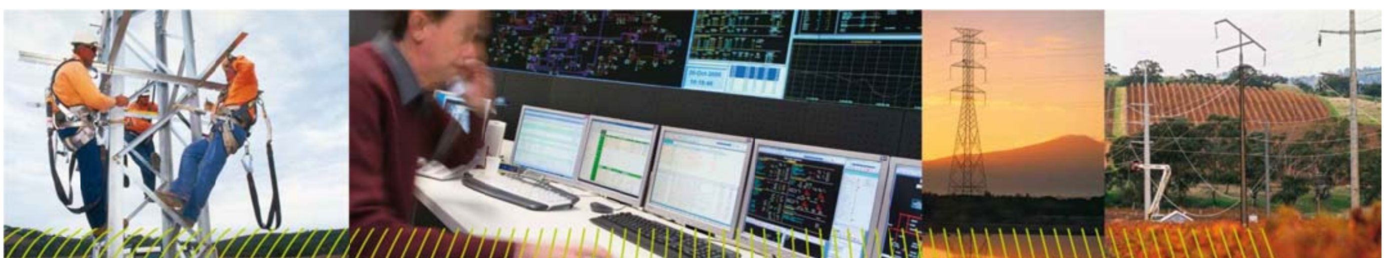
ElectraNet Transmission Network Revised Revenue Proposal

Appendix J Revised Network Project Summaries



ElectraNet Transmission Network Revised Revenue Proposal

Revised Network Project Summaries

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Version 1

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1. Kincraig Substation Replacement and Transformer Upgrade

Project Number: EC.10619 **Category:** Replacement

Estimated Cost: $36 million **Required Completion Date:** 2020

1.1 Project Requirement and Timing

The Electricity Transmission Code (ETC) lists Kincraig as a Category 4 connection point. Under the Category 4 connection point reliability requirements, Kincraig must have N-1 equivalent transmission line and transformer capacity to meet 100 per cent of the Agreed Maximum Demand (AMD). In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption.

Based on SA Power Networks 10 per cent PoE connection point forecast it is anticipated that Kincraig will be unable to meet the ETC service standards during a transformer outage during peak load times in summer 2018-19. This means that an outage of one transformer at Kincraig will overload the remaining unit in summer 2018-19. The N-1 ETC service standard requires that with the outage of one transformer, remaining units have to meet the AMD without exceeding their emergency rating. Following joint planning with SA Power Networks, it has been determined that a 33 kV 9 Mvar capacitor installed by SA Power Networks at its Naracoorte substation is the least cost solution to address the Kincraig transformer overload in summer 2018-19. This capacitor bank installation has the effect of deferring the transformer thermal overload for two years, from 2018-19 to 2020-21.

Kincraig substation was established in 1974 and is the sole source of electricity supply to the residents and businesses for a wide area ranging from Cape Jaffa to the Coonawarra and is located on ElectraNet's 132 kV South East sub-transmission network. As asset age is only an indicator of asset condition, ElectraNet uses information from condition monitoring and assessment of risk to ascertain the optimal timing of any asset replacement.

Standalone asset replacement projects are identified in ElectraNet's Asset Management Plan (AMP) 2013-2018, which establishes the framework for management of long term asset risk. A Transmission Asset Lifecycle (TALC) assessment, incorporating site / asset safety, asset capability and asset health risk analysis has been undertaken for Kincraig substation, together with an economic cost/benefit assessment. On the basis of this assessment, Kincraig substation represents an increasing reliability risk, indicating the need for asset replacement in the near term.

This project is required to meet the Rules capital expenditure objective to:

- Meet the expected demand for prescribed transmission services over the period.
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.
- Maintain the quality, reliability and security of supply of prescribed transmission services.

