2-1 The existing 220 kV network supply to George Town Substation

Table 2-1 Transmission circuit parameters

Transmission element	Conductor type, design temperature (°C) and year of construction	Length (km)	Unconstrained Circuit rating Winter/Summer (MVA)
Sheffield–George Town 220 kV double circuit line	Ortolan - 75°C, 1968	68.0	421/357
Palmerston–Sheffield 220 kV single circuit line	Goat - 65°C, 1957	78.8	298/239
Palmerston–Hadspen 220 kV double circuit line	Goat - 75°C, 1961	33.6	333/282
Hadspen–George Town 220 kV double circuit line	Goat (49.6 km), Tern (2.1 km) - 90°C, 1961	51.7	376/334

3 Overview of the George Town contingent projects

The studies conducted by TasNetworks indicate that the existing network has very marginal capacity to accommodate any new developments in George Town. Similarly significant amount of reactive support is needed if any new loads are connected in George Town. The existing substation has limited space available to accommodate any new developments and connecting to the existing substation will increase the customer reliability and network security risk significantly. The list of contingent projects identified to address those limitations and indicative costs in 2021-22 $ are given in Table 3-1.

Table 3-1 List of contingent projects

Project	Description	Indicative cost ($m)
George Town Network Upgrade	To avoid non-compliance with the ESI regulations, an additional 210 MW load will require: • rearrangement of the existing George Town Substation and the construction of a new substation • installation of additional reactive support in George Town	119
Palmerston to Sheffield Network Upgrade	This project is proposed to address the same non-compliance following 210 MW of new load at George Town. The contingent project will be triggered if required to accommodate hydrogen loads at George Town prior the commissioning of stage 1 Marinus Link.	212
George Town Reactive Support	Following 350 MW of new load at George Town, stability constraints will begin to emerge. This project is needed to avoid constraining supply to George Town.	80
Sheffield to George Town Network Upgrade	Following further load at George Town, non-compliance with customer reliability and network capacity constraint will arise. This project is identified as a next feasible option to address the non-compliance and capacity constraint.	166

These contingent projects were tested against non-compliance issues and market benefits analysis where necessary.

3.1 Compliance requirements at George Town Substation

The *Electricity Supply Industry (Network Planning Requirements) Regulations 2018* (ESI regulations)[3] provides the customer reliability levels to be considered in planning the network. As per 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. Furthermore, the unserved energy to load that is interrupted by a single asset failure is not to be capable of exceeding 3000 MWh at any time. A single asset failure means one single incident (other than a credible contingency event) that results in the failure of one single asset to perform its intended function. In this analysis, transformer or double circuit tower line failure is applied as necessary.

[3] https://www.legislation.tas.gov.au/view/html/inforce/current/sr-2018-002#GS5@EN

4 Palmerston–Sheffield Network Upgrade

Technical studies show that supply capacity to George Town is limited due to network capacity and voltage instability at George Town due to a double circuit 220 kV line failure supplying to George Town. The Palmerston–Sheffield corridor is the weakest link in Palmerston–Sheffield–George Town–Hadspen loop. The Palmerston–Sheffield corridor has a single circuit line and it is to be replaced with a higher capacity double circuit line under Marinus Stage 1 (i.e., 2029). The cost of bringing forward the Palmerston–Sheffield augmentation by three years is $31m and would help improve the supply capacity to George Town. TasNetworks considers bring forward this augmentation as a feasible solution to facilitate new load developments in George Town.

4.1 Non-compliance with ESI regulations

Large-scale load increase at George Town Substation will mean TasNetworks will not meet its minimum network performance requirements (ESI requirements) at George Town Substation.

The ESI regulations are Tasmanian legislation which define jurisdictional reliability requirements for the transmission network in Tasmania. The ESI regulations state minimum network performance requirements which must be met for credible contingencies and defined non-credible contingencies (termed single asset failures). Regulation 5.(1)(a)(iii) states that:

> *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*

TasNetworks adopts the Australian Energy Market Operator (**AEMO**) definition of a black system from its Power System Security Guidelines.[4] The guidelines define a black system in a region as loss of more than 60% of predicted regional load, following a major power system emergency, affecting one or more power stations.

George Town Substation load was always below 60% of the Tasmanian regional load in 2022 (maximum George Town Substation load is 51%). With the addition of 210 MW flat load to the George Town Substation, the maximum percentage of George Town load reaches 60%. At this point, the loss of all load connected to George Town Substation becomes a system black event—which does not meet the minimum performance requirements of the ESI regulations. As the ESI regulations are deterministic reliability requirements, an additional 210 MW load will require reliability corrective action to ensure the transmission network meets the ESI regulations minimum network performance requirements.

Analysis shows that the loss of one of two 220 kV double circuit lines supplying George Town (i.e., Sheffield—George Town and Hadspen—George Town) can lead to non-compliance with the ESI regulation of system black event. The proposed Palmerston–Sheffield augmentation helps to address the non-compliance.

The trigger level for this augmentation is 210 MW of extra load connecting near George Town. Establishing a strong transmission link between Palmerston and Sheffield maintains supply to George Town when Hadspen–George Town or Sheffield–George Town double circuit lines are out of service.

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[4] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf

This system black event can occur only if the system is unstable after a fault and double circuit isolation. If the system remains stable, the other two circuits and Basslink can supply a significant load at George Town instantaneously or the total load subjected to the pre-fault operating condition. Therefore, the system black issue is to be evaluated with system instability limits. System studies show that instability under some low fault level condition at George Town Substation are possible.

4.2 Economic evaluation of Palmerston–Sheffield augmentation

An economic analysis was conducted to evaluate the benefits of relaxing the non-compliance issue and thermal limits by Palmerston–Sheffield augmentation against do nothing (i.e., constraining the network). As this augmentation is proposed in Marinus Stage 1, the economic analysis is to evaluate the benefits of bringing forward the augmentation by three years against implementing the augmentation under Marinus Stage 1.

The benefits of the augmentation were quantified by converting the stability limits with and without the augmentation into constraint equations and conducting market simulation studies with stability and thermal constraints. Market simulations were conducted using the 2022 ISP model (Plexos), which has only one node for Tasmania. The model was modified to represent Tasmania as a four node region with introducing additional three nodes to represent Palmerston–Sheffield–George Town–Hadspen loop and splitting Tasmanian generation and loads into these four nodes. The outcome of the market simulation studies was used in the economic analysis.

4.2.1 Constraint equations of the stability limits

Stability limits are subjected to network flows and other variables of the network. Two sets of constraint equations were developed to capture the stability limits. These are for two cut sets: flow injecting to Sheffield to the rest of the network through Sheffield–George Town and Sheffield–Palmerston corridors (Cut Set A), and flow injecting from south to the rest of the network through Hadspen–George Town and Palmerston–Sheffield corridors (Cut Set B). These cut sets and the positive direction of flow in these cut sets are shown in Figure 4-1.

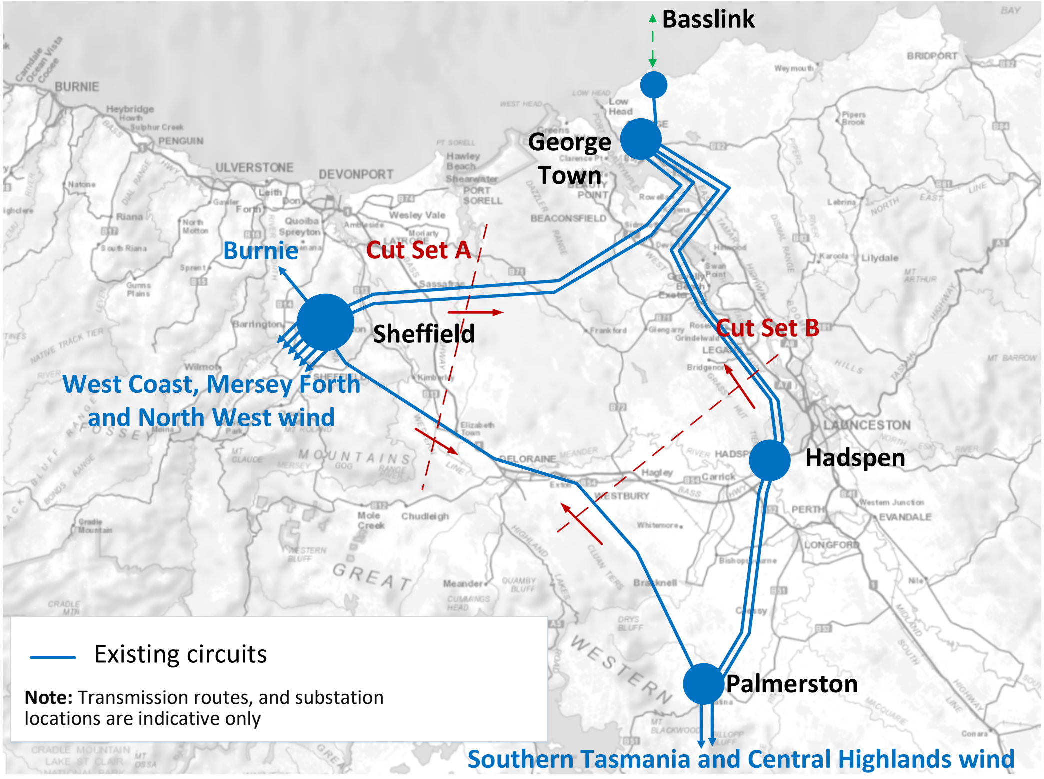

Figure 4-1 Cut sets for constraint equations

The following variables are considered to develop these constraint equations:

- Basslink flow in MW, BLexp (export from Tasmania to Victoria as positive) ;
- Fault level at George Town 220 kV bus in MVA, GTflt;
- Generation output of new generation in George Town area in MW, NEgen; and
- New load at George Town in MW, GTld.

4.2.1.1 Constraint equations prior to Palmerston–Sheffield augmentation

Two constraint equations for each cut set were developed. This is mainly due to the flow limit behaviour observed with Basslink flows. The constraint equations for Cut Set A are:

1:	***Cut Set A flow ≤ -0.515 * BLexp + 0.65 * GTflt + 0.627 * NEgen – 0.43 * GTld – 488.7***
2:	***Cut Set A flow ≤ 0.165 * BLexp + 0.563 * GTflt + 0.101 * NEgen – 0.288 * GTld – 533.9***

Similarly the constraint equations for Cut Set B are:

1:	***Cut Set B flow ≤ -0.507 * BLexp + 1.813 * GTflt + 1.032 * NEgen – 2.308 * GTld – 2512.3***
2:	***Cut Set B flow ≤ 0.327 * BLexp + 0.248 * GTflt - 0.998 * NEgen + 0.298 * GTld + 216.2***

These constraints are applicable only prior to Marinus period as Palmerston–Sheffield is a part of Marinus network developments.

