Addressing reliability requirements in the Cape River network area

Notice of no non-network options

Publication Date: 13th December 2019

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1. Description of the identified need

Cape River 66/11kV Substation (CARI) is an integral node in the North Queensland mid-west 66kV sub transmission network which supplies 4,102 customers (directly and indirectly).and two major renewable generation projects in the Hughenden area.

CARI was built in the mid-1960s and a significant portion of the primary plant is now at or approaching the assessed end of life based on age and condition. CARI consists of four 66kV feeder bays, a 66kV voltage regulator, a 66/11kV 1MVA power transformer and two outdoor 11kV feeder bays.

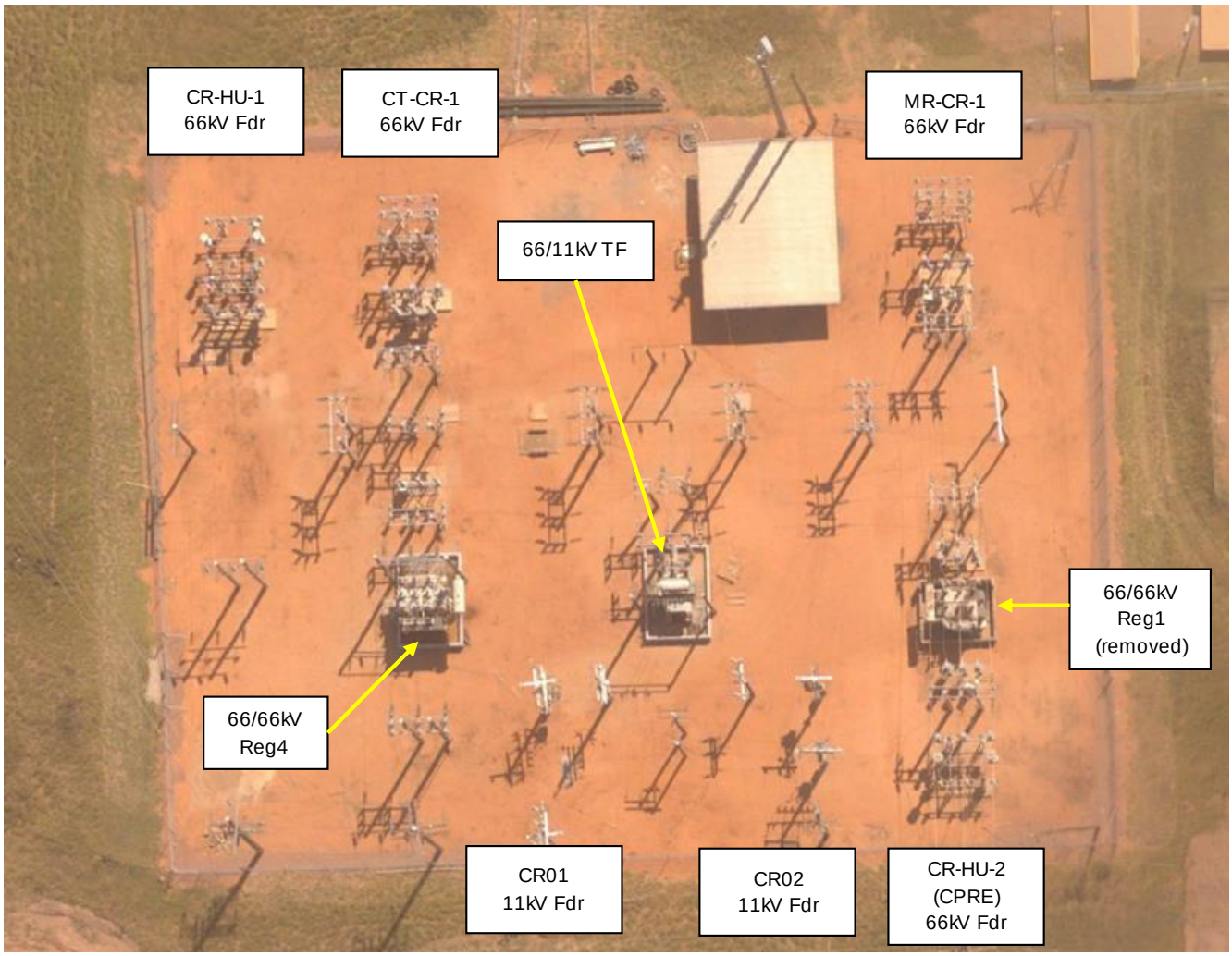


Figure 1 Aerial image of Cape River Substation

Based on a Condition Based Risk Management (CBRM) analysis of the effect of current condition and ageing on the expected life of the asset, the following have been deemed to reach retirement age:

- The 66/11 kV 1MVA transformer (YOM 1954) is 65 years old and is poor condition.
- The C152 (CT-CR-1 Fdr) and D152 (CR-HU-1 Fdr) 66 kV circuit breakers are of ABB HLC type. These are part of a REPEX replacement program due to a known potentially explosive failure mode. The roller contacts on ABB HLC circuit breakers of the same make and model at other sites in the network have failed. The hazard exists if there is

insufficient contact pressure between the moving contact and the roller contact frame if one or more of the roller contacts is / are missing with the circuit breaker in the closed position. This may lead to arcing across this point resulting in generation of gas bubbles and an increase in internal pressure within the circuit breaker with the pressure causing eventual failure of the circuit breaker.

- There are approximately ten 66kV timber pole isolator structures and a number of other timber pole support structures for the 66kV overhead bus. The condition of the poles is not known, however site photos shows that a number of the timber poles at this site are supported by pole nails.

- Additionally, asbestos has been identified in the internal walls, ceiling, soffit and external walls of the control building at CARI. Ergon Energy has a strategy to remove all asbestos containing materials from our assets, to minimise staff and contractor exposure to respirable asbestos fibres.

The deteriorated condition of the assets at Cape River Substation poses significant safety risks to staff working in proximity to these assets and reliability of supply risks to customers supplied from Cape River Substation.

Ergon Energy Corporation Limited (Ergon Energy) is responsible under its Distribution Authority D01/99 for electricity supply to the Townsville area in North Queensland. A fundamental requirement of Ergon Energy's Distribution Authority is to comply with the Minimum Service Standards and Safety Net Targets that seek to effectively mitigate the risk of low probability – high consequence network outages to avoid unexpected customer hardship and / or significant community or economic disruption. Details on Ergon Energy's Minimum Service Standards and Safety Net Targets are included in Appendix B.

A condition of Ergon Energy's Distribution Authority is to comply with all applicable legislation. Accordingly, clause 42 of the *Queensland Electricity Act 1994* requires the entity to operate, maintain (including repair and replace as necessary) and protect its supply network to ensure the adequate, economic, reliable and safe connection and supply of electricity to its customers.

The identified need for investment is to remediate the safety and reliability risks currently associated with the aged assets at Cape River Substation in order to maintain a safe, reliable supply of electricity to customers in the Cape River region. Ergon Energy's proposed preferred network option to address the identified need is to replace the aged assets at Cape River Substation in a safe, cost-effective manner that minimises disruptions to customers.

Changes to the National Electricity Rules (NER) in July 2017[1] have meant that replacement plans for network assets are now subject to RIT-D. Accordingly, Ergon Energy has initiated a RIT-D to address the identified need associated with the aged assets at Cape River Substation.

This notice has been prepared under cl. 5.17.4(d) of the NER and summarises Ergon Energy's determination that no non-network option is, or forms a significant part of, any potential credible option for this RIT-D. In particular, it sets out the reason for Ergon Energy's determination, including the methodologies and assumptions used.

[1] https://www.aemc.gov.au/rule-changes/replacement-expenditure-planning-arrangements

1.1. Assumptions underpinning the identified need

The need to undertake action is predicated on the deteriorated condition of the assets at Cape River Substation which pose significant safety risks to staff working in proximity to these assets and reliability of supply risks to customers supplied from Cape River Substation.

The consequence of not addressing the condition based risks at Cape River Substation is that the assets will continue to deteriorate and ultimately fail presenting safety and reliability risks.