1.2 Option Analysis

Option	Description	Comment	Estimated PV Cost ($M)
1	Install a 33 kV 9 Mvar capacitor at SA Power Networks' Naracoorte substation followed two years later by option 2	The capacitor bank installation has been agreed at Joint Planning with SA Power Networks and allows a two year deferral of the network solution. SA Power Networks' work is costed at $1 million. This cost is accounted for in the NPV analysis. This is the lowest cost option. Hence, it is the preferred solution.	41.8
2	Rebuild Kincraig as a breaker-and-half 132 kV substation with two new 60 MVA 132/33 kV transformers	The substation configuration includes provision for a future 275/132 kV connection point 10 km west of Kincraig.	47.5
3	Rebuild Kincraig as an ultimate breaker-and-half 132 kV substation with two refurbished and one new 25 MVA 132/33 kV transformers	This option has the same advantages as Option 2, but with ultimately less transformer capacity, and at greater cost. This option has also assumed the implementation of the distribution solution applied in Option 1.	69.4
4	Rebuild Kincraig as an ultimate breaker-and-half 132 kV substation with three new 25 MVA 132/33 kV transformers	This option has the same advantages as Option 2, but with ultimately less transformer capacity, and at greater cost.	54.7
5	Non-network solution: 2 MW generation hire followed two years later by option 2	A 1 MW load reduction is required at Kincraig to delay the transformer augmentation by 12 months and 2 MW for the following year. The cost of a local generation support service is estimated at $3.6 million. This option is not the most economical means of deferring the network augmentation.	44.8

The selected option has been assessed as having the lowest PV cost of the options considered capable of addressing the identified limitation.

1.3 Project Scope

The proposed scope of works involves the following distribution works in 2018:

- Install a 33 kV 9 Mvar capacitor at SA Power Networks' Naracoorte substation

The following transmission works in 2020:

- Rebuild Kincraig at an adjacent site as a 132 kV breaker-and-half substation
- Replace the existing two 25 MVA 132/33 kV transformers, and install two 60 MVA 132/33 kV transformers and associated primary and secondary plant
- Retire the existing primary and secondary plant

2. Torrens Island Power Station 275/66 kV Transformer Update

Project Number: EC.11312 **Category:** Augmentation

Estimated Cost: $14.7 million **Required Completion Date:** 2018

2.1 Project Requirement and Timing

Torrens Island was commissioned in 1967 and supplies loads in all four metropolitan regions, particularly the west. The substation still has the majority of its original primary plant assets in service. It currently comprises two 150 MVA 275/66 kV transformers and is connected to the network via multiple 275 kV circuits from metropolitan substations.

The loads in the Western Suburbs 66 kV system are currently supplied via ElectraNet's 275/66 kV transformers at Le Fevre, Kilburn and Torrens Island substations. These three substations are listed in the ETC along with Dry Creek and New Osborne as being part of the Category 4 Western Suburbs group of exit points. Under the applicable connection point reliability requirements, Torrens Island must have N-1 equivalent transmission line and transformer capacity to meet 100 per team of Agreed Maximum Demand. N-1 is defined as the ability to continue to supply without interruption should any one element of the transmission system fail (typically an outage of a transmission line or transformer). In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption.

Based on SA Power Networks' 10 per cent PoE load forecast, and assuming low 66 kV generation output in the western suburbs, the loss of the single 225 MVA 275/66 kV Kilburn transformer will overload the two 150 MVA 275/66 kV transformers at TIPS by summer 2018-19. Therefore, augmentation of the TIPS transformers is required by November 2018 in order to comply with ETC requirements.

This project is required to meet the Rules capital expenditure objective to:

- Meet the expected demand for prescribed transmission services over the period
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services
- Maintain the quality, reliability and security of supply of prescribed transmission services.

2.2 Option Analysis

Option	Description	Comment	Estimated PV Cost ($M)
1	Replace the existing 2 x 150 MVA transformers at Torrens Island substation with 2 x 225 MVA 275/66 kV transformers	The 225 MVA size is currently adopted by ElectraNet as the minimum standard size for 275/66 kV transformers. This is the lowest cost network option. Hence, it is currently the preferred solution.	13.6

Option	Description	Comment	Estimated PV Cost ($M)
2	Install a second 225 MVA 275/66 kV transformer at Kilburn along with associated land procurement and substation reconfiguration works	This option requires ElectraNet to expand the current Kilburn site and install new GIS equipment in addition to SA Power Networks 66 kV network upgrading work, costed at an additional $6.9 million.	26.3
3	Establish new connection point at City West to supply Metro West by installing a 300 MVA, 275/66 kV transformer at City West substation	This option requires ElectraNet to install one 300 MVA 275/66 kV transformer and related new GIS equipment.	19.4
4	Establish Royal Park substation with 1 x 300 MVA 275/66 kV transformer fed by 1 x 720 MVA 275 kV cable from City West	This option is technically feasible, but it is not considered economically viable.	177.2
5	Distribution solution	Moving load to Le Fevre will overload the SA Power Networks 66 kV network between Queenstown and Woodville. This option is therefore not viable.	N/A
6	Non-network solution: Generation	This option would involve contracting sufficient generation support in the Metro west to delay the transformer upgrade until asset replacement becomes necessary. The availability and cost of this option is not known at this point. This option will be fully assessed in the project RIT-T process when the reliability cost and availability of generation support will be analysed.	N/A
7	Non-network solution: Demand side management	This option requires sufficient demand side reduction in the western suburbs to defer the transformer limitation. Based on the 10 per cent PoE load forecast, in 2017, a load reduction of 13 MW will be required to defer the project for one year. The proposed project timing has already taken into account the presence of existing Metro West embedded generation and curtailable load which has deferred the project need from 2017-18 to 2018-19.	N/A