4.2.1.2 Constraint equations after Palmerston–Sheffield augmentation

With Palmerston–Sheffield augmentation, the above four equations reduce to two. That means other two equations are outside the envelop of stability studies conducted.

1:	***Cut Set A flow ≤ -0.515 * BLexp + 0.65 * GTflt + 0.627 * NEgen – 0.43 * GTld – 397.9***
2:	***Cut Set B flow ≤ 0.327 * BLexp + 0.248 * GTflt - 0.998 * NEgen + 0.298 * GTld + 309.4***

In both constraints, flow limits are increased close to 100 MW. Cut Set B flow constraint was relaxed during post Marinus period to keep the export capability of Marinus link assuming Marinus has the technical capability to keep the system stable for the additional flows from Cut Set B.

4.2.2 Market simulation and economic analysis

Market simulations and economic analysis were conducted for three levels of hydrogen load at George Town (i.e., 100, 300 and 400 MW). The economic analysis was conducted to understand the breakeven hydrogen load increase to justify bringing forward Palmerston—Sheffield from 2029 to 2026.

The outcome of the economic analysis is shown in Figure 4-2. Accordingly, additional load of around 25 MW near George Town is sufficient to economically justify the bring forward cost. This is well below the non-compliance trigger level and this means addressing non-compliance issue by bringing forward the proposed augmentation is economically feasible when George Town has 210 MW additional load. The number of constrained hours during the period are given in Table 4-1. This indicates that non-compliance can occur quite often.

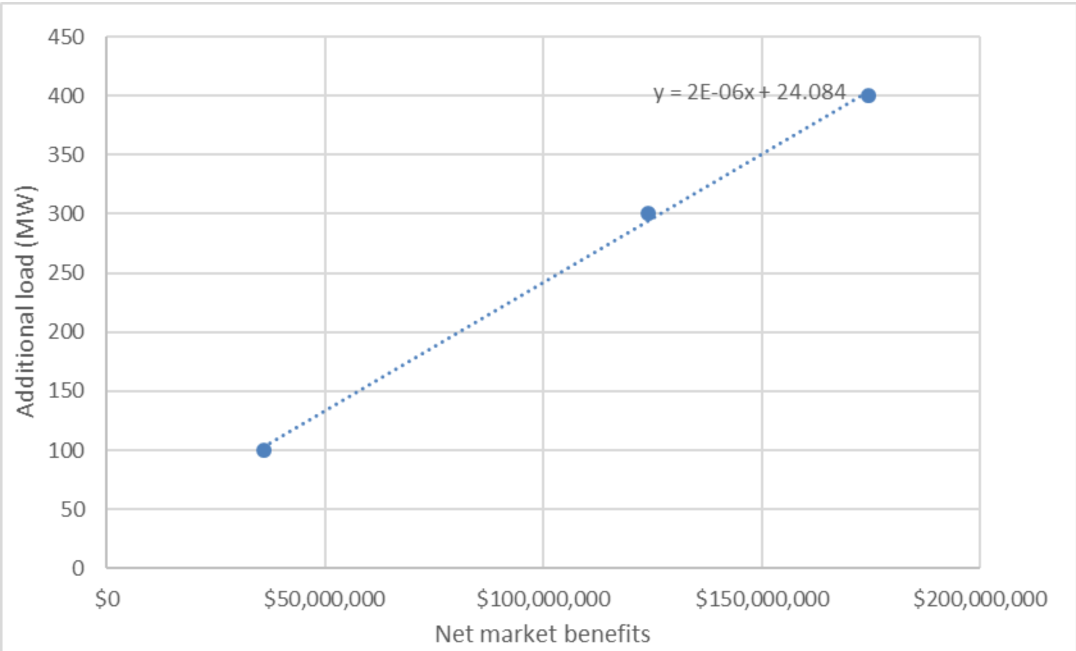

Figure 4-2 Net market benefits of bring forward Palmerston—Sheffield augmentation

Table 4-1 Cut set flow constraint binding hours prior to Palmerston--Sheffield augmentation

Year	Cut Set A injections		Cut Set B injections		Sum of cut sets A and B (% of total duration of the year)[5]	
	Additional 100 MW load	Additional 300 MW load	Additional 100 MW load	Additional 300 MW load	Additional 100 MW load	Additional 300 MW load
2026-27	3,385.50	4,035.50	3,982.00	5,360.00	84%	107%
2027-28	3,504.00	3,273.00	3,121.00	3,993.00	76%	83%
2028-29	3,830.50	4,253.00	4,293.00	5,368.50	93%	110%

4.3 Summary of the evaluation on Palmerston–Sheffield augmentation

Loss of a double circuit 220 kV transmission line supplying George Town Substation, which is a single asset failure, can lead to loss of supply to the area due to system instability. Such situation would be a system black condition, when additional load of 210 MW is connected to the existing George Town Substation. As per ESI regulation 5.(1)(a)(iii), load that is interrupted by a single asset failure is not to be capable of resulting in a black system. Connecting additional load of 210 MW can lead in to non-compliance with the above ESI regulation. This non-compliance issue can be minimised if the proposed Palmerston–Sheffield augmentation under Marinus is brought forward.

Economic analysis shows that even a small load of 25 MW increase in the area is sufficient to offset the economic cost of bringing forward the project against do nothing (i.e., constraining the network). Accordingly, addressing the non-compliance issue by bringing forward Palmerston–Sheffield augmentation is economical rather than constraining the network.

5 George Town Network Upgrade

Non-compliance with the ESI regulations on system back condition or economic triggers can arise with an additional 210 MW in George Town. This non-compliance can arise under two situations: due to a transformer fire at George Town Substation or a double circuit transmission line failure (even after Palmerston–Sheffield augmentation). The following augmentations are proposed to address the issues:

- rearrangement of the existing George Town Substation and the construction of a new substation; and
- installation of additional reactive support in George Town.

The George Town Substation augmentation is described in Section 5.1. The reactive support installation is described in Section 5.2. Combined, these augmentations comprise the George Town Network Upgrade contingent project.

[5] There is a possibility to bind more than one constraint at a time. Such simultaneous binding is not counted separately. These percentages would be lower and not above 100%, if the simultaneous binding hours are counted.

5.1 George Town Substation re-arrangement and a new substation

The existing George Town Substation has limited space for further developments, mainly due to surrounding infrastructure. Some gas facilities may increase the risk of substation operation interruptions or limit the possibilities of extending the existing substation. Figure 5-1 shows the existing George Town Substation and the surrounding infrastructure.

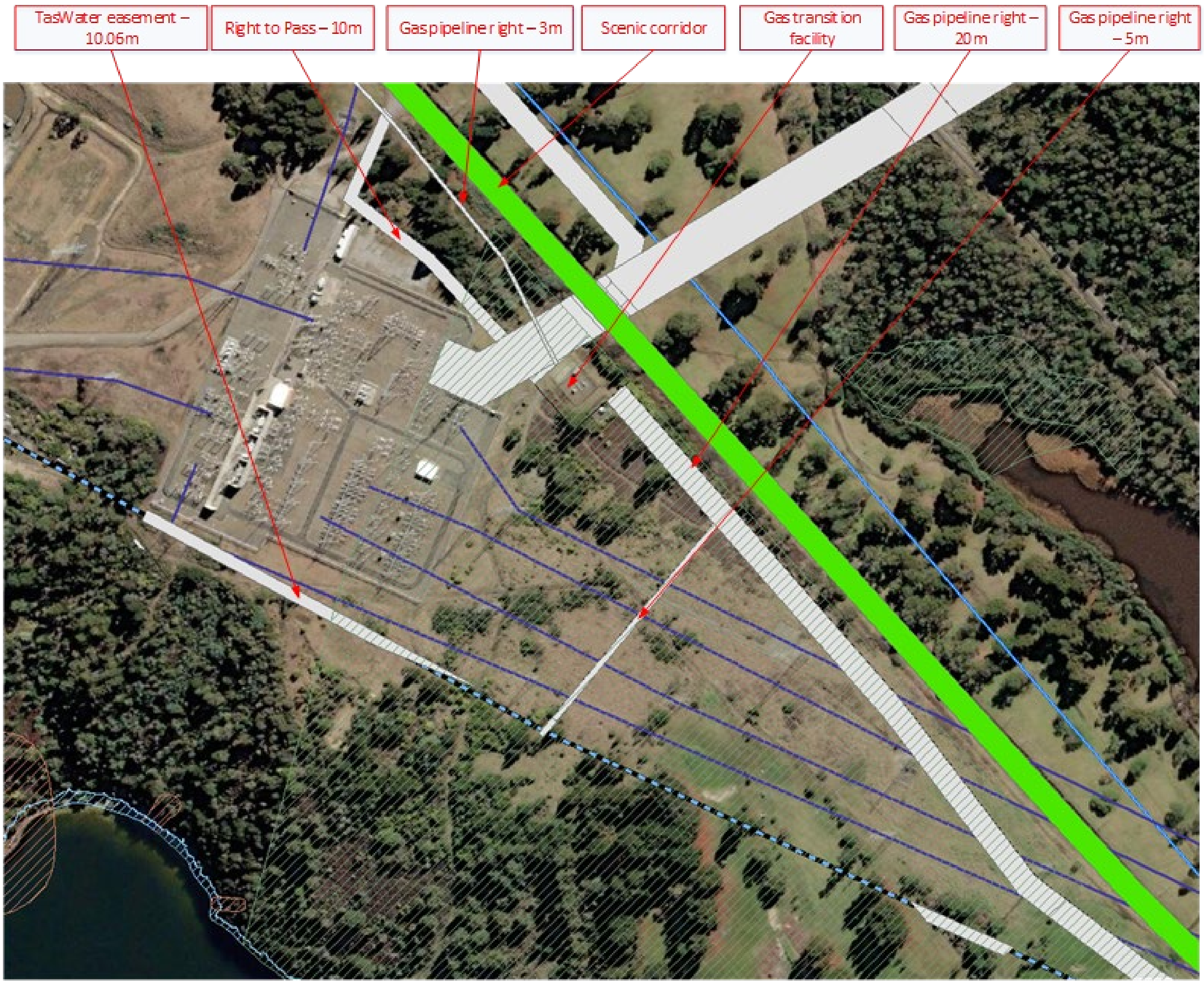

Figure 5-1 The existing George Town Substation and surrounding infrastructures

5.1.1 Non-compliance with ESI regulations

An additional load of 210 MW in George Town can lead to non-compliance with the ESI regulations system black condition described in Section 4.1.