This section summarises the key assumptions underpinning the identified need for this RIT-D. It is recognised that the assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

1.1.1. Forecast Load Growth and Daily Load Profiles

Section 3 of this notice shows that there is minimal forecast load growth at Cape River Substation and the other mid-west substations supplied via Cape River substation including Hughenden, Richmond, Julia Creek, Stamford, Glenelg and Winton.

Although there is minimal load growth it is important to note that there are currently two renewable energy projects under development in the mid-west area which will substantially increase the loading on the sub transmission network between Charters Towers and Hughenden.

The average daily profile for the CARI 11kV load shown in section 3 of this notice is not expected to change significantly over the coming years. However the load profile could potentially be influenced by changes to customer generation or usage patterns and the uptake of electric vehicles and battery storage in the area.

The average daily load profile for the CARI 66kV feeders shown in section 3 of this notice will change after the new generators in the mid-west area are fully operational.

1.1.2. Increased risk of involuntary load shedding going forward

Failure of the single 66/11kV transformer at CARI would result in an outage to approximately 295 customers.

A sustained 66kV bus fault at CARI would result in loss of supply to at least 4,102 customers and two major generators. This includes loss of supply to entire rural towns such as Hughenden, Richmond, Julia Creek and Winton.

In the event of a 66/11kV transformer failure or 66kV bus fault at CARI Ergon Energy will use 'best endeavours' to restore supply deploying generation for the case of a transformer fault or isolation/repair of the faulted bus section for the case of a 66kV bus fault.

Although CARI is in a remote location, it has been assumed that generation can be deployed to restore supply to the Cape River 11kV network within 13 hours and for a majority of bus faults supply can typically be fully restored within 8 hours. The restoration times would generally be dependent on a number of factors including location of staff, time of fault, severity of the fault, asset accessibility, availability of suitable spares, weather conditions and would vary under extenuating circumstances such as a natural disaster scenario.

Figure 2 Photo showing pole nails on the 66 kV supporting structures at CARI

Based on the existing peak load profiles at CARI the load at risk over a 24 hour period would be in the order of 190MWh for a 66kV outage and 10.4MWh for a 11kV outage. Based on the assumed restoration times and generation deployment these figures would reduce to around 63.2MWh and 5.6MWh.

Based on Condition Based Risk Management (CBRM) analysis the probability of failure of 66kV primary plant (i.e. HLC circuit breaker) that would lead to a 66kV bus outage could occur as infrequently as once in 4.5 years. The average annual probability of failure (PoF) is therefore 0.22 and the estimated unserved energy in the next 10 years is estimated at 140MWh.

Based on Condition Based Risk Management (CBRM) analysis the probability of a 66/11kV transformer failure that would lead to an outage to the local 11kV distribution network could occur as infrequently as once in 20 years. The average annual probability of failure (PoF) is therefore 0.05 and the estimated unserved energy in the next 10 years is estimated at 2.8MWh.

2. Network characteristics

2.1. Geographic region

The geographic region covered by this RIT-D is Cape River Substation and the connected substations through its 66kV Network. Cape River Substation is located approximately 200km South-West of Townsville near the township of Pentland in the Mid-West area of the Northern Region of Ergon Energy's Network.

Figure 3 Mid-West 66kV sub transmission Network

2.2. Existing supply system

CARI is supplied via two 66kV feeders from Charters Towers (Charters Towers – Cape River and Millchester – Cape River feeders). The substation directly and indirectly supplies approximately 4,102 premises, 295 of these from the local 11kV distribution feeders and the remainder from the outgoing 66kV sub-transmission network which supplies Hughenden, Richmond, Julia Creek, Stamford, Glenelg and Winton substations.

The geographical location of the mid-west area substations and sub-transmission feeders are shown in the diagram below:

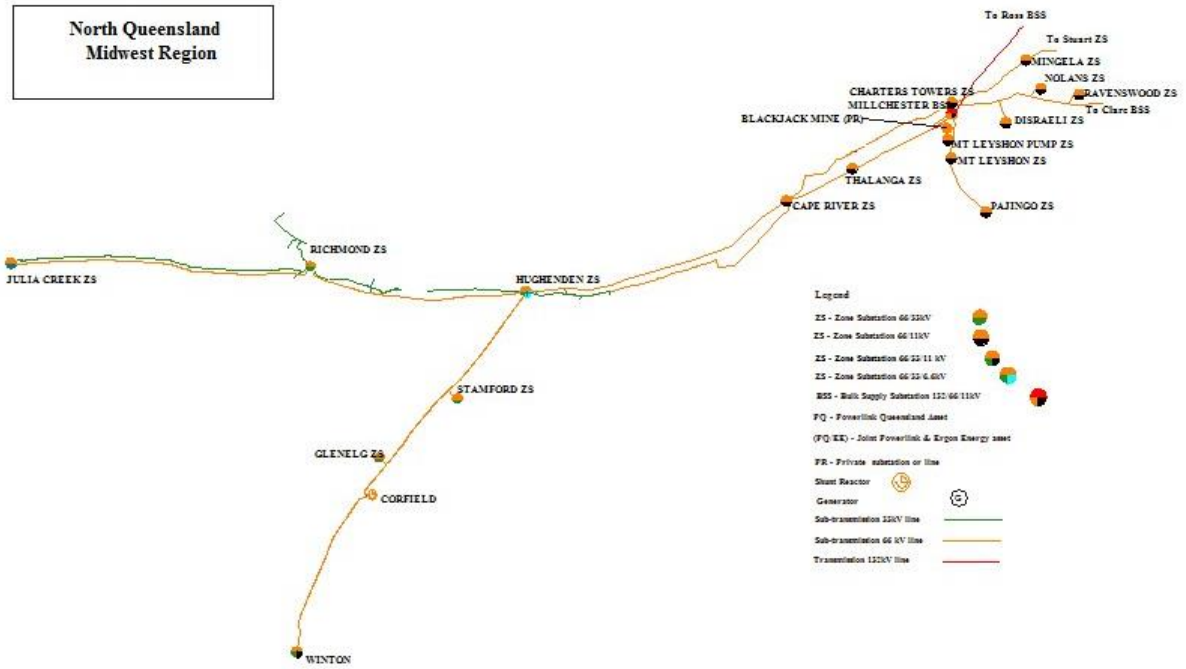


Figure 4 Geographical locations of Substations and Sub-Transmission Network in the NQ Mid-West Region

There are currently significant works under development on the Ergon network in this area as part of a generator connection project. These works include the establishment of two 132/66/33kV substations, Cape River East Substation (CPRE) which will be located adjacent to Cape River Substation and Jardine Creek Substation (JACR) which will be located approximately 20km east of Hughenden. A section of the Cape River – Hughenden 66kV feeder, which is predominantly a 132kV construction, will be energised at 132kV between CPRE and JACR substations.

The CPRE substation layout has been designed to cater for the future retirement of the CARI substation with an allowance for additional 66kV feeder bays and a spare 33kV indoor bay for the connection of a 33/11kV power transformer.