The selected option has been assessed as having the lowest PV cost of the options considered capable of addressing the identified limitation.

2.3 Project Scope

The project will require the following:

- The replacement of the existing 2 x 275/66 kV 150 MVA units with 2 x 275/66 kV 225 MVA units
- Purchase of land on the northern side of the Torrens Island A station switchyard on the power station's car park

3. Kanmantoo Substation Upgrade

Project Number: EC.11005 **Category:** Replacement

Estimated Cost: $13 million **Required Completion Date:** 1 November 2017

3.1 Project Requirement and Timing

ElectraNet's 132/11 kV Kanmantoo Mine[1] connection point is currently assigned to Electricity Transmission Code (ETC) reliability category 1, requiring that the equivalent transformer capacity at Kanmantoo Mine must be adequate to supply the agreed maximum demand (AMD). From 1 December 2017, the single transformer, installed as an emergency replacement due to failure of the single aged unit, will no longer comply with the reliability standards of the ETC.

The substation was established in 1971 to connect the re-opened Kanmantoo Mines Ltd. copper mine. Following that mine's closure in 1976, the Kanmantoo Mine connection point became the sole source of electricity supply to the residents of the general area and, later, a fertiliser factory at Kanmantoo. The Kanmantoo Mine substation is located on ElectraNet's 132 kV Eastern Hills sub-transmission network.

As asset age is only an indicator of asset condition, ElectraNet uses information from condition monitoring and assessment within the risk management framework to ascertain the optimal timing of any asset replacement.

Standalone asset replacement projects are identified in ElectraNet's Asset Management Plan (AMP) 2013-2018, which establishes the framework for management of long term asset risk. A Transmission Asset Lifecycle (TALC) assessment, incorporating site / asset safety, asset capability and asset health risk analysis has been undertaken for Kanmantoo Mine substation, together with an economic cost/benefit assessment. On the basis of this assessment, Kanmantoo Mine substation represents a high and increasing reliability risk, indicating the need for asset replacement in the near term.

The original 5 MVA 132/11 kV transformer was swapped for one of ElectraNet's spare 10 MVA 132/33/11 kV units as an emergency change over due to its condition. This replacement transformer has a 3 MVA 11 kV loadable tertiary winding that now provides connection to SA Power Networks load customers at Kanmantoo Mine. This capacity will be reached from summer 2017/18.

Via subsequent joint planning with SA Power Networks it has been agreed that the Kanmantoo Mine 132/11 kV connection point will be replaced with a 132/33 kV connection point to properly provide for the future requirements of the region.

The switchyard is laid out in accordance with superseded standards and plant spacing such that conformance to the reliability standards mandated under NER cannot be achieved. Therefore replacement of the plant and rebuild of the bus into the required arrangement is not possible on the existing site.

[1] For historic reasons, this connection point is still known as Kanmantoo Mine substation.

ElectraNet has carried out an economic investigation into the transformer capacity standard of the Kanmantoo Mine substation consistent with the methodology applied by AEMO in its analysis supporting the Essential Service Commission of South Australia's (ESCOSA) 2010 review of the ETC reliability standards. Based on the AEMO methodology, this analysis takes into account the size of the load, the value of unserved energy and the incremental cost of the additional network assets required to achieve the increased standard of reliability.

ElectraNet has estimated that the move from Category 1 to Category 2 at this location will deliver the following customer benefits.

Reliability Standard Category	2017-18 Forecast Demand (MW)	Unserved Energy (MWhr/annum)	Annual Cost of Unserved Energy ($USE)	Project Life NPV (incremental cost)
Category 1	2.7	27	$1.22 million	
Category 2	2.7	1	$0.15 million	$4.2 million
		NPV of net unserved energy saved		$17.9 million
		NPV net benefits of augmentation		$13.7 million

As a result of this analysis, ElectraNet has written to ESCOSA recommending that the Kanmantoo Mine substation be reclassified to an ETC Category 2 reliability standard. Public consultation on this proposal has commenced and is anticipated to conclude in March 2013. ElectraNet anticipates that the decision in the final determination in March will be to move Kanmantoo Mine substation to ETC category 2 and the following options are presented on this basis.