George Town Substation has three 220/110 kV transformers and two 110/22 kV transformers next to the existing 220 kV switchyard. A fire in any of these five transformers can lead to a system black event. A transformer fire is a single credible contingency under a specific circumstance. Therefore, this situation is linked to single asset failure rather than a credible contingency.

The other non-compliance event is a 3000 MWh interruption due to an outage (i.e., 5.(1)(a)(v)). The above risk assessment indicates that outage duration for a fire at George Town Substation could be much longer than Dapto Substation outage (refer Section 5.1.2 following).

If George Town substation has a breakeven 60% limit (i.e., additional 210 MW), a 4.5 hour outage will lead to non-compliance with 3000 MWh limit. If a transformer fire distracts the supply to George Town Substation for more than 6.6 hours under the existing load, non-compliance with 3000 MWh limit can occur. One 220 kV/ 110 kV transformer has 85,500 litres of oil and other two transformers have 72,000 litres of oil each. A transformer fire can exist over long period with such a large volume of oil.

The analysis was extended to visualize risk and other reliability levels.

5.1.2 Risk associated with the existing switching station

The risk of system black associated with George Town Substation was assessed by comparing the recent transformer (330 kV/132 kV, 375 MVA) fire at Dapto Substation in New South Wales. This fire occurred on 18 June 2022. There is limited information available on this event. However, some media reports describe the situation.

As a result of the fire, a large smoke plume from the blaze affected nearby Wollongong and Unanderra, with flights at nearby Shellharbour Airport delayed[6]. The aerial distance between Dapto Substation and Shellharbour airport is around 2 km. An EnergyAustralia media statement says their Tallawarra power station went offline for around 2 hours[7]. Tallawarra power station (435 MW) is around 2.5 km from Dapto Substation and connected to rest of the network through Dapto Substation. The severity of the fire is further illustrated in Figure 5-2.

Figure 5-2 Photos of Dapto Substation fire[8]

For comparison purposes, the Dapto and George Town substation single line diagrams are shown in Figure 5-3. Dapto Substation has bus sectionalisers in 330 kV and 132 kV and transformers connected to 132 kV bus in a double breaker arrangement. In George Town Substation, only a part of the 220 kV switchyard has breaker and half arrangement and no bus sectionalisers. George Town Substation has much lower operational flexibility compared to Dapto Substation. In George Town re-arrangement, split bus arrangement, and diversity of network connections (currently both network lines are next to each other opposite to transformer diameters) are proposed.

The risk at George Town Substation is heightened by the lower physical distances between transformers and other parts of the substation compared to Dapto Substation. George Town Substation is quite compacted compared to Dapto Substation. That means there is a higher chance of fire affecting other equipment and limited access to control the fire, which could lead to higher restoration time. A comparison of George Town and Dapto substation is shown in Figure 5-4.

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[6] [Fire engulfs major substation south of Sydney, with one transformer fully alight - ABC News]
[7] [Media Statement on Transgrid's fire at Dapto substation | EnergyAustralia]
[8] [Power station fire still burning but blaze is 'contained' (9news.com.au)]

George Town Substation has firewalls for 220 kV/110 kV transformers, however these may not be sufficient to totally control the smoke, ashes and heat spreading to other equipment. In terms of the existing substation arrangement and physical distances within George Town Substation compared to Dapto Substation, the risk of affecting a fire to the rest of the substation and restoration durations would be much higher.

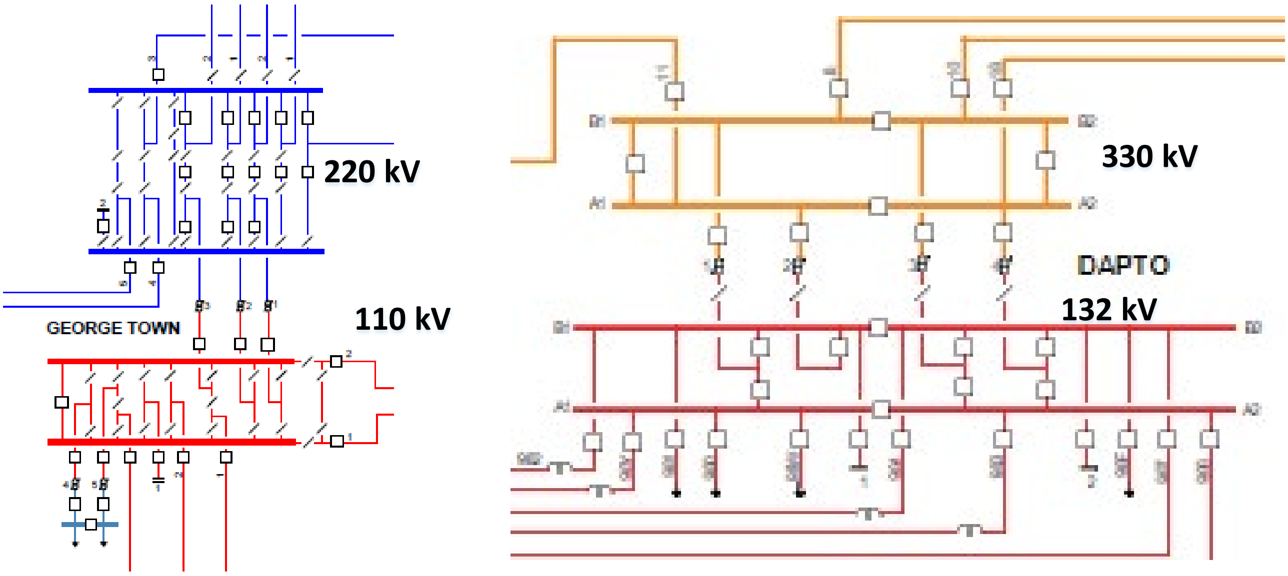

Figure 5-3 Single line diagrams of George Town and Dapto substations

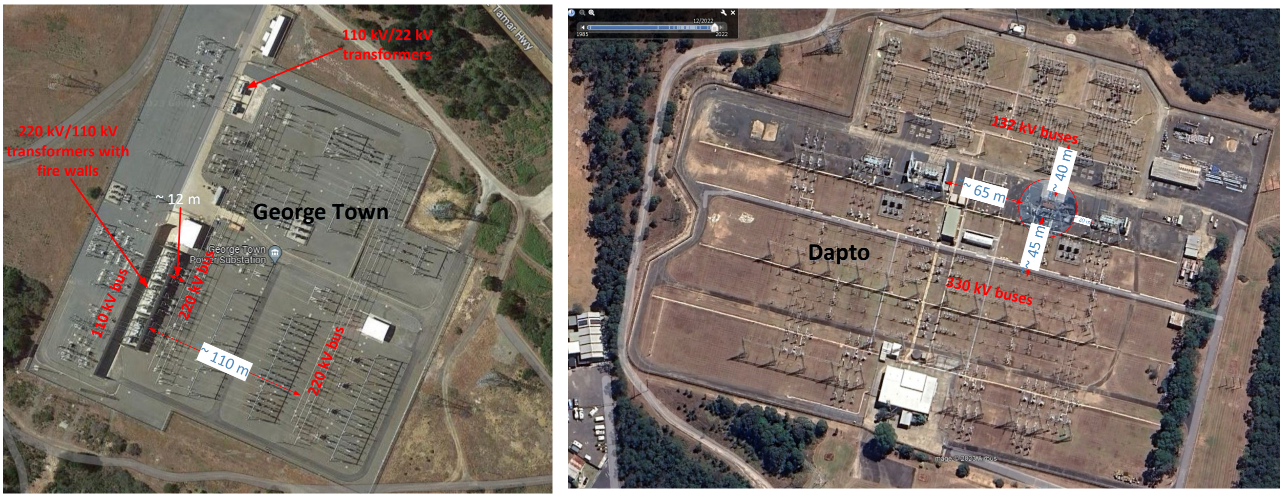

Figure 5-4 pictures of George Town and Dapto substations

The other risk of the existing substation is having only two 220 kV buses (Figure 5-3). If any bus is taken out of service and any failure occurs in the other that would lead into a total George Town Substation failure. Bus failure can occur due to breaker failure or human error especially when one bus is taken out of service.

5.1.3 Economics of re-arranging the existing substation

The identified solution to address the issues around the George Town Substation is to re-arrange the existing substation and develop a new substation to accommodate new loads. The estimated cost for re-arrangement and developing a new substation is $46m. Out of that, $23m is for re-arranging the existing substation.

An analysis was conducted assuming a transformer fire is a one in 400 transformer.year event[9]. The economic analysis was conducted for different outages time against breakeven new load to make George Town rearrangement and new substation cost economical. These results are given in Table 5-1.

Table 5-1 Economical level of new load to develop a new substation

Substation outage duration per year (minutes)	Outage duration per incident (Hours) assuming probability of transformer fire is 1 in 400 transformer.year	Breakeven new load (MW)
9	12	0 (existing load is above the breakeven level)
8	10.7	27
7	9.3	104
6	8.0	207
5	6.7	351

These results indicate that even with a small probability, the risk will offset the cost of a rearranging the existing George Town Substation. In addition to a transformer fire, a bus outage when the other bus is out of service is another possible event. The breakeven load would be much lower if all these possible outages are taken into account.

5.1.4 Available space of the existing substation and economics of developing new substation

The existing George Town Substation has a number of vacant bays, which will be used to address the reliability issues of the existing substation and to connect capacitors or dynamic reactive support. Figure 5-5 shows the existing 220 kV George Town Substation with proposed re-arrangements and some space available for new connections.

In addition to these, two diameters each can be developed in either side of the substation. TasNetworks considers it is highly unlikely that any new connections will materialise from the right hand side of the diagram. There is a narrow corridor between Tamar River and the substation but it highly unlikely to have any new developments in that area. Therefore, the bays available for the new connections are the bays on left (i.e., two additional diameters beyond the existing switchyard, the new diameter already shown in the diagram, and the bay opposite to Hadspen 2 circuit). Back to back connection of generators and loads in any diameter is not considered a feasible option (to avoid possible risk of islanding operation under some outages). Approaching these diameters from the western end is also limited due to encapsulated storage mount in that end. Accordingly, three bays are available for new connections.

High-level economic analysis was conducted to see the benefits of developing a new substation at the initial stage against connecting the initial load to the existing substation. The following assumptions were made to this analysis.