Figure 5 Aerial image showing the location of CPRE in relation to the existing CARI site

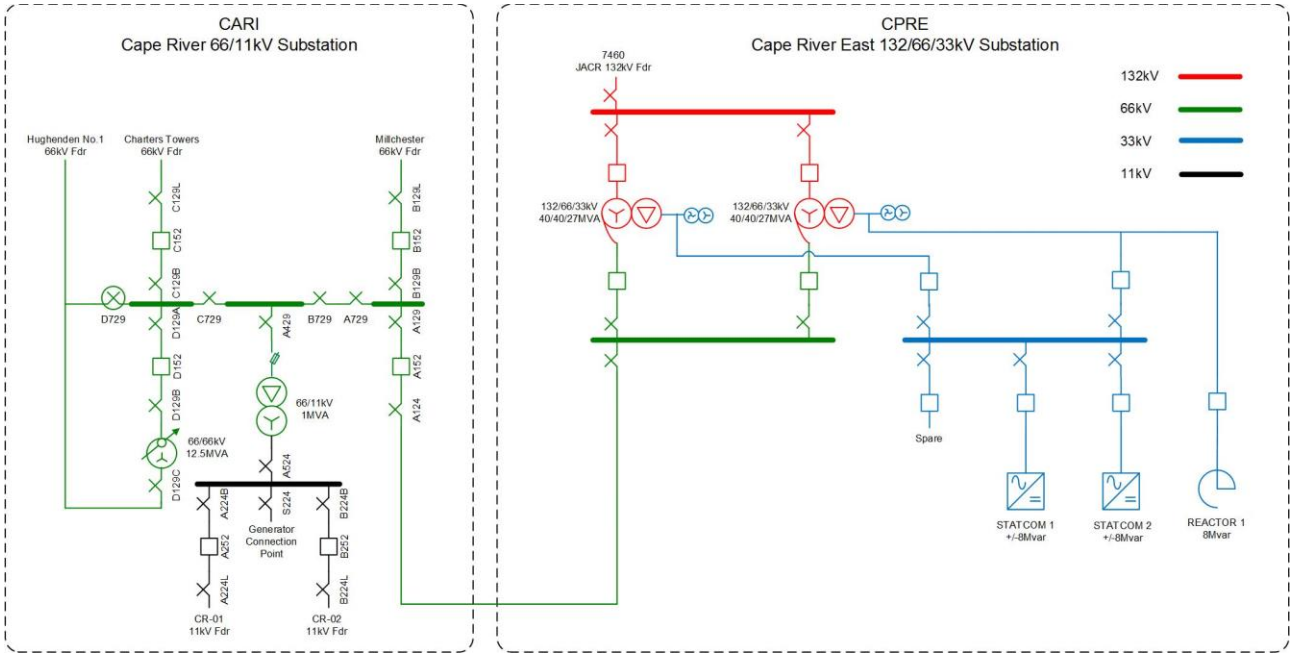


Figure 6 Single Line Diagram of CARI and CPRE substations

3. Forecast load and capacity

3.1. Load Forecast and Capacity

There is presently adequate capacity at Cape River Substation to service the forecast loads in compliance with the Safety Net Targets.

	Normal Summer Cyclic Capacity (NCC)	Emergency Summer Cyclic Capacity (ECC)
Cape River Substation 66/11kV TF1	1.05MVA	1.05MVA
Cape River Substation 66/66kV Reg4	12MVA	12MVA

Table 1 Cape River Substation Capacities

	Year	2019			2020			2021			2022			2023		
	Ratings Period	SD	SE	SNM	SD	SE	SNM	SD	SE	SNM	SD	SE	SNM	SD	SE	SNM
Feeder Name	Variable															
CR-HU-1	% of Rated A	26.4	43.8	34.5	24.9	42.6	33.6	25.0	42.7	33.7	26.0	43.0	34.3	26.4	43.4	34.6
	Loading (A)	31	70	54	29	68	52	29	68	53	30	69	54	31	69	54
	Power Factor	0.63	0.69	0.71	0.64	0.70	0.72	0.63	0.70	0.72	0.62	0.70	0.71	0.63	0.70	0.71
	Rating (A)	116	160	156	116	160	156	116	160	156	116	160	156	116	160	156
CR-HU-2	% of Rated A	16.6	34.8	29.7	15.7	33.8	28.9	15.8	33.9	29.0	16.3	34.2	29.5	16.7	34.5	29.8
	Loading (A)	31	71	55	30	69	53	30	70	54	31	70	55	31	71	55
	Power Factor	0.77	0.80	0.82	0.78	0.81	0.83	0.78	0.80	0.83	0.77	0.80	0.82	0.77	0.80	0.82
	Rating (A)	188	205	185	188	205	185	188	205	185	188	205	185	188	205	185
CT-CR-1	% of Rated A	26.0	39.6	36.5	25.3	38.7	35.8	25.3	38.8	35.9	25.8	39.0	36.4	26.1	39.3	36.6
	Loading (A)	48	79	66	46	77	64	47	78	65	47	78	66	48	79	66
	Power Factor	0.54	0.74	0.68	0.53	0.73	0.68	0.53	0.73	0.68	0.53	0.74	0.68	0.54	0.74	0.68
	Rating (A)	184	200	180	184	200	180	184	200	180	184	200	180	184	200	180
MR-CR-1	% of Rated A	43.9	49.6	41.4	42.5	48.4	40.5	42.6	48.6	40.6	43.5	49.0	41.3	44.0	49.3	41.5
	Loading (A)	68	114	94	66	111	92	66	111	92	67	112	93	68	113	94
	Power Factor	0.88	0.94	0.92	0.87	0.93	0.91	0.87	0.93	0.91	0.88	0.94	0.91	0.88	0.94	0.92
	Rating (A)	155	229	226	155	229	226	155	229	226	155	229	226	155	229	226

Table 2 Sub transmission Feeder Forecast and Ratings from 2018 DAPR[2]

The table above shows the system normal forecast loadings and ratings from the 2018 Distribution Annual Planning Report for the 66kV feeders that connect to Cape River substation. It is important to note that this forecast hasn't allowed for the additional loading expected from the new generation projects in the mid-west area.

The plots below show the historical maximum demands and the 50% Probability of Exceedance (50 PoE) forecast demands for the Cape River Substation 11kV load and the substations supplied from the Cape River 66kV feeders.

[2] https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report. Note that the ratings of the feeders presented in this table are currently being reviewed and therefore may not provide an accurate representation of the actual ratings.