Consistent with the 10 per cent PoE demand forecasts, the completion of this project is now required by the summer of 2017-2018. It has therefore been proposed that the reclassification of this exit point should take effect from 1 November 2017.

This project is required to meet the Rules capital expenditure objective to:

- Meet the expected demand for prescribed transmission services over the period.
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.
- Maintain the quality, reliability and security of supply of prescribed transmission services.

3.2 Option Analysis

Option	Description	Comment	Estimated PV Cost ($M)
1	Rebuild the existing substation on an adjacent site with 2 x 10 MVA 132/33 kV transformers	This is the only option considered technically viable because it improves the reliability of the substation on an economic basis, avoids lengthy supply outages during construction and fully addresses the very poor asset condition. As above, the incremental cost of the second transformer was found to be outweighed by the level of unserved energy avoided, which delivered an additional benefit of $13.7 million based on NPV analysis.	13
2	Rebuild the existing substation in situ with 2 x 10 MVA 132/33 kV transformers	This option is considered impractical because it would involve the complete disconnection of the entire load during the construction. Also, solution is not considered to be technically feasible because of the space constraints at this site.	N/A
3	Non-network solution: Generation / demand side management	A 3 MW generation support is required at Kanmantoo to delay the transformer augmentation by 12 months. The cost of a local 3 MW generation support service is estimated at $5.4 million. This is not economically effective in deferring the network augmentation by 1 year.	N/A
4	Do nothing	This option is not considered a viable alternative because it does not address the condition of the assets nor the implications on the electricity supply to the wider Kanmantoo area in the event of an asset failure.	N/A

The selected option has been assessed as having the lowest PV cost of the options considered capable of addressing the identified limitation.

3.3 Project Scope

The proposed scope of works involves:

- Rebuild Kanmantoo on an adjacent site as a mesh bus substation.
- Install 2 x 10 MVA 132/33 kV transformers (one new and one presently installed) and associated primary and secondary plant.
- Retire the existing primary and secondary plant.

4. Mount Barker Second 225 MVA 275/66 kV Transformer

Project Number: EC.11625 **Category:** Connection

Estimated Cost: $10.2 million **Required Completion Date:** 2020

4.1 Project Requirement and Timing

Mount Barker South substation was established in 2011 and supplies electricity, along with the Mount Barker substation, to the Adelaide Hills and the surrounding districts. It is located in the Eastern Hills region on the 275 kV transmission network between Cherry Gardens and Tungkillo and currently comprises a single 225 MVA 275/66 kV transformer.

The ETC groups Mount Barker and Mount Barker South into a combined Category 4 connection point. Under Category 4 connection reliability requirements, Mount Barker and Mount Barker South must jointly provide N-1 equivalent transmission line and transformer capacity to meet 100 per cent of the Agreed Maximum Demand (AMD). In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption.

Based on SA Power Networks' 10 per cent PoE connection point demand forecast, it is forecast that the Mount Barker substation will be unable to meet the ETC service standards by the summer of 2020-21. Specifically, it is forecast that the contingent loss of the existing single 225 MVA 275/66 kV Mount Barker South transformer at 10 per cent PoE peak load times will result in thermal overloading of the two 60 MVA 132/66 kV transformers at Mount Barker.

This project is required to meet the Rules capital expenditure objective to:

- Meet the expected demand for prescribed transmission services over the period
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services