- Developing a substation closer to new connections reduces the connection cost.
- With the forecast load growth in George Town, the new substation is needed within at least 3 years to accommodate the load beyond 300 MW.

[9] Cigre B3 Technical Brochure, Guidelines for Fire Risk Management in Substations, November 2022

- Developing the vacant diameters of the existing George Town Substation is costly (need to extend the fence, relocate the existing 22 kV feeders, and may need cable connections to approach these bays due to limited access).
- Re-arranging the existing George Town Substation is needed whether the initial load is connected to the existing substation or in a new substation (economics of re-arranging George Town Substation is undertaken separately and given in Section 5.1.3).

The additional cost of connecting these three bays at George Town Substation were compared against bringing forward cost of a new substation. Out of $46m, $23m is to establish new substation and the rest is to re-arrange the existing substation. The bring forward cost of $23m investment by 3 years is around $3.5m compared against the additional cost to develop two or three bays, which are around $3.5m and $4.9m respectively. Two bay development is breakeven with establishing a new substation in the first instance. As per the frequency operating standards[10], if the load is above 144 MW, a double circuit line is needed unless automatic load shedding or other arrangement is established. The cost comparison indicates that developing a new substation is economical if the load is above 144 MW even without considering avoided risk due to keep all loads at a single location.

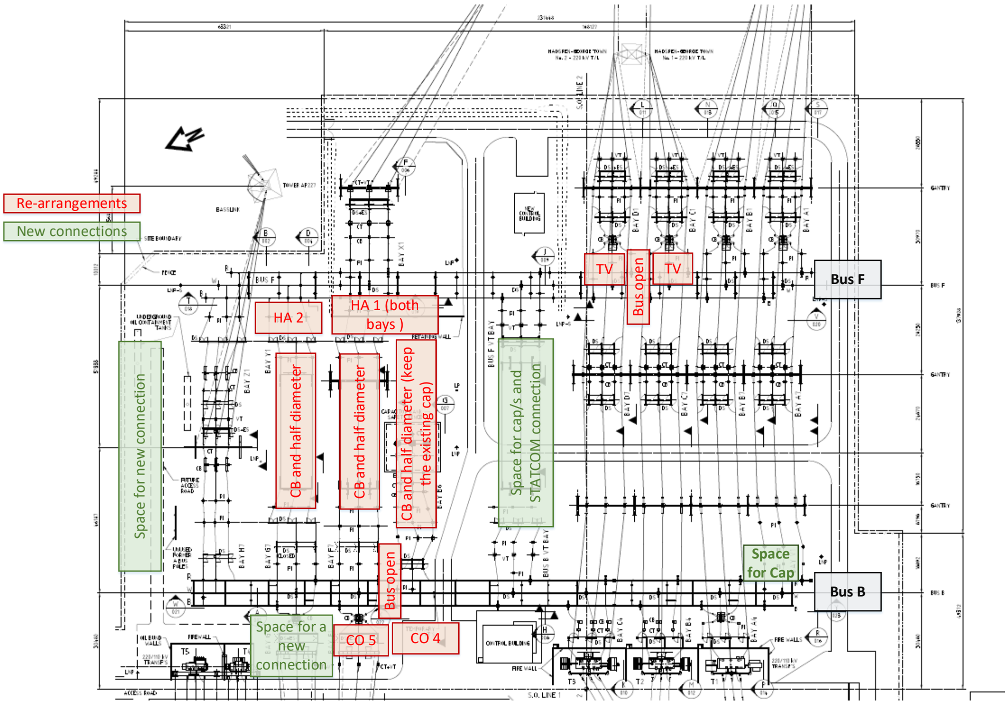

Figure 5-5 Map of the George Town Substation with proposed augmentations

[10] https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

5.1.5 Summary of the evaluation on new substation development and George Town Substation re-arrangement

This evaluation is to identify a trigger level with the consideration of possible non-compliance issues and economic aspects. A transformer fire at George Town Substation can lead in to loss of the whole substation. Such situation would be a system black condition as per AEMO definition of system black, when additional load of 210 MW is connected to the existing George Town Substation. As per ESI regulations, load that is interrupted by a single asset failure is not to be capable of resulting in a black system. Connecting additional load of 210 MW can lead to non-compliance with the above ESI regulation. The proposed rearrangements and George Town Substation and the new substation helps to avoid this non-compliance issue if additional load of 210 MW is developed to George Town.

This situation can lead into non-compliance with ESI regulation, 5.(1)(a)(v). ESI regulation, 5.(1)(a)(v), is that the unserved energy to load that is interrupted by a single asset failure is not to be capable of exceeding 3000 MWh at any time. Non-compliance with ESI regulation, 5.(1)(a)(v) could occur in for a significant load interruption for a long period due to a transformer fire.

Economic analysis also shows that re-arranging the existing substation and establishing a new substation would be economical if the additional load at George Town reaches to 210 MW.

5.2 Dynamic reactive support at George Town

Even after the Palmerston–Sheffield augmentation, the non-compliance issue due to a 220 kV double circuit line failure can still exist at higher level of load under different system conditions. The identified next solution is to install dynamic reactive support to keep the system stable after the fault. The trigger for the dynamic reactive support or an alternative solution remains as 210 MW of additional load. Market simulation and economic analysis were conducted to evaluate the economic impact of dynamic reactive support against do nothing (i.e., constraining the network).

5.2.1 Market simulation and economic analysis

The impact of the proposed dynamic reactive support on post Palmerston–Sheffield augmentation constraints were evaluated to undertake market simulation studies. The studies show that the right hand side of Cut Set A constraint improves by 643 MW and the right hand side of Cut Set B constraint improves by 126 MW the proposed dynamic reactive support. Accordingly, new constraints are as follows:

1: Cut Set A flow ≤ -0.515 * BLexp + 0.65 * GTflt + 0.627 * NEgen – 0.43 * GTld + 245.6

2: Cut Set B flow ≤ 0.327 * BLexp + 0.248 * GTflt - 0.998 * NEgen + 0.298 * GTld + 435.2

Similar to the Palmerston–Sheffield augmentation case, the Cut Set B flow constraint was relaxed during the post Marinus period to keep the export capability of Marinus link and market simulations were conducted for 100, 300 and 400 MW of additional load. The economic analysis was conducted for the cost of dynamic reactive support against the incremental benefits from the dynamic reactive support after implementation of Palmerston–Sheffield augmentation.

Additional load against net market benefits are shown in Figure 5-6. The results show that even the existing load is sufficient to justify the investment in additional reactive support when the whole George Town area load interruption is avoided due to double circuit failure. This is well below the non-compliance trigger level (i.e., additional load of 210 MW) and means addressing the non-compliance issue by installing dynamic reactive support is economical. The number of constrained hours after Palmerston–Sheffield augmentation are given in Table 5-2. The constraints are to be bound around 10% of the time meaning it is highly likely TasNetworks will be non-compliant with the system black rules in the ESI regulations.

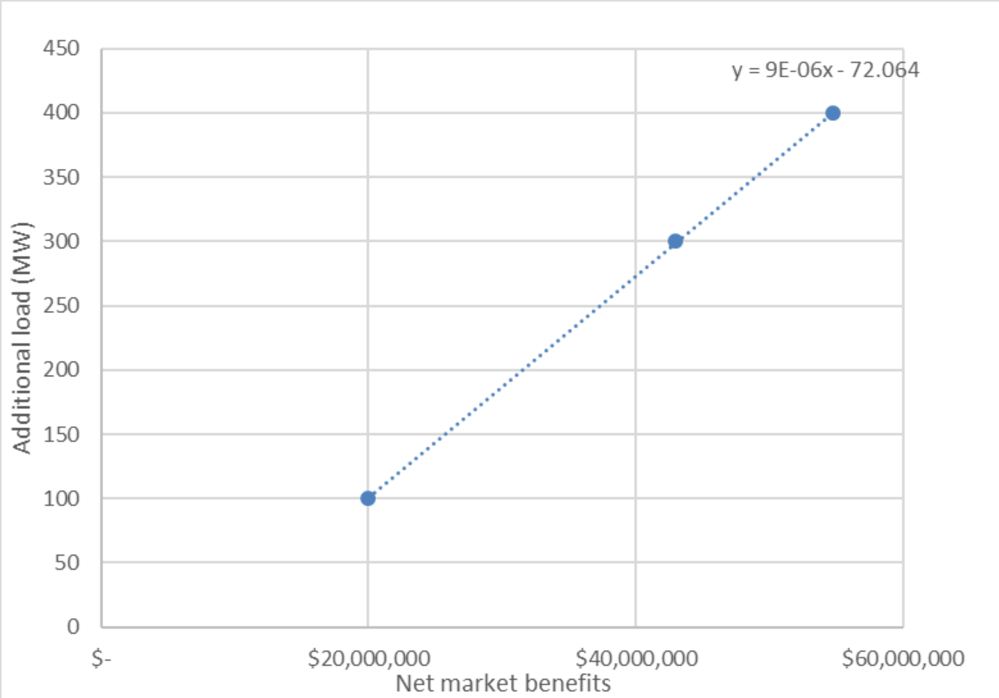

Figure 5-6 Net market benefits of the proposed dynamic reactive support

An analysis of post dynamic reactive power market simulation results indicated that further non-compliance with the system black limits is unlikely to happen before 2031 if George Town new load is below 300 MW (constrained hours shown in the market simulations are very low).

Table 5-2 Cut set flow constraint binding hours prior to dynamic reactive support after Palmerston--Sheffield augmentation

Year	Cut Set A injections		Cut Set B injections		Sum of cut sets A and B (% of total duration of the year)[11]	
	Additional 100 MW load	Additional 300 MW load	Additional 100 MW load	Additional 300 MW load	Additional 100 MW load	Additional 300 MW load
2026-27	570.5	648	44	243	7%	10%
2027-28	1005	1255	50.5	246	12%	17%
2028-29	931	819	144	366.5	12%	14%
2029-30	1288.5	1447.5	0	0	15%	17%
2030-31	1433	1618.5	0	0	16%	18%
2031-32	2,705.50	3,095.00	0	0	31%	35%
2023-33	1,379.50	1,669.50	0	0	16%	19%
2033-34	1,876.50	2,121.50	0	0	21%	24%
2034-35	1,410.50	1,701.50	0	0	16%	19%

[11] There is a possibility to bind more than one constraint at a time. Such simultaneous binding is not counted separately. These percentages would be lower and not above 100%, if the simultaneous binding hours are counted.

