ElectraNet Transmission Network Revenue Proposal

Appendix P – Forecast Network Capital Projects

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1. Introduction

ElectraNet's capital expenditure forecast for the 1 July 2013 to 30 June 2018 regulatory period is presented in Chapter 5 of ElectraNet's Revenue Proposal, which also includes a description of the methodology and key inputs and assumptions used to develop the capital expenditure forecast.

The Submission Guideline templates accompanying the Revenue Proposal include a full list of the capital projects included in the capital expenditure forecast.

This appendix includes project summaries for augmentation, connection and replacement network projects involving expenditure of greater than $10 million in the forthcoming regulatory period[1].

The project summaries include:

- Details of the project requirement and timing including the Rules capital expenditure objectives(s) that the capital project is required to meet;
- The alternative options considered to address the limitation; and
- A description of the project.

While the project summaries include a high level comparison of the selected project with alternative options considered, they are not intended to include a detailed present value analysis of the alternative options.

1 Values are quoted in ($2012-13) consistent with the information reported in the Submission Guideline templates

2. Waterloo Substation Replacement

Project Number: EC.10503 **Category:** Connection and Replacement

Estimated Cost: $39.5m **Required Completion Date:** 2013

2.1 Project requirement and timing

Waterloo substation was established in 1953 and is the sole source of electricity supply to a wide area ranging from Riverton to Auburn and Robertstown. Connected to four 132 kV transmission lines from Robertstown, Mintaro, Hummocks and Templers, Waterloo is a key 132 kV transmission node in the Mid-North region. Under single contingency operating conditions, it is required to supply the entire Yorke Peninsula or Barossa areas and also to support the Riverland.

The substation currently comprises a meshed 132 kV bus and two 10 MVA 132/33 kV fixed-tap transformers and two 10 MVA 33 kV regulators supplying into a 33 kV distribution system owned by ETSA Utilities.

The Electricity Transmission Code (ETC) listed Waterloo as a Category 4 connection point, as of 1 January 2010. This standard requires ElectraNet to have in place N-1 equivalent transmission line and transformer capacity to meet 100% of Agreed Maximum Demand (AMD). 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.

Following the construction and commissioning of the new connection point at Clare North in December 2010, loading on the Waterloo connection point was significantly reduced, achieving compliance with the requirements of ETC Category 4 reliability standards with the existing transformers and substation equipment.

However, by the summer of 2012-13, the transformer capacity at Waterloo substation will no longer comply with the ETC service standards. Specifically, it is forecast that the contingent loss of a single connection point transformer will result in thermal overloading of the remaining unit, ultimately disconnecting the entire load.

Asset replacement projects are identified in ElectraNet’s Asset Management Plan (AMP), which establishes the framework for management of long-term asset risk. A detailed condition assessment and asset replacement risk analysis has been undertaken for Waterloo substation. The majority of assets at this site have been identified as being in poor condition. On the basis of this assessment, Waterloo Substation represents an increasing reliability risk, indicating a need for replacement in the near term.

The timing of this replacement is being staged to coincide with the reinforcement requirement outlined above in order to maximise efficiency and minimise long-run cost.

This project is required to meet the Rules capital expenditure objectives to meet the expected demand for prescribed transmission services over the period, to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

2.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Rebuild the Waterloo substation on an adjacent site and install 2 x 25 MVA 132/33 kV transformers	The project can be completed before the end of the year 2013. This is the preferred option as it represents the lowest overall cost.	24.1
2	Install a third 10 MVA 132/33 kV transformer in the existing Waterloo substation	The condition of the primary plant, the transformers and the regulators preclude this option from being viable. Therefore it has not been costed as a complete in-situ rebuild and three new transformers would be required, which is clearly a more costly option.	N/A
3	Distribution solution (including power factor improvement)	This is not a viable option as it doesn't address the condition of the site and the reliability risks that it presents. In addition, load power factors are already compliant with connection agreement and NER thresholds and there is no additional benefit of improving them further.	N/A
4	Non-network solution: Generation	This is not a viable option as it does not address the condition of the site and the reliability risks that it presents.	N/A
5	Non-network solution: Demand side management	This is not a viable option as it does not address the condition of the site and the reliability risks that it presents.	N/A
6	Do nothing	This is not a viable option as it does not address the ETC reliability standards or the condition of the site and the reliability risks that it presents.	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 proposed scope of works involves:

- Rebuild Waterloo at an adjacent site as a 132 kV breaker-and-half substation.
- Replace the existing two 10 MVA 132/33 kV transformer and regulator pairs, and install two 25 MVA 132/33 kV transformers and associated primary and secondary plant.
- Retire the existing primary and secondary plant.

3. Baroota Substation Rebuild

Project Number: EC.10618

Category: Connection

Estimated Cost: $17.5m

Required Completion Date: 2017

3.1 Project requirement and timing

Baroota substation was established in 1971 and is supplied via one 132 kV transmission line from Bungama. The substation presently comprises a minimalist 132 kV bus and single 10 MVA 132/33 kV transformer supplying into a 33 kV distribution system owned by ETSA Utilities.