4.2 Option Analysis

Option	Description	Comment	Estimated PV Cost ($M)
1	Install a second 275/66 kV 225 MVA transformer at Mount Barker South in 2020/21	This is considered a viable and cost effective solution. Mount Barker South will have 2 x 225 MVA transformers, and the existing 132 kV Mount Barker substation will ultimately be retired in addition to SA Power Networks 66 kV network upgrading work, costed at an additional $6 million. This is the lowest cost option. Hence, it is the preferred solution.	16.5
2	Install a third 132/66 kV 60 MVA transformer at Mount Barker substation and replace the existing transformers	This is not considered a viable or cost effective solution. This requires a new transformer and a complete site rebuild at Mount Barker substation due to the existing equipment spacing, age and condition of relevant 132 kV assets.	21.4
3	Distribution solution	Load transfer options were investigated with SA Power Networks but the proposed configuration did not meet SA Power Networks' protection requirements and proved technically unviable.	N/A
4	Non-network solution: Generation	A 6 MW load reduction in 2020/21 is required to delay network augmentation by 12 months. The cost of a typical 2 MW generation support service is estimated at $3.6 million. This expenditure is an uneconomical means of deferring the network augmentation for any length of time.	N/A
5	Non-network solution: Demand Side Management	Demand reduction of 6 MW would be required in the Mount Barker region to defer network reinforcement by 12 months. Preliminary advice from SA Power Networks indicates that there are only 6 customers on the Eastern Hills with peak demand in excess of 500 kVA, with an aggregate peak load of 7.7 MVA and that the required demand is unlikely to be achievable. Hence, DSM is not expected to be a viable solution for this network constraint. However, this will be investigated further as part of the RIT-T process for this project.	N/A

The selected option has been assessed as having the lowest PV cost of the options considered capable of addressing the identified limitation.

4.3 Project Scope

The proposed scope of works involves:

- install a second 275/66 kV 225 MVA transformer at Mount Barker South Substation

- retire the Mount Barker 132 kV substation

5. Unit Asset Replacements 2013 -2018

Project Number: EC.11890 **Category:** Replacement

Estimated Cost: $32.3 million **Required Completion Date:** 1 July 2017

5.1 Project Requirement and Timing

Unit asset replacements involve individually targeted in situ replacements of substation assets, including circuit breakers, voltage transformers, current transformers and protection relay sets. The nominated assets are located at a variety of specified locations on ElectraNet's 66 kV, 132 kV and 275 kV networks on a prioritised basis.

These are predominately assets that are unreliable, are known to have a high failure history and represent a safety risk, or are at the end of their effective technical lives as the cost of maintenance outweighs the replacement value of the asset. The scope of this project includes only those assets that will not be replaced as part of an augmentation project or major substation rebuild projects scheduled in the foreseeable future. It is also limited to those assets that have been assessed as requiring replacement prior to the end of the regulatory period based on the assessed asset condition and risk. These assets will need to be replaced prior to the end of the regulatory period in order to mitigate safety risk, minimise maintenance effort and cost and to ensure the mandated levels of system reliability are maintained.

The required completion date ensures the replacements are completed in the forthcoming regulatory period. The individual replacements are prioritised according to those asset types that are known to have a high failure history. Unit asset replacements assessed as being of lesser priority based on condition and risk will be targeted for completion in following periods.

The project has been scoped on the basis of itemised substation assets identified through the transmission asset life cycle (TALC) assessment process at the equipment type (or component) level within the overall asset management framework. The cost estimates are derived from ElectraNet's established project cost estimating process, with the cost of individual components based on documented external information, and installation and other costs established from ElectraNet's experience of delivering similar unit asset replacements in the current regulatory period.

This project is required to meet the Rules capital expenditure objective to:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

5.2 Option Analysis

Option	Description	Comment
1	Replace asset classes assessed as having a high risk of affecting system reliability	This option is the optimal technical and economic solution for the assets involved. It minimises the corrective maintenance cost and effort and allows a properly planned approach to the replacement of high risk asset classes prior to their failure to minimise the impact this has on system reliability.
2	Replace individual items of plant based on an ad hoc basis	This option produces a similar result to the do nothing option considered below. It does not effectively address the increased corrective maintenance costs and the impact on the reliability of the network that these asset classes pose at a network level, even though individual assets are replaced. Further, other cost impacts resulting from maintainability, spares holdings, technical capability, technical support and the like are not addressed. This option is not considered to be viable or economic.
3	Do nothing	This option will expose ElectraNet to increased safety risks and reliability issues. As these assets are at the end of their technical life there is increased risk of catastrophic failure, which could lead to injury of personnel working within the substation. If this option was selected, failure of assets during the regulatory period will result in higher than planned corrective operational expenditure and the unplanned unavailability of parts of the network. This option is not considered to be viable or economic.

The selected option has been assessed as being the only one of the options considered that is capable of addressing the identified limitation.

5.3 Project Scope

The proposed works include:

- Replace the identified circuit breakers, isolators, capacitive voltage transformers, voltage transformers, current transformers at individually specified sites across the 66kV, 132kV and 275kV transmission network;
- Replace the identified protection relays at individually specified sites across the 66kV, 132kV and 275kV transmission network.