5.2.2 Summary of the evaluation on dynamic reactive support at George Town

Installation of dynamic reactive support at George Town is considered as the next solution after Palmerston–Sheffield double circuit line to address the non-compliance ESI regulation 5.(1)(a)(iii) due to a failure of a double circuit 220 kV transmission line supplying to George Town. The non-compliance with the above ESI regulation can exist after connecting 210 MW new load as per AEMO definition on black system.

Economic analysis shows that even the existing system is sufficient to offset the economic cost of dynamic reactive support against cost of constraining the network. Accordingly, addressing the non-compliance issue by installing dynamic reactive support is economical when the additional load at George Town reaches to 210 MW.

6 Sheffield–George Town Network Upgrade

The analysis was continued to understand the thermal limitations as well as system instability due to double circuit failure (i.e., system black event in George Town) as expected load growth is quite significant. The proposed next augmentation is to install an additional new double circuit 220 kV line between Sheffield and George Town. If additional load connected to George Town in excess of 210 MW and system instability occurs, it is a non-compliance with the ESI regulation 5.(1)(a)(iii) (i.e., system black due to single asset failure). Market simulations and economic analysis were conducted with the consideration of thermal and stability limits to understand the trigger for the augmentation against constraining the network.

The proposed Sheffield–George Town 220 kV twin Sulphur double circuit line has 2000 MVA non-firm capacity available at 15°C ambient temperature (winter rating). Therefore, total capacity of Sheffield–George Town corridor at 15°C ambient temperature would be 2842 MVA. This is well above the George Town total load and Basslink export capacity (i.e., less than 2000 MW even with 1000 MW new hydrogen load). In this analysis, series reactors are considered in Palmerston–Hadspen–George Town corridor to improve the utilization of the Sheffield–George Town corridor. The cost of the series reactors (i.e., $15.6m) are included into the economic analysis and these reactors would help to delay potential augmentation to the Palmerston–Hadspen–George Town corridor.

6.1.1 Market simulation and economic analysis

The possible improvements in the constraint equations on power injection through cut sets A and B are evaluated. The Sheffield–George Town new 220 kV double circuit line improves the limits on cut sets A and B flows by 617 MW and 74 MW respectively. The revised constraints are:

1: Cut Set A flow ≤ -0.515 * BLexp + 0.65 * GTflt + 0.627 * NEgen – 0.43 * GTld + 862.3

2: Cut Set B flow ≤ 0.327 * BLexp + 0.248 * GTflt - 0.998 * NEgen + 0.298 * GTld + 509.7

Market simulation and economic analysis were conducted for 600, 800 and 1000 MW additional loads at George Town. The economic analysis evaluated the costs of the Sheffield–George Town double circuit 220 kV line and series reactors against the incremental market benefit of the line augmentation. The net market benefits of the proposed line against additional load in the George Town area are shown in Figure 6-1. Accordingly, the breakeven load to make the Sheffield–George Town new double circuit line to be economical is 712 MW new load.

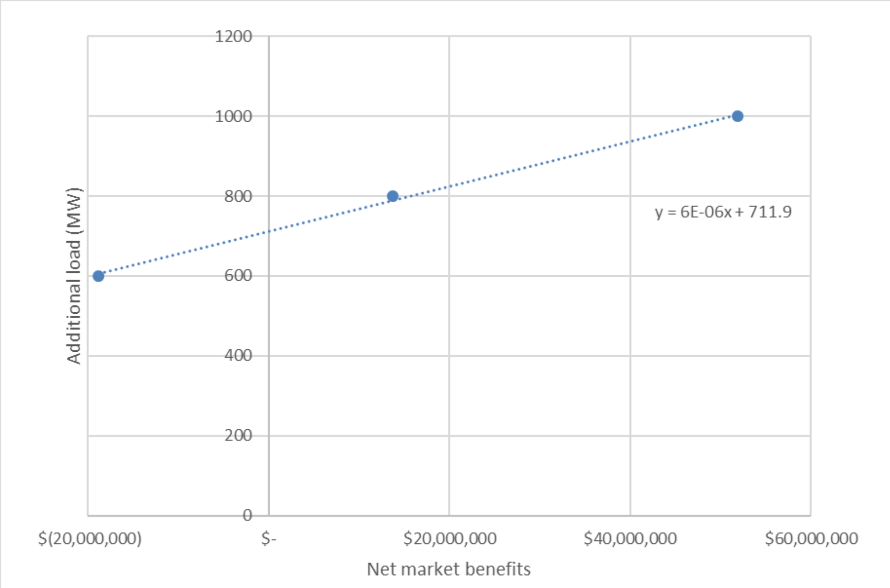

Figure 6-1 Net market benefits of the proposed Sheffield—George Town double circuit 220 kV line

Table 6-1 shows the number of constrained hours with 600 and 1000 MW additional load connected to the George Town substation. The constrained hours are quite low with 600 MW additional load and it has gone up significantly when additional load increases to 1000 MW. This indicates the need of the proposed augmentation to reduce the constraining hours with load increase.

The market simulation studies indicate that if the load increases by 600 MW, with or without Sheffield–George Town augmentation, around 120 MW of wind in North East Renewable Energy Zone (REZ) is needed in the initial years. When load increases to 1000 MW, 120 and 350 MW of new wind in North East REZ is needed with and without the Sheffield—George Town augmentation respectively.

Table 6-1 Cut set flow constraint binding hours after dynamic reactive support at George Town area

Year	Cut Set A injections		Cut Set B injections		Sum of cut sets A and B (% of total duration of the year)[12]	
	Additional 600 MW load	Additional 1000 MW load	Additional 600 MW load	Additional 1000 MW load	Additional 600 MW load	Additional 1000 MW load
2026-27	107	18.5	86	953	2%	11%
2027-28	29	288	41.5	1,018	1%	15%
2028-29	91	311.5	100	827	2%	13%
2029-30	605	928	0	0	7%	11%
2030-31	628	805.5	0	0	7%	9%
2031-32	1,242.50	1,831.50	0	0	14%	21%
2023-33	888.50	1,217.50	0	0	10%	14%
2033-34	1,307.00	1,619.50	0	0	15%	18%

[12] There is a possibility to bind more than one constraint at a time. Such simultaneous binding is not counted separately. These percentages would be lower, if the simultaneous binding hours are counted.

Year	Cut Set A injections		Cut Set B injections		Sum of cut sets A and B (% of total duration of the year)[12]	
	Additional 600 MW load	Additional 1000 MW load	Additional 600 MW load	Additional 1000 MW load	Additional 600 MW load	Additional 1000 MW load
2034-35	1,078.50	1,275.50	0	0	12%	15%

7 George Town Reactive Support

The reactive power requirement at George Town is expected to increase continuously as load increases. This has been identified in the technical studies conducted. It is assumed that the reactive power requirements linearly increase with the new load.

ISP market modelling incorporated the new hydrogen loads as an energy purchaser (i.e., hydrogen loads are price responsive). The recent market simulation studies conducted using the ISP model shows that significant variations in the load from one load block to another load block. That means rapid changes in active power requirements can be observed in the future system when the loads are price responsive. If the active power requirements vary rapidly, the reactive power demand also varies accordingly to maintain the voltage. Therefore, dynamic reactive support is needed to accommodate new loads providing rapid changes in reactive power demand.

ISP data shows that the expected capacity factor for these hydrogen loads are around 75%. Therefore, reactive support requirements identified in the technical studies are considered for the average hydrogen load and reactive power requirement to connected load is calculated accordingly. The reactive support requirement against connected hydrogen load at George Town are shown in Figure 7-1.

The George Town Network Upgrade is expected to install 300 MVAr of capacity, which is sufficient for 350 MW of new load. Therefore, the technical trigger for George Town Reactive Support is 350 MW of new load at George Town.

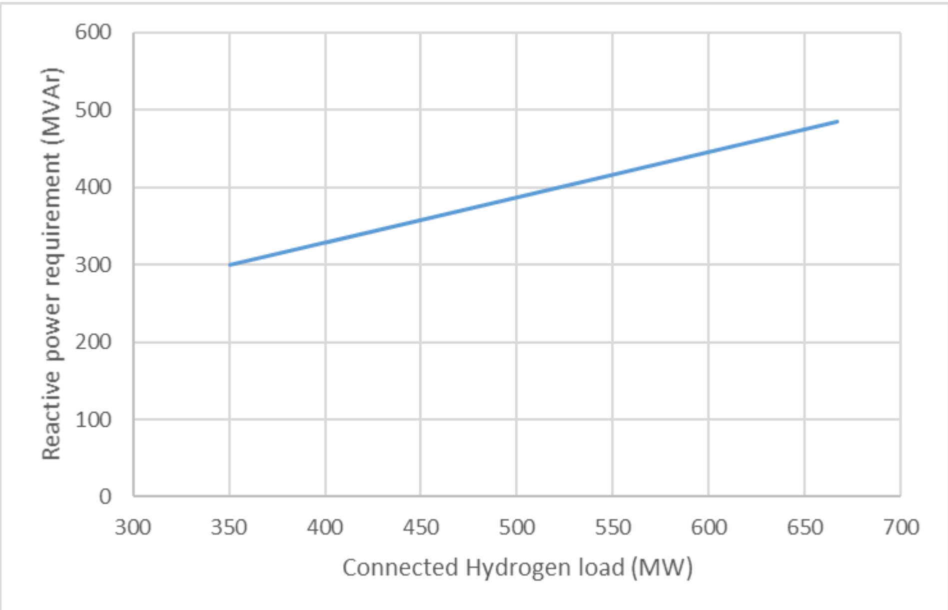

Figure 7-1 Reactive power requirement vs hydrogen load at George Town

8 Waddamana to Palmerston Transfer Capability Upgrade

The final contingent project proposed in our Original Proposal was the Waddamana to Palmerston Transfer Capability Upgrade. This project will upgrade the transmission corridor between Waddamana and Palmerston substation to maintain power flows within thermal and/or stability limits following connection of new generation in central or southern Tasmania.

The primary trigger for this project (alongside the successful completion of RIT-T and TasNetworks' board commitment to proceeding with the project, common to all proposed contingent projects) given in the Original Proposal was:

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*

We propose to amend the trigger to provide a MW-level of new generation commitment required before generation constraints will occur. This will ensure the trigger is objectively verifiable.

Further, the Original Proposal focussed on the outcomes of the AEMO 2022 Integrated System Plan (**ISP**) as providing the need for this project. This document identifies the need and probability of occurrence based on activity directly between TasNetworks and new generation proponents.

8.1 Central Highlands and southern Tasmania network

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. Figure 8-1 presents the existing transmission network in Central Highlands and southern Tasmania.