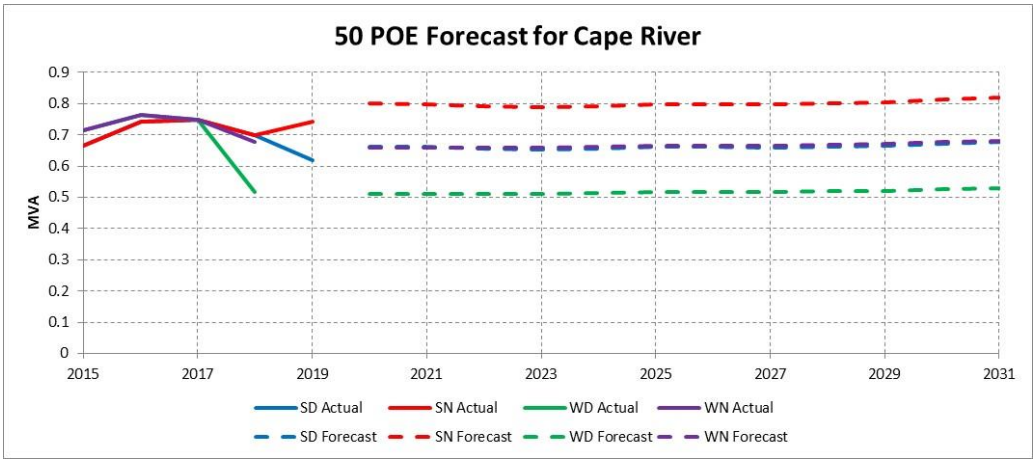


Figure 7 50 PoE Demand Forecast for the Cape River Substation 11kV load

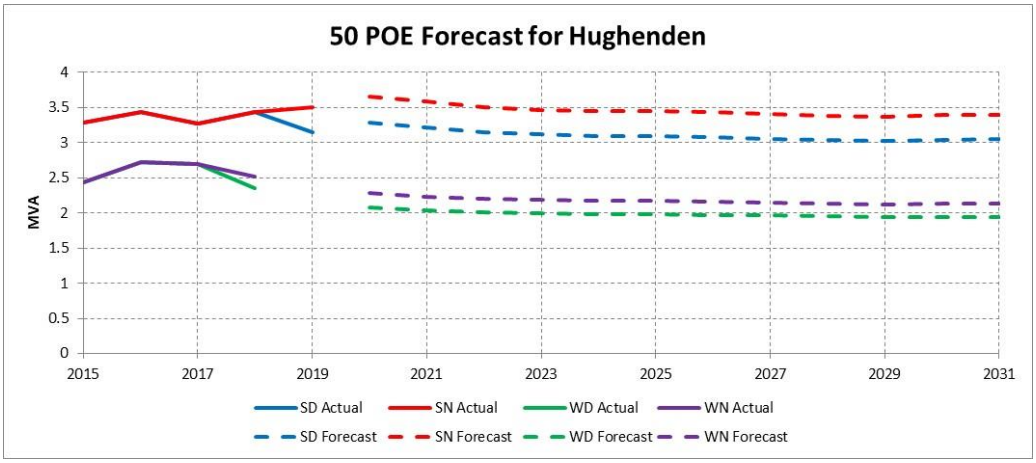


Figure 8 50 PoE Demand Forecast for the Hughenden Substation 33kV load

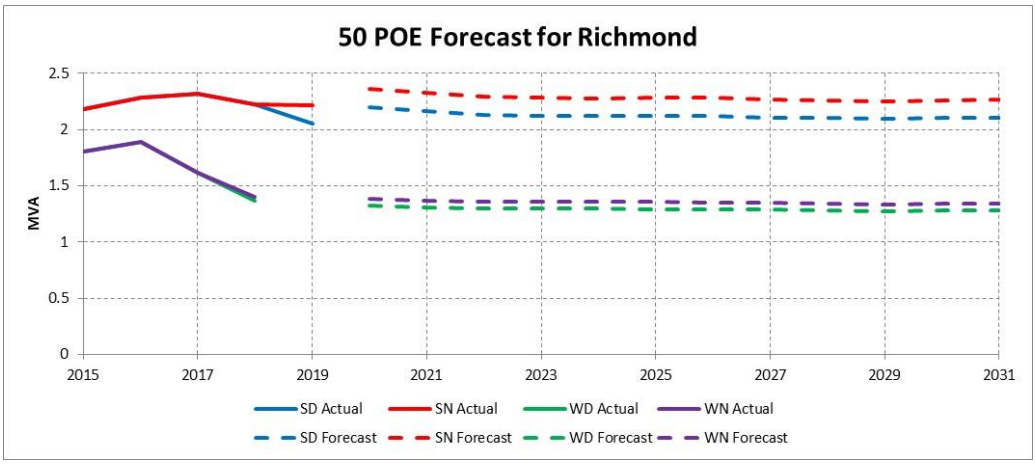


Figure 9 50 PoE Demand Forecast for the Richmond Substation 33kV load

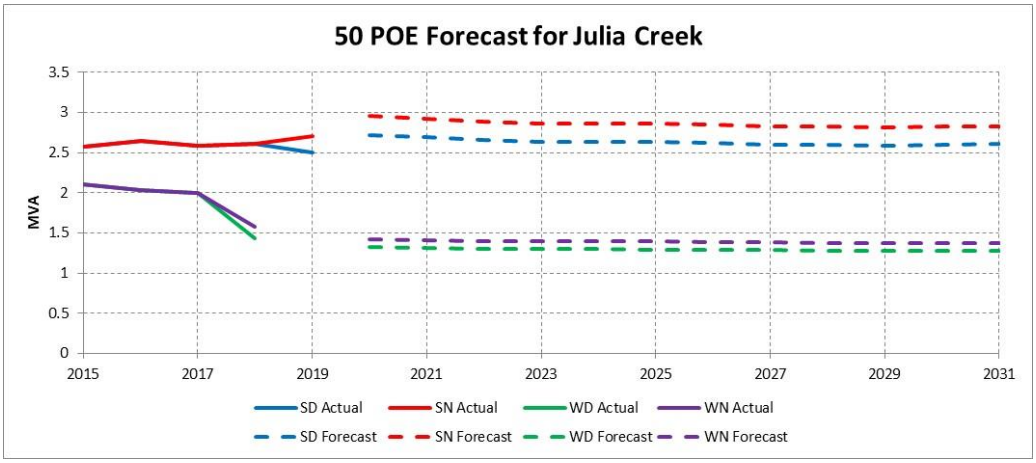


Figure 10 50 PoE Demand Forecast for the Julia Creek Substation 33kV load

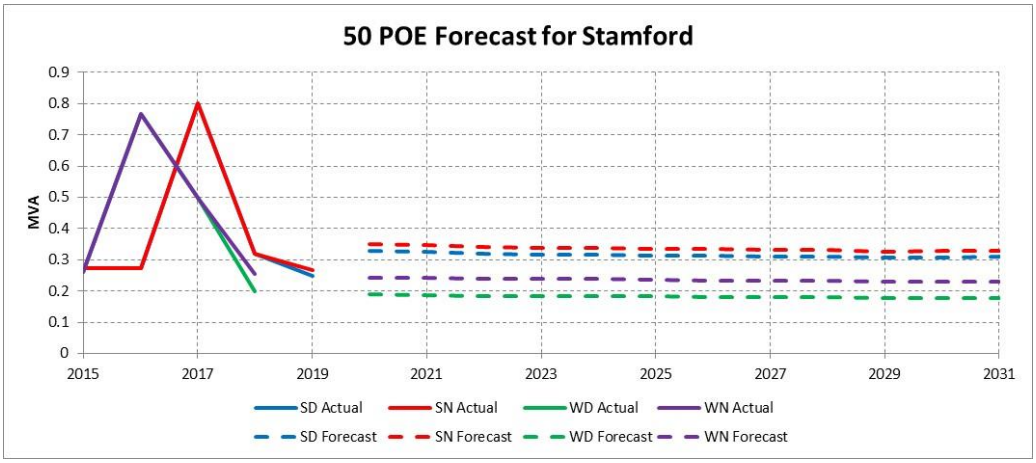


Figure 11 50 PoE Demand Forecast for the Stamford Substation 33kV load

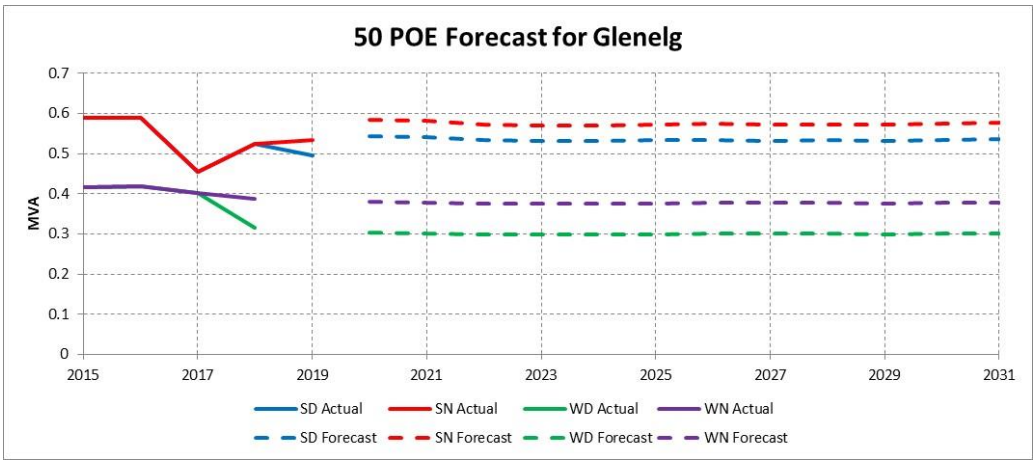


Figure 12 50 PoE Demand Forecast for the Glenelg Substation 33kV load

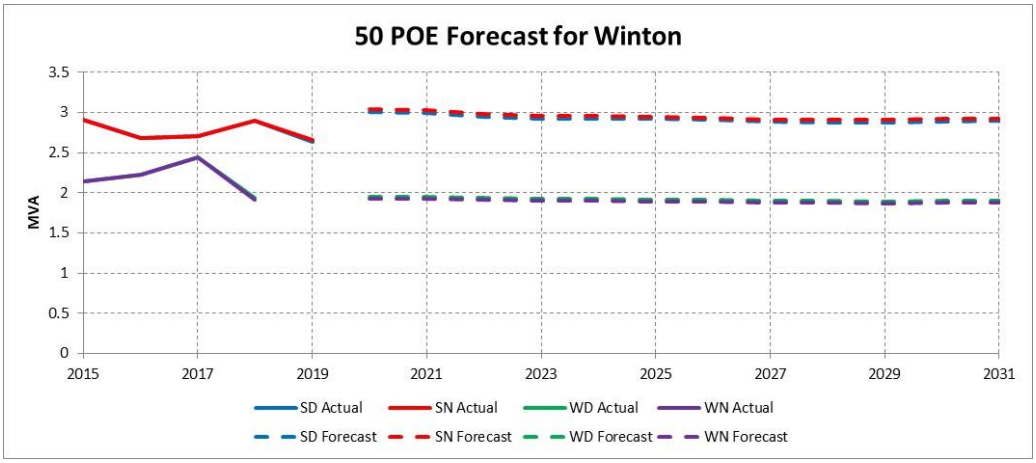


Figure 13 50 PoE Demand Forecast for the Winton Substation 11kV load

As shown in the plots above there is minimal forecast load growth at Cape River Substation and the other mid-west substations supplied via Cape River substation including Hughenden, Richmond, Julia Creek, Stamford, Glenelg and Winton.