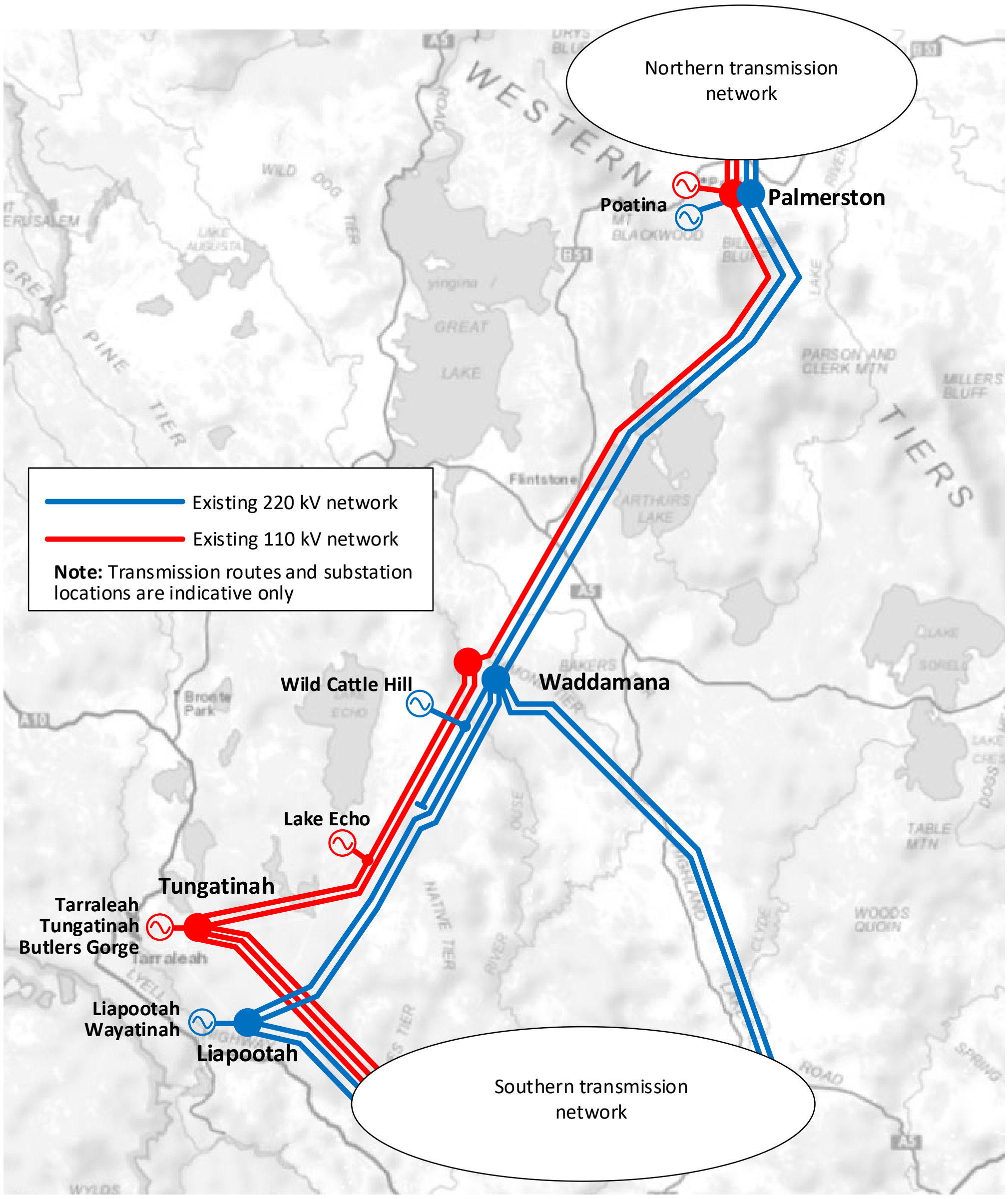

Figure 8-1 Central Highlands and southern Tasmania network

The Central Highlands and portion of the southern transmission network area forms the Central Highlands renewable energy zone (**REZ**). The Central Highlands REZ has excellent wind resources, which are the highest of all REZs across the National Electricity Market.[13] New large-scale wind generation is expected to connect to the 220 kV transmission network surrounding Waddamana Substation and to the transmission lines south.

Given the 'closed' transmission system south of Waddamana Substation, flow through the Waddamana–Palmerston transmission corridor is the net of the generation-load balance south of Waddamana Substation. Therefore adding new generation into the area will result in a net increase of power flow northwards (towards Palmerston Substation) through the Waddamana–Palmerston transmission corridor.

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[13] 2023 IASR Assumptions Workbook (Capacity Factors tab) AEMO, published 28 July 2023 https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

8.2 Corridor capability

The Waddamana–Palmerston 220 kV transmission line section has summer/winter static rating of 420/501 MVA per circuit. With dynamic ratings (utilising real-time temperature and wind speed data) the transmission line rating exceeds 570 MVA per circuit for 98% of the time (up to 800 MVA for 2% of the time). TasNetworks operates the transmission network with dynamic ratings, and that is the basis to assess the corridor capability in this analysis.[14]

Existing flow through the Waddamana–Palmerston 220 kV transmission line is predominantly north-to-south, and ranges between ±400 MVA in both southwards and northwards direction. The addition of new generation in the Central Highlands REZ will decrease the amount of north-to-south flow, and increase the amount of south-to-north flow. There will become a point where the amount of new generation means south-to-north flow exceeds the capability of the Waddamana–Palmerston transmission corridor.

8.3 Identification of trigger

Generally, the primary trigger to upgrade the Waddamana to Palmerston transfer capability is the amount of new generation that can be accommodated in the Central Highlands REZ until the existing corridor capability is reached.

This analysis was undertaken through the following the steps. The analysis was undertaken on half-hourly data from September 2020 (following Wild Cattle Hill Wind Farm commencing full operation) to June 2023, excluding an eight-week period between October to December 2022 during an extended double-circuit outage of the Waddamana–Palmerston 220 kV transmission line.[15]

1. identify the existing available network capacity in the Waddamana–Palmerston 220 kV transmission line, being the difference between the transmission line firm dynamic rating and power flow through the transmission line (flow towards Palmerston Substation being ‘positive’ and flow southwards towards Waddamana Substation being ‘negative’);
2. consider a new generation source at Waddamana Substation, representing new wind generation development in the Central Highlands REZ;
3. develop generation profile for new generation source to match that of Wild Cattle Hill Wind Farm (ie based on instantaneous capacity factor), new generation source will add to northward flow (towards Palmerston Substation) on the Waddamana–Palmerston 220 kV transmission line (or offset southward flow); and
4. increase the capacity of the new generation source until available network capacity in the Waddamana–Palmerston 220 kV transmission line is exhausted (resulting in a constraint on generation) for 2% of the tine (meaning 98% of the time remains unconstrained).

When the installed capacity of new (wind) generation source at Waddamana Substation is 660 MW, the available network capacity of the Waddamana–Palmerston 220 kV transmission line is exhausted. This is the technical trigger for Waddamana to Palmerston transfer capability upgrade.

[14] Note that the existing transmission line rating is constrained by terminal equipment limitations at Palmerston Substation. We proposed a NCIPAP project as part of our Original Proposal to relieve this constraint. The analysis for Waddamana to Palmerston transfer capability upgrade is undertaken on the basis the terminal equipment limitations have been relieved.

[15] Trip of Liapootah–Palmerston–Waddamana No 1 and No 2 22 kV lines, Power system operating incident reports, 30 June 2023 https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports

8.4 Probability to occur in the regulatory control period

This section demonstrates the probability of new generation in the Central Highlands REZ, sufficient to meet the proposed trigger. There are three levels of justification that provide—while not certain—it is probable that more than 660 MW of new generation will become committed (or connect) within the Central Highlands REZ in the 2024–29 regulatory control period.

8.4.1 Publicly-announced new generation proposals

There are currently six publicly-announced wind farm proposals in the Central Highlands REZ, with capacity totalling more than 1,700 MW. These proposals are presented in Table 8-1.[16]

Table 8-1 Central Highlands REZ publicly-announced proposals

Wind farm	Capacity (MW)
Bashan	460
Cellars Hill	400
Derwent Valley	150
Hollow Tree	420
St Patricks Plains	291
Triabunna	30
Total	**1,751**

Our Original Proposal[17] stated "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." Since then those other projects have become publicly announced, with total capacity of all announced-projects now 1,751 MW. All proposals have lodged connection enquiry with TasNetworks under the NER. St Patricks Plains Wind Farm is significantly underway through its project development phase.[18] Other new wind generation resource may be identified also.

It is probable that 660 MW of the 1,751 MW publicly-announced new wind generation projects in the Central Highlands REZ will be become committed (or connect) in the 2024–29 regulatory control period.

8.4.2 Tasmanian Renewable Energy Target

The Tasmanian Renewable Energy Target (**TRET**) is Tasmanian legislation to provide 21,000 GWh of annual renewable energy production by 2040, with an interim target of 15,750 GWh of annual renewable energy production by 2030.[19] The 2040 target equates to 200% of Tasmania's energy requirement from 2020 of 10,500 GWh.

[16] NEM Generation Information October 2023 https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
[17] TasNetworks-Combined Proposal Attachment 7 – Contingent projects-Jan 23, Section 7.5.2.7 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2024%E2%80%9329/proposal
[18] https://arkenergy.com.au/wind/st-patricks-plains/
[19] https://www.stategrowth.tas.gov.au/recfit/renewables/tasmanian_renewable_energy_target

To meet the interim target, 5,250 GWh of renewable energy will be required from new generation sources (with existing sources providing 10,500 GWh). With an assumed capacity factor of 40%, the interim target will require 1,500 MW of new wind generation by 2030 in Tasmania.

It is probable that at least 660 MW of the 1,500 MW target will become committed (or connect) in the 2024–29 regulatory control period in the Central Highlands REZ, due to the existing network capacity (which is limited in other Tasmanian REZs) and the excellent wind resource in the Central Highlands REZ.

8.4.3 Integrated System Plan

As stated in the Original Proposal, the ISP forecasts new wind generation in excess of 1,000 MW installed capacity in the Central Highlands REZ by 2030.[20] This is built to meet the interim TRET, with excellent wind resource of Central Highlands REZ, to help facilitate the optimal development pathway of the NEM's transition to a power system supported by renewable energy, storage, and transmission.

It is probable that at least 660 MW of the forecast 1,000 MW of new wind generation requirement in the Central Highlands REZ will be become committed (or connect) in the 2024–29 regulatory control period.

8.5 Revised triggers

The revised triggers from our Original Proposal for the Waddamana to Palmerston transfer capability upgrade are as set out below. In addition to the change to trigger 1, we have also made minor wording change to trigger 2.

1. commitment of at least 660 MW of new generation in the Central Highlands REZ;
2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates upgrading the transfer capability of the Waddamana–Palmerston transmission corridor 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.

8.6 Indicative solution and cost

The indicative solution and cost for the Waddamana to Palmerston transfer capability upgrade remain as per the Original Proposal. That is, the indicative solution proposed 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. The project is estimated to cost $113 million.

9 North West Network Upgrade

There is one additional contingent project proposed in the Revised Proposal that was not included in the Original Proposal, or Draft Decision from the AER. This proposed contingent project is the North West Network Upgrade.

[20] Section A3.6.5 Tasmania, T3 – Central Highlands, Appendix A3 Renewable Energy Zones, 30 June 2022 https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

In September 2023, the Tasmanian and Australian governments announced a new deal for Marinus Link to take the project forward. This included a focus to deliver one cable in the first instance, with the second cable to be considered as part of the final investment decision making of the project.[21] Following this, in November 2023, TasNetworks announced a revised scope for the North West Transmission Developments project to support Marinus Link.[22] The project timing and staging has been revised to ensure the efficient and cost-effective delivery of the transmission network required for the first Marinus Link cable, while maintaining flexibility to deliver the network needed for a second Marinus Link cable.

The revised staging for the North West Transmission Developments is presented in Figure 9-1. The scope for Stage 1 is to develop Palmerston–Sheffield and Sheffield–Heybridge–Burnie 220 kV transmission corridors. The original scope for this stage was (along with Palmerston–Sheffield) to develop the Sheffield–Staverton–Hampshire Hills–Burnie–Heybridge 220 kV transmission corridor.

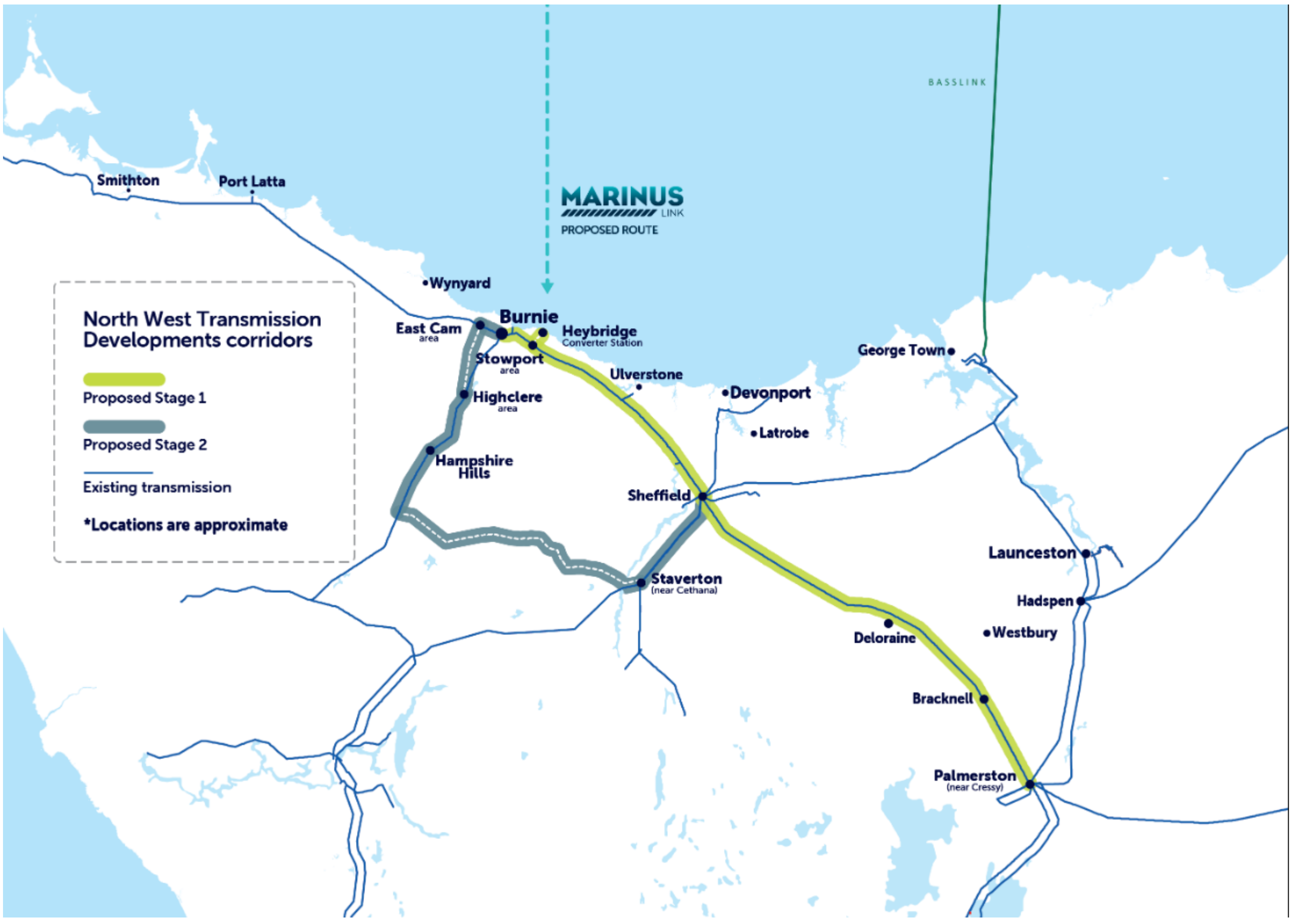

Figure 9-1 North West Transmission Developments revised scope

[21] https://www.marinuslink.com.au/2023/09/marinus-link-advances-under-new-deal/

[22] Delivering a Tasmanian electricity network ready to support Marinus Link and a clean energy future, 6 November 2023, https://talkwith.tasnetworks.com.au/north-west-transmission-developments-2

Though the North West Transmission Developments are to facilitate Marinus Link, it will also serve to support new generation and load in the North West Tasmania Renewable Energy Zone (**REZ**). Under the original scope, a number of new large-scale wind farms in the North West Tasmania REZ (specifically in the vicinity of Hampshire and far north-west Tasmania) and industrial load proposed to connect to a new 220 kV node at Hampshire Hills (also in the vicinity of Hampshire township but separate to the existing Hampshire Substation). In the revised scope, this new 220 kV network through Hampshire Hills does not exist and the existing transmission network in the area has very limited capacity to connect new generation and load. Therefore, this contingent project is needed to support the proposed new generation and load prior to the second stage of Marinus Link and North West Transmission Developments coming online.

9.1 North West Tasmania existing network

The transmission network in north-west Tasmania emanates from Sheffield Substation. The network mainly supports electricity supply to local communities, and connects the Bluff Point and Studland Bay wind farms. The existing network is not adequate to support large-scale developments such as interconnection, further wind farms, or major industrial loads. The existing transmission network in north-west Tasmania is presented in Figure 9-2.

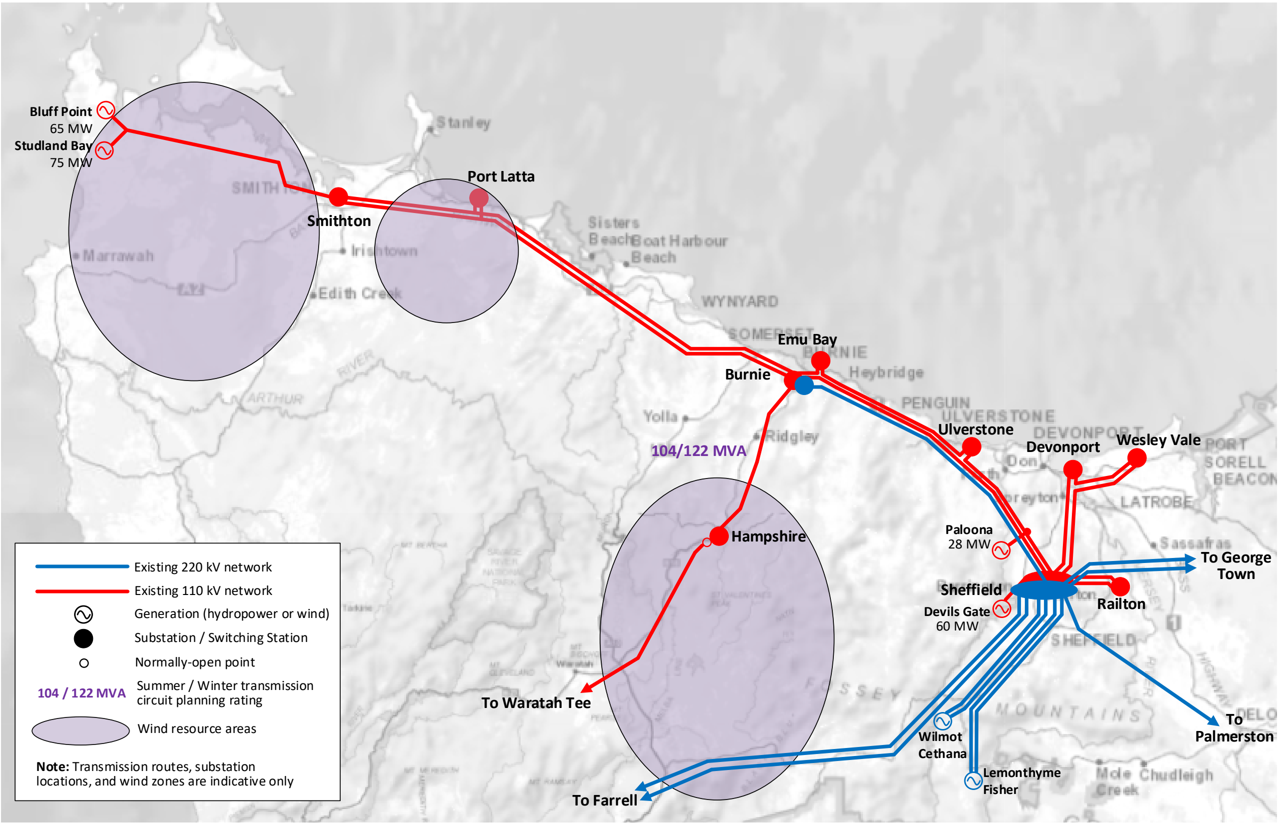

Figure 9-2 North-west Tasmania existing network

North West Tasmania is identified as one of Tasmania's three onshore renewable energy zones. The North West Tasmania REZ has excellent wind resources. With the Tasmanian Central Highlands REZ, it is amongst the top REZs across the National Electricity Market.[23] Resource locations for new large-scale wind generation is expected around the Hampshire area and far north west of Tasmania, as presented in Figure 9-2.