Although there is minimal load growth it is important to note that there are currently two renewable energy projects under development in the mid-west area which will substantially increase the loading on the sub transmission network between Charters Towers and Hughenden.

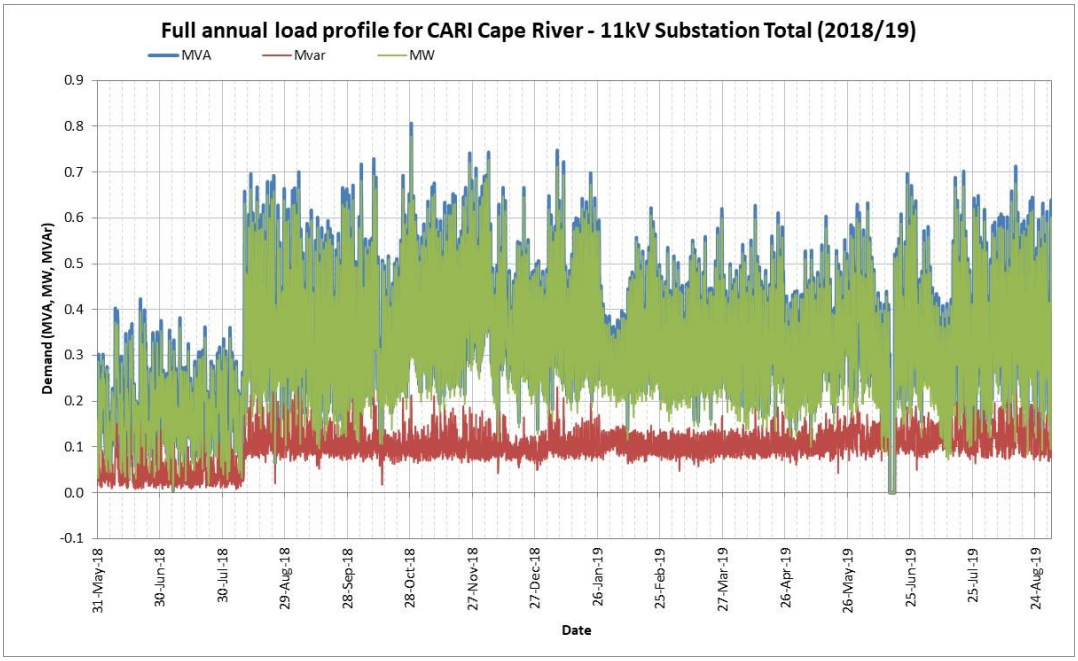


Figure 14 CARI 11kV load profile (2018/19)

The plot above shows the half hourly average daily load profile for Cape River Substation 11kV load for the 2018/19 period. Note that the data shown in the plot prior to July 2018 is incorrect due to a metering issue.

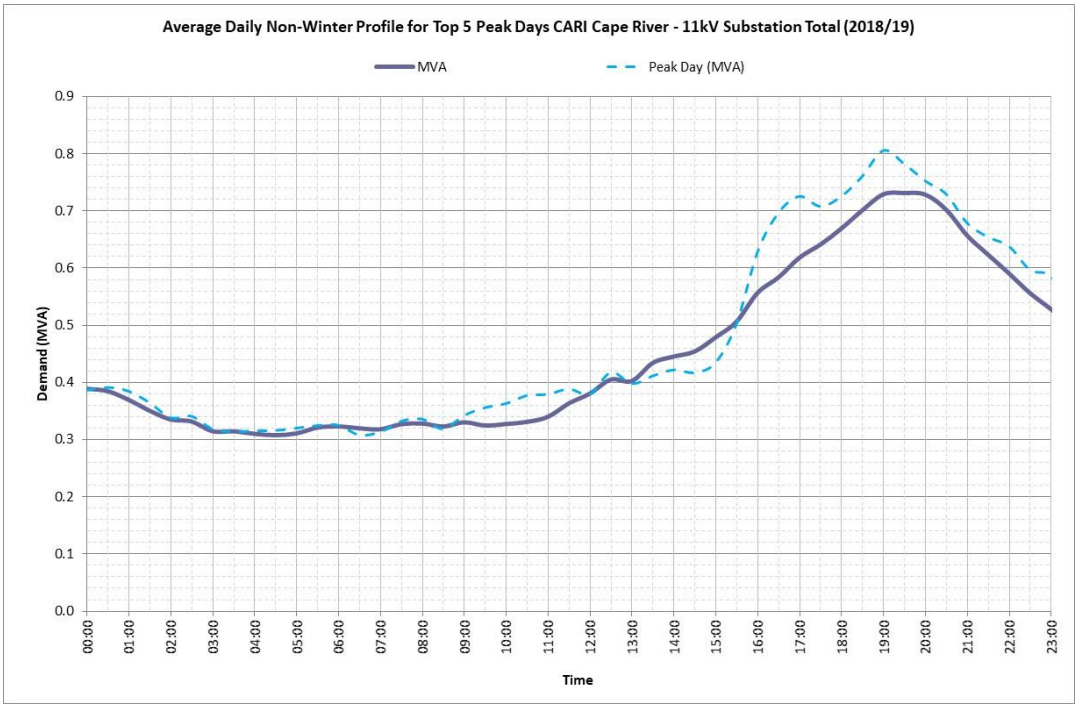


Figure 15 CARI 11kV load profile – Average of Top 5 Peak Days (2018/19)

The summer peak for the Cape River Substation 11kV load typically occurs in the early evening as shown in the plot above.

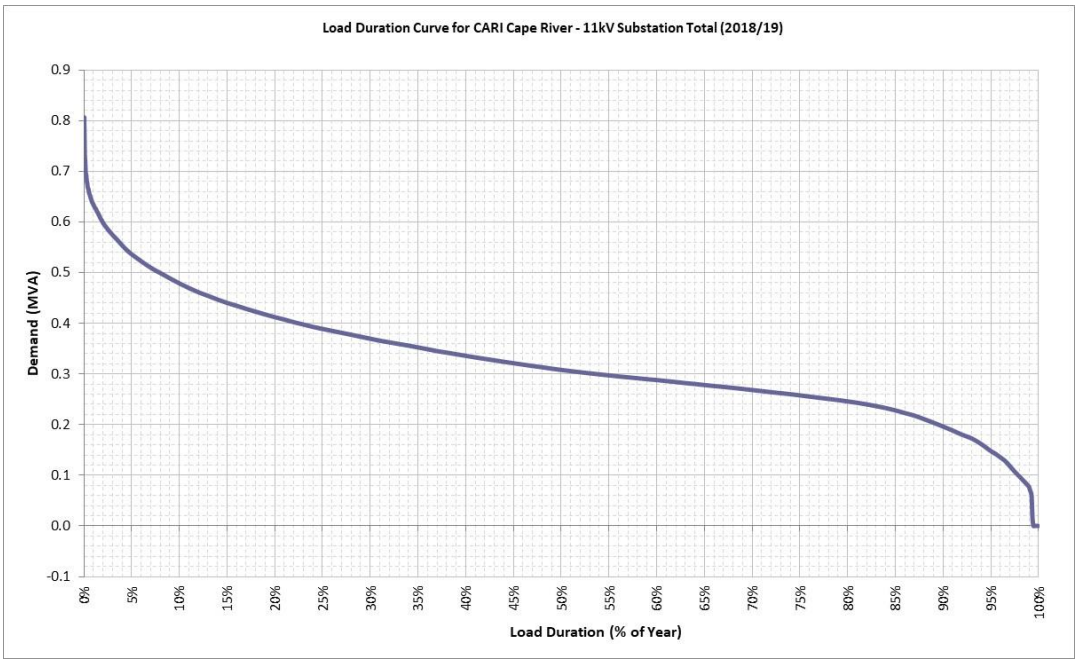


Figure 16 CARI 11kV Load Duration Curve (2018/19)

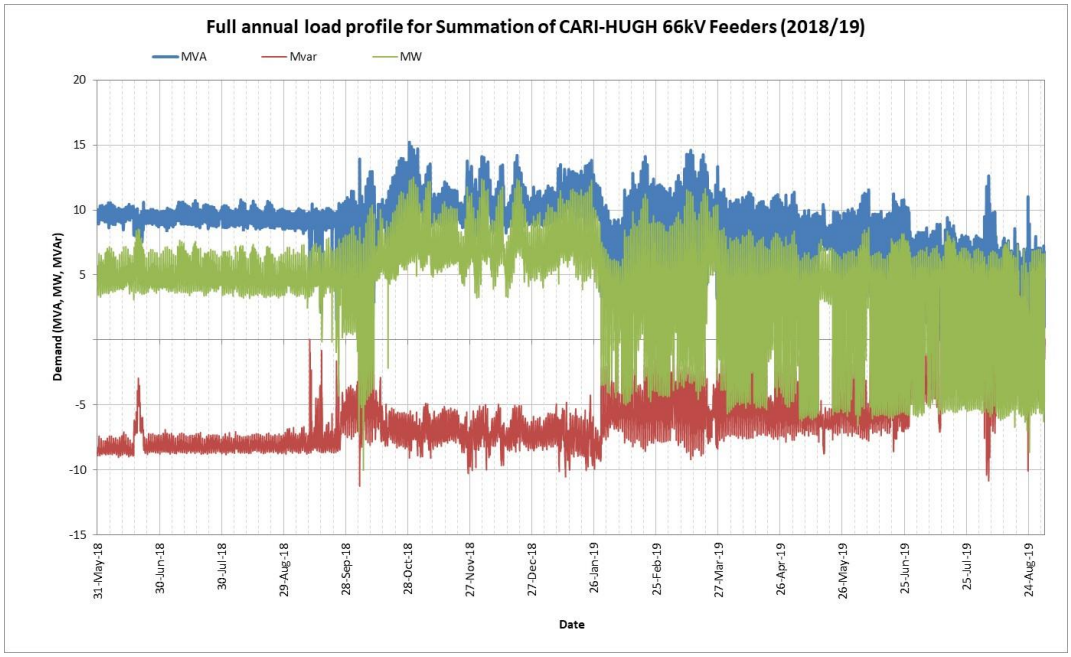


Figure 17 Summated CARI-HUGH 66kV feeders load profile (2018/19)

The plot above shows the half hourly average daily load profile for the summation of the CARI-HUGH 66kV feeders for the 2018/19 period. The change in power flows from positive to negative is due to export from one of the new generators in the mid-west area.

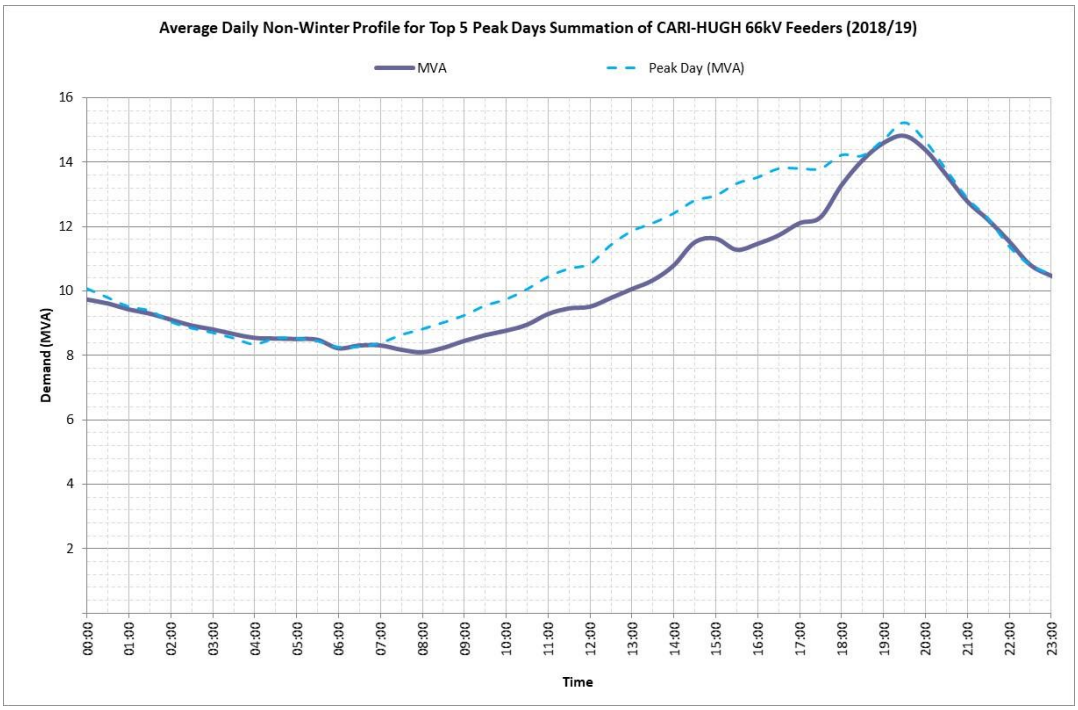


Figure 18 Summated CARI-HUGH 66kV feeders load profile – Average of Top 5 Peak Days (2018/19)

The summer peak for the summation of the CARI-HUGH 66kV feeders load typically occurs in the early evening as shown in the plot above. The average daily load profile for these feeders will change after the new generators in the mid-west area are fully operational.

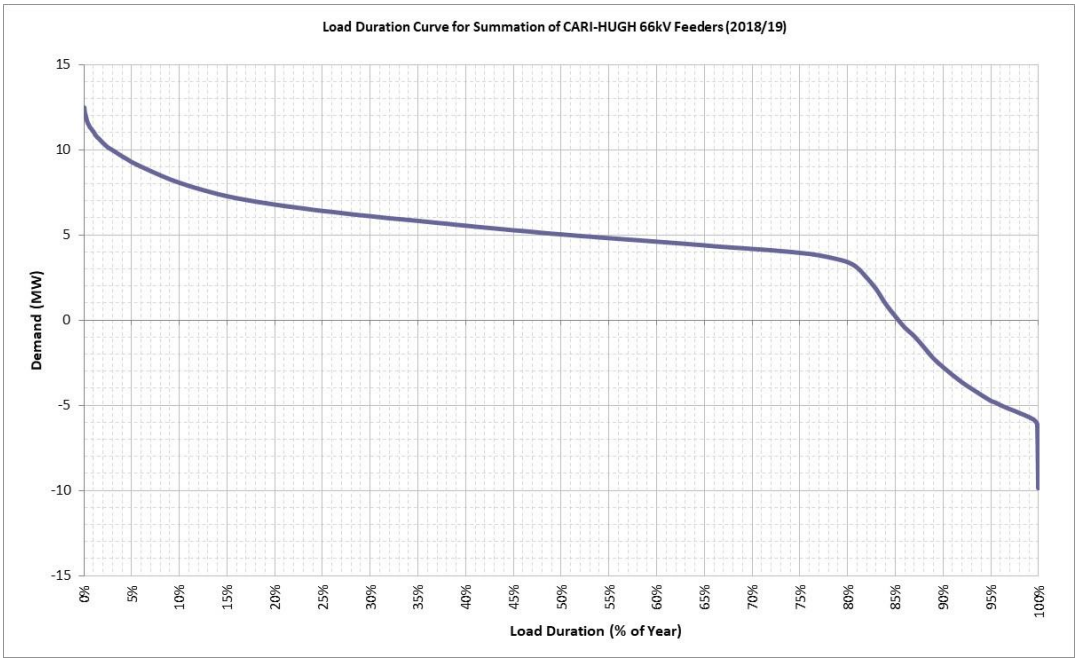


Figure 19 Summated CARI-HUGH 66kV feeders Load Duration Curve (2018/19)

3.2. Customer Statistics

Approximately 295 customers are directly supplied from Cape River Substation via the 11kV distribution network and approximately 4102 customers are supplied via the Cape River 66kV network. The Cape River 66kV network includes the Cape River 11kV network and all the zone substations supplied from the Cape River 66kV feeders.