Hampshire is also a candidate site for new industrial load development. A number of new load proponents have proposed to establish at Hampshire in recent years.

The publicly-announced large-scale new wind farm and industrial load proposals in north-west Tasmania propose to connect at Hampshire. The existing network in this area is not adequate to support the expected level of development.

9.2 Existing network capability

The existing network in the vicinity of Hampshire consists solely of the Burnie–Hampshire 110 kV transmission line. This is a single-circuit transmission line with a summer/winter transmission planning rating of 104/122 MVA. This circuit exists to supply a small load at the existing Hampshire Substation and provide a backup supply path to West Coast Tasmania through the Waratah Tee.

Though TasNetworks generally applies dynamic ratings (utilising real-time temperature and wind speed data) to transmission lines, single-circuit radial lines are not normally operated in this manner due to the lack of redundant pathways. Therefore, the Burnie–Hampshire 110 kV transmission line is considered to have a thermal rating of 104 MVA to accommodate new generation or load.

In any case, the amount of generation or load that can be accommodated on a single-circuit in Tasmania is 144 MW. This is to comply with the Frequency Operating Standards for Tasmania, which sets the largest single generation, load, or network event at 144 MW in Tasmania to ensure adequate frequency reserves should a continency event occur.

9.3 Identification of trigger

The primary trigger to upgrade the North West Tasmania REZ network is the amount of new wind generation or load that can be accommodated into the existing network at Hampshire until the transmission line capability is reached.

The thermal capability of the Burnie–Hampshire 110 kV transmission line is 104 MVA, constrained by the summer rating of the line. There is a small existing load only at Hampshire Substation, meaning the entirety of transmission line capacity is available to new connecting party. This is permissible on the assumption that other power system parameters are met (either by the network or connecting party).

On this basis, the identified technical trigger for either new generation or load is 100 MW. At this point, the existing transmission network capacity is exhausted and this North West Network Upgrade project is required.

[23] 2023 IASR Assumptions Workbook (Capacity Factors tab) AEMO, published 28 July 2023 https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

9.4 Probability to occur in the regulatory control period

This section demonstrates the probability of new generation and load in north-west Tasmania, sufficient to meet the proposed trigger. There are three levels of justification that provide—while not certain—it is probable that more than 100 MW of new generation or load will become committed to connect to Hampshire in north-west Tasmania in the 2024–29 regulatory control period.

9.4.1 Publicly-announced new generation proposals

There are currently four large-scale publicly-announced wind farm proposals in the North West Tasmania REZ proposing to connect to Hampshire, with capacity totalling more than 1,600 MW. These proposals are presented in Table 9-1.[24]

Table 9-1 North West Tasmania REZ publicly-announced generation proposals

Wind farm	Capacity (MW)
Guildford	525
Hellyer	155
Robbins Island (including Jims Plain)	929
Total	**1,609**

The Jims Plain and Robbins Island renewable energy parks[25] (predominantly wind energy, with some solar energy and battery storage) are two separate projects, but are often referenced simply by the larger Robbins Island Wind Farm. The projects are closely located in far north-west Tasmania, are proposed to connect via a common transmission line, and are being developed by the one proponent. The projects will also be staged, with the first stage potentially proceeding without Marinus Link, and future stage(s) with Marinus Link. The project proponent states the potential of the projects as Jims Plain up to 200 MW of wind energy and 40 MW of solar energy, and Robbins Island up to 340 MW in stage 1 and up to 900 MW in total.

All projects are within the Hampshire area or far north-west Tasmania, and propose to connect to the transmission network at Hampshire. All proposals have lodged connection enquiry with TasNetworks under the NER, and are at varying stages of the project approval process.

It is probable that at least 100 MW of the 1,609 MW publicly-announced new wind generation projects in the North West Tasmania REZ (proposed to connect to Hampshire) will be become committed (or connect) in the 2024–29 regulatory control period.

9.4.2 Tasmanian Renewable Energy Target

As presented in Section 8.4.2, the Tasmanian Renewable Energy Target will require 1,500 MW of new wind generation by 2030 in Tasmania to meet the interim target. Given this substantial amount, new wind generation will be required across Tasmania's three onshore REZs to achieve this target.

It is probable that at least 100 MW of the 1,500 MW target will become committed (or connect) in the 2024–29 regulatory control period to connect to Hampshire in north-west Tasmania, due to the strong wind resource.

[24] NEM Generation Information October 2023 https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
[25] https://robbinsislandwind.com.au/

9.4.3 Publicly-announced new load proposals

There is currently one large industrial load proposed in north-west Tasmania in the vicinity of Hampshire.[26] This is an efuels production facility by HIF Tasmania. This proposal is presented in Table 9-2.

Table 9-2 North West Tasmania REZ publicly-announced load proposals

Load	Capacity (MW)
HIF Tasmania	250

The HIF Tasmania efuels facility proposes to connect to the transmission network at Hampshire, has lodged a connection enquiry with TasNetworks under the NER, and is somewhat advanced through its project approval process. It expects to commence operations mid-2026.

As the majority of the proposed demand is electrolysis, it is possible that the project may become staged with lesser electrolyser capacity (and hence demand) in the first instance.

It is probable that at least 100 MW of proposed HIF Tasmania efuels facility will be become committed (or connect) in the 2024–29 regulatory control period.

9.5 Project triggers

The proposed triggers for the North West Network Upgrade project are as set out below. Trigger 1 is the technical trigger identifying the existing network limitation, while triggers 2 & 3 are standard triggers consistent with our other proposed contingent projects.

1. commitment of at least 100 MW of new generation or load to connect at Hampshire;
2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates upgrading the network in North West Tasmania 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.

9.6 Indicative solution and cost

The indicative solution and cost for the North West Network Upgrade is a new double-circuit Burnie–Hampshire Hills 220 kV transmission line, with a new 220 kV switching station at Hampshire Hills. This will provide a network connection point of sufficient capacity to facilitate the proposed new wind generation and industrial load in north-west Tasmania. The project is estimated to cost $174 million.

10 Summary

To avoid non-compliance with the ESI regulations, an additional 210 MW load will require:

- construction of a new 220 kV double circuit transmission line between Sheffield and Palmerston;
- rearrangement of the existing George Town Substation and the construction of a new substation; and
- installation of additional reactive support in George Town.

[26] https://www.hiftasmania.com.au/

In our Original Proposal, these three augmentations were classified as three separate contingent projects. Following further analysis, TasNetworks had determined that all three projects are needed to address the same non-compliance following new load at George Town.

A double circuit failure of Sheffield–George Town or Hadspen–George Town 220 kV lines can cause a system black event with additional load of 210 MW in George Town area. This can occur when the system is unstable after a double circuit failure. The identified solution to address this limitation is to bring forward the Palmerston–Sheffield augmentation proposed under Marinus in 2029. The Palmerston to Sheffield Network Upgrade remains as a separate project in our Revised Proposal given it could also be delivered through Project Marinus. TasNetworks considers proposing this augmentation as a separate contingent project provides transparency for customers.

The George Town Substation reaches a non-compliance limit with ESI regulations on system black with additional load of 210 MW. This is a very high risk condition with the current arrangement of the substation (i.e., limited physical distances between equipment and inability to re-arrange facilities in an emergency). Furthermore, at similar load levels, it is economical to consider a new substation rather than connecting to the existing substation.

Despite the Palmerston to Sheffield Network Upgrade, system instability can still occur following a double circuit failure supplying George Town. Dynamic reactive support is required following the connection of 210 MW of new load at George Town. As the trigger level and need for the substation and reactive support augmentations are same, TasNetworks has combined these projects into a single contingent project called the George Town Network Upgrade. Economic analysis shows that the incremental benefits of dynamic reactive support by avoiding instability limits are sufficient to offset the cost even under the existing load at George Town Substation.

Despite the above investments, the reactive power requirement will continue to grow as new load connects at George Town. We consider a further 140 MW of new load (350 MW increase from current load) is sufficient to introduce stability constraints and trigger the requirement for the George Town Reactive Support project.

As significant load increase is expected in George Town, the technical analysis was extended to understand the instability limits due to a double circuit failure. Market simulation and economic analysis was conducted to understand the economic trigger to implement the Sheffield to George Town Network Upgrade against constraining the network. The analysis shows that the economic trigger for this project is 712 MW of new load.

New generation in the Central Highlands REZ will introduce a constraint in the Waddamana–Palmerston transmission corridor. Constraints will occur with 660 MW of new wind generation in the REZ. It is probable that this amount of new generation will become committed (or connect) within the 2024–29 regulatory control period, with existing publicly-announced proposals, to assist in meeting the TRET interim target by 2030, and as forecast in the ISP.

Lastly, a new contingent project is identified for this Revised Proposal. Following changes to the proposed North West Transmission Developments to support Marinus Link, proposed new wind generation and/or industrial load to connect to Hampshire will become constrained given the weak existing network. Constraints will occur with 100 MW of new wind generation or load connecting to Hampshire. It is probable that this will occur with the expected amount of new generation and load to become committed (or connect) within the 2024–29 regulatory control period. The identified contingent project is a new Burnie–Hampshire Hills 220 kV transmission line and Hampshire Hills Switching Station.

11 Appendix A: Revised triggers for 2024-29 Contingent Projects

Project	Amended Triggers
Palmerston to Sheffield Network Upgrade	1. Commitment of at least 210 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T 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.
George Town Network Upgrade	1. Commitment of at least 210 MW of additional load to connect to the transmission network at George Town substation 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates a network investment 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.
George Town Reactive Support	1. Commitment of at least 350 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates a network investment 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.
Sheffield to George Town Network Upgrade	1. Commitment of at least 712 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates that 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.
Waddamana to Palmerston transfer capability upgrade	1. Commitment of at least 660 MW of new generation in the Central Highlands REZ 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates upgrading the transfer capability of the Waddamana–Palmerston transmission corridor 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.
North West Network Upgrade	1. Commitment of at least 100 MW of new generation or load to connect at Hampshire 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates upgrading the network in North West Tasmania is the preferred option that provides net market benefits and / or addresses a reliability corrective action

Project	Amended Triggers
	3. TasNetworks' Board commitment to proceed with the project subject, to the AER amending the revenue determination pursuant to the NER.