	Cape River Substation 11kV network	Cape River Substation 66kV network
Total Customers	295	4102
Residential	204	2561
Non-Residential	91	1541
Annual Energy (kWh)	2,582,665	53,137,302
Energy Residential (kWh)	1,386,972	21,707,590
Energy Non-Residential (kWh)	1,195,693	31,429,712
Inverter Energy Systems		
IES Count Residential	49	439
IES Count Non-Residential	9	133
IES Capacity Residential	247kVA	2412kVA
IES Capacity Non-Residential	52kVA	1233kVA

Table 3 Customer Statistics for the 2018/19 period

4. Proposed preferred network option

Ergon Energy investigated a number of network options to address the identified need at Cape River Substation.

The proposed preferred network option is to install a 33/11kV transformer, 66kV feeder bays, 11kV feeder bays and associated protection and control equipment at the adjacent Cape River East Substation and decommission the existing Cape River Substation. The estimated capital cost of the preferred option is $6.35 million. Annual operating costs associated with this new capex are estimated to be around $31,750 per annum (assumed to be 0.5 per cent of the capital cost). The proposed project timeline has design commencing in 2020/2021 and construction completed by 2022/2023.

The project at a high level will include;

Works at CPRE Substation:

- 2 x new outdoor 66kV feeder bays.
- CBs, CTs, VTs and line isolator to be installed in existing outdoor 66kV feeder bay.
- Extend switchyard including earth grid to allow for the installation of the 33/11kV transformer and outdoor 11kV feeder bays.
- 1 x 33/11kV 3MVA Dyn1 transformer with OLTC.
- UG cable from transformer to 33kV switch board.
- Outdoor 11kV bus, 1 x outdoor 11kV transformer bay, 2 x 11kV outdoor feeder bays, 11kV feeder tie isolator and 1 x 11kV generation connection point.
- New separate control building containing:
  - 66kV and 11kV feeder panels;
  - Communications and control panels;
- Relocate / reroute communications equipment from CARI to CPRE.
  - Communications pole and associated antennas (Mt Misery link, P25 radio)
  - Ubinet infrastructure and panels

CARI Substation:

- Decommission substation and remove redundant 66/11kV transformer, regulator, switchgear, CTs, VTs, isolators, structures, control building, footings, fencing, etc

66kV and 11kV feeders:

- Reroute Millchester, Charters Towers and Hughenden No.1 66kV feeders across to new bays at CPRE;
- Reroute CR-01 and CR-02 11kV feeders across to new bays at CPRE;
- Recover redundant line assets as far as practical.

The Single Line Diagram of CPRE substation below in Figure 20 shows the proposed network option.

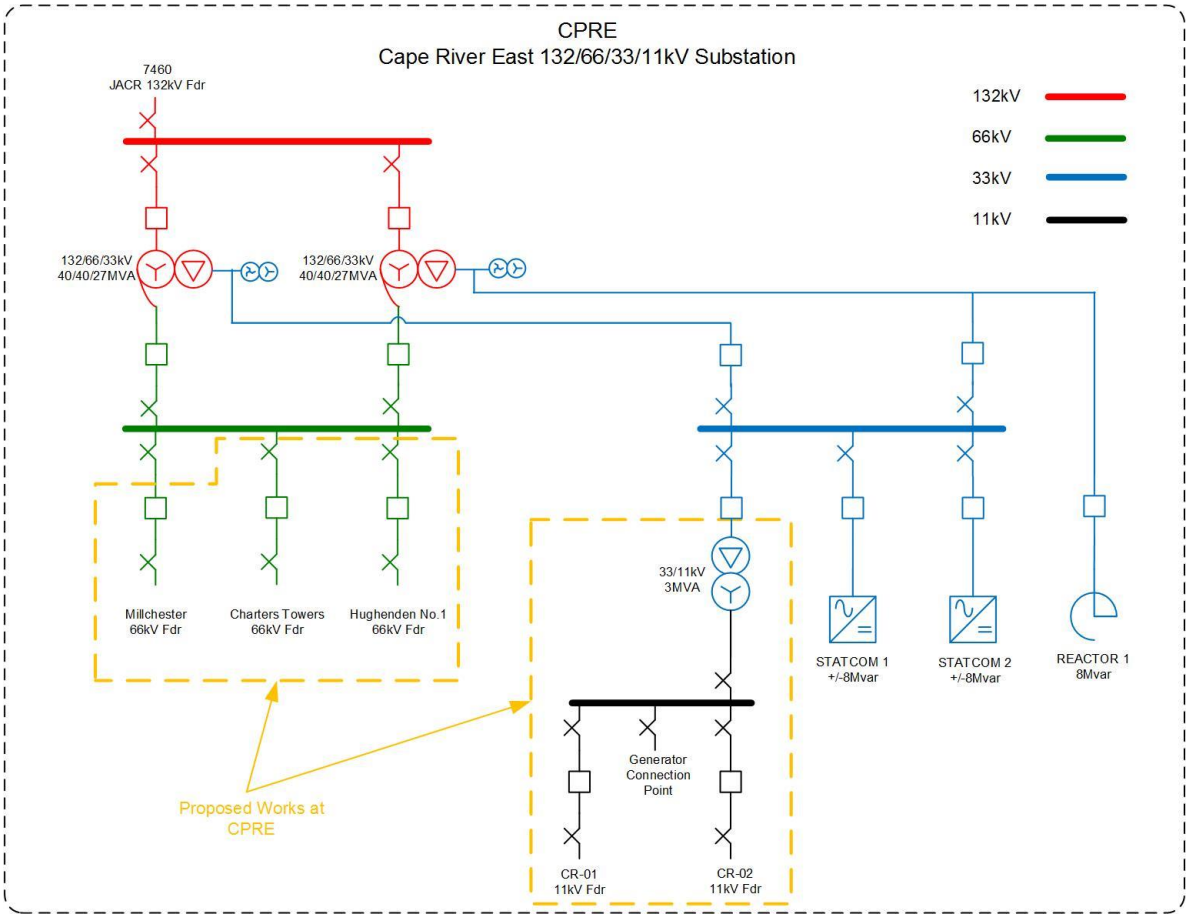


Figure 20 Single Line of CPRE showing proposed network option

5. Assessment of non-network solutions

A viable non-network solution to address the safety and reliability risks currently associated with the aged assets at Cape River Substation would need to replicate the capacity, reliability and functionality of the Cape River Substation on an enduring basis.

To be considered a feasible option, any non-network solution must be technically and commercially feasible and able to be implemented in sufficient time to satisfy the identified need in 2022 in order to avoid network investment.

5.1. Required demand management characteristics

A viable demand management solution that replaces the functionality of the Cape River Substation must be capable of supplying the mid-west 66kV load and 11kV load that is currently supplied from Cape River Substation. The demand management solution would also be required to meet the requirements of Ergon Energy's Minimum Service Standards and Safety Net Targets outlined in Appendix B.

The 66kV and 11kV load profiles for Cape River Substation from the 2018/19 period are shown in section 3.1. The demand management solution would be required to supply the forecast peak loading and the estimated annual energy at Cape River Substation as shown in Table 4 below:

Substation Load	Required Peak Load support MW[3]	Required Annual GWh	Days/Year
Cape River 11kV	0.8	2.58	365
Cape River 66kV	12.5	53.14	365

Table 4 Network support required for the CARI 66kV and 11kV load

5.2. Demand management options considered

Ergon Energy considered a number of demand management technologies to determine their commercial and technical feasibility to assist with the identified need in the Cape River network area.

5.2.1. Customer Energy efficiency and power factor correction

Energy efficiency and power factor correction while offering permanent reductions has been assessed as not technically viable as this would only contribute to a fraction of the support required for the Cape River Substation load.

5.2.2. Demand Response (curtailment of load)

Customer curtailment of load is an effective technique for network support where the need is for a short time period but is generally not viable for extended periods of time.

A small portion of the Cape River Substation residential load such as hot water systems, pool pumps and air conditioning is controllable load that can be switched off for short periods of time.

In the mid-west region large customer demand response is valued at $40-100 per kVA (excluding acquisition costs).

Targeted DM during the peak load periods on the Cape River 11kV network, if successful could reduce the size of the proposed 33/11kV transformer.

After the connection of the new generation projects to the mid-west sub-transmission network the Cape River 66kV feeders will reach their highest utilisation levels during the light load / peak generation scenarios. A reduction in demand would further increase these utilisation levels on the sub transmission network during peak generation scenarios.

These options have been assessed as technically not viable as they would not provide the identified demand reduction required at Cape River Substation and the load reduction would only be available for short periods of time.

5.2.3. Customer Solar Power / Energy Storage Systems

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS).

[3] Based on 50PoE Forecast Peak MW for the 2020-2031 period

There are currently around 572 customers connected to the mid-west network with inverter energy systems installed with a combined capacity of approximately 3645kVA.

At present, only a very small percentage of customer solar power systems are coupled with a BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when network support is required.

This option has been assessed as technically not viable as it would not provide the identified demand reduction required to support the Cape River Substation loads, would only provide support during daylight hours and the majority of these systems cease to operate during a network outage.

5.2.4. Large Scale Customer Generation / Energy Storage

Large scale customer generation or energy storage is an effective technique for network support where the need is for a short time period but is generally not viable for extended periods of time.

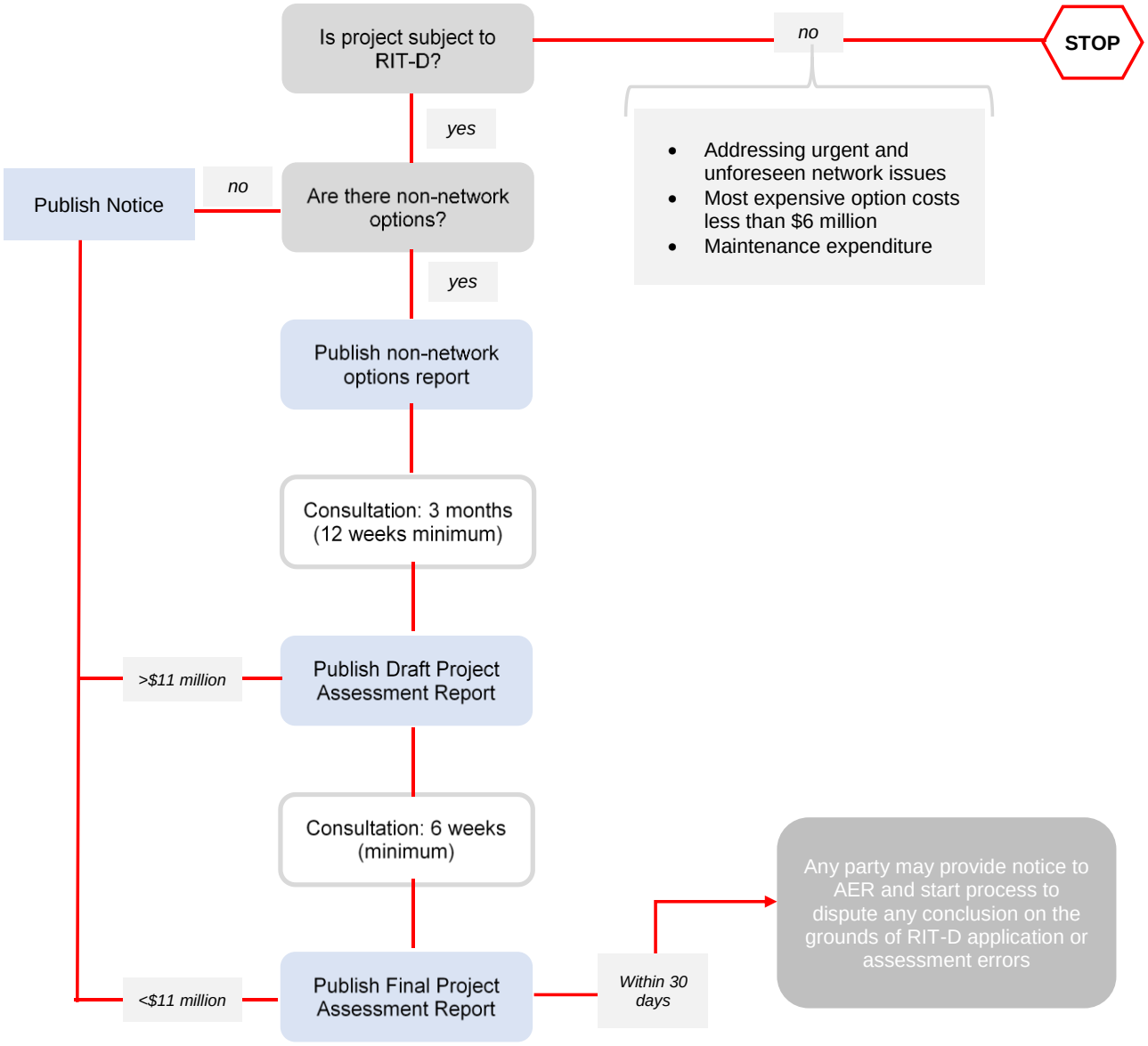
In the mid-west region large customer generation support is valued at $40-100 per kVA (excluding acquisition costs). Note that this option commonly sources existing standby generators that can be operated in parallel with the network or separated from the network in an islanded arrangement to supply the customer's facility.

Although the renewable energy projects under development in the mid-west area may possess the levels of generation support required to supply the mid-west loads, this option has been assessed as technically not viable as it is considered unlikely that these generators could supply the entire mid-west load on an enduring basis and maintain the required levels of reliability and power quality to customers in the mid-west area.

6.Conclusion

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Cape River area to address the identified need. This notice of no non-network options is therefore published in accordance with rule 5.17.4(d) of the National Electricity Rules.

Appendix A. RIT-D Process



Appendix B. Ergon Energy's Minimum Service Standards and Safety Net Targets

The legislated System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) limits from Ergon Energy's Distribution Authority are detailed in Table 5.

Feeder Category	SAIDI MSS Limits	SAIFI MSS Limits
Urban	149	1.98
Short Rural	424	3.95
Long Rural	964	7.40

Table 5 SAIDI (minutes per customer) and SAIFI (interruptions per customer) limits

The legislated Safety Net Targets from Ergon Energy's Distribution Authority are provided in Table 6. Cape River is considered a 'Rural Area'.

Area	Targets (for restoration of supply following an N-1 Event)
Regional Centre	Following an N-1 event, load not supplied must be: ○ Less than 20MVA after 1 hour; ○ Less than 15MVA after 6 hours; ○ Less than 5MVA after 12 hours; and ○ Fully restored within 24 hours.
Rural Areas	Following an N-1 event, load not supplied must be: ○ Less than 20MVA after 1 hour; ○ Less than 15MVA after 8 hours; ○ Less than 5MVA after 18 hours; and ○ Fully restored within 48 hours.
Note: All modelling and analysis will be benchmarked against 50 PoE loads and based on credible contingencies. 'Regional Centre' relates to larger centres with predominantly urban feeders. 'Rural Areas' relates to areas that are not Regional Centres.	

Table 6 Ergon Energy Service Safety Net Targets