The ETC assigns Baroota connection point to a Category 1 reliability level until 1 December 2017. To date this reliability standard has only obligated ElectraNet to provide system normal transmission line and transformer capacity with no requirement for any redundancy.

From 1 December 2017, the ETC reassigns the Baroota connection point to a Category 2 reliability level. This standard requires ElectraNet to have in place N equivalent transmission line and N-1 equivalent transformer capacity to meet 100% of the 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 capacity within two days of the interruption and N equivalent transformer capacity within eight days of the interruption.

A condition assessment conducted for this site indicates that the majority of the primary equipment is in poor condition and that the existing 132 kV ganged interrupter and fuse arrangement is both out-dated and poses a safety hazard. Most of the secondary equipment is also in average to poor condition and the overall switchyard, plant layout and equipment are not in accordance with current ElectraNet design standards or good electricity industry practice. The substation is therefore in need of replacement.

The existing Baroota substation is located in a future road easement owned by the State Government. For this reason, it is necessary to rebuild on an adjacent site.

This project is required to meet the Rules capital expenditure objectives to meet the expected demand for prescribed transmission services over the period, to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to 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 Baroota substation at a nearby site to include one 10 MVA 132/33 kV transformer and one 25 MVA 132/33 kV transformer	The existing 10 MVA 132/33 kV transformer is re-used as one of the transformers at the new site, in parallel with a new 25 MVA 132/33 kV unit. Replacement of the smaller transformer is required in time once load growth exceeds capacity. This is the least cost option of those identified that eliminate the identified constraint and is the preferred option.	15.8
2	Rebuild Baroota substation at a nearby site to include two 10 MVA 132/33 kV transformers	The existing 10 MVA 132/33 kV transformer is re-used as one of the transformers at the new site, in parallel with a new 10 MVA 132/33 kV unit. Replacement of both transformers is required in time once load growth exceeds capacity. This option is not preferred due to its higher cost and shorter term outlook	15.9
3	Rebuild Baroota substation at a nearby site to include two new 25 MVA 132/33 kV transformers	The existing 10 MVA 132/33 kV transformer is relocated to ElectraNet's spares holding. This option is not preferred due to its higher cost.	15.9
4	Distribution solution (including power factor improvement)	There is no available distribution load transfer that can resolve this constraint. Also, power factor correction cannot assist in meeting the ETC requirement; hence, this is not a viable option	N/A
5	Non-network solution: Generation	Generation is not capable of meeting the reliability standard required by the ETC from 1 December 2017; hence, this is not a viable option	N/A
6	Non-network solution: Demand side management	Demand side management cannot address the increased reliability requirement required by the ETC; hence, this is not a viable option	N/A

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

3.3 Project scope

The proposed scope of works involves:

- Rebuilding the Baroota Substation at a nearby site.
- Installation of one 132/33 kV 25 MVA transformer and one 10 MVA (relocated from the existing site).

- Installation of associated switchgear including one 132 kV circuit breaker and two 33 kV circuit breakers on the low side of the transformers.
- Decommissioning, removal of assets and remediation of the existing site.

4. Kincraig Substation Replacement and Transformer Upgrade

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

Estimated Cost: $41.3m **Required Completion Date:** 2017

4.1 Project requirement and timing

Kincraig substation was established in 1974 and is the sole source of electricity supply to a wide area ranging from Cape Jaffa to the Coonawarra, and is located in the South East region. The substation consists of two 25 MVA 132/33 kV transformers and is supplied via 132 kV lines from the Keith and South East substations.

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

It is forecast that Kincraig will no longer comply with the ETC service standards from 2017-18. Specifically, it is forecast that the contingent loss of a single transformer at Kincraig will result in thermal overloading of the remaining unit, ultimately disconnecting the entire load.

Asset replacement projects are identified in ElectraNet's AMP, which establishes the framework for management of long-term asset risk. A detailed condition assessment and asset replacement risk analysis has been undertaken for Kincraig substation. The majority of assets in the site have been identified as being in poor condition. On the basis of this assessment, Kincraig Substation represents an increasing reliability risk, indicating a need for replacement in the near term.

The timing of this replacement is being staged to coincide with the reinforcement requirement outlined above in order to maximise efficiency and minimise long-run cost.

This project is required to meet the Rules capital expenditure objectives to meet the expected demand for prescribed transmission services over the period, to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

4.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	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 west of Kincraig. This is the preferred option as it represents the lowest overall cost.	32.3

Option	Description	Comment	Estimated PV Cost ($m)
2	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 1, but with ultimately less transformer capacity, and at greater cost.	34.8
3	Distribution solution	ETSA Utilities is evaluating non-network solutions for Keith – Bordertown constraints enabling deferral of the need to upgrade the Keith connection point. This option involves the installation of up to 4 MW of embedded generation at or near the Bordertown substation in 2013 and completion of various distribution network upgrades and distribution load transfers. This approach maximises the deferral of the transmission reinforcement by use of distribution solutions. No further distribution deferral is expected to be viable in this part of the network. In addition, this option does not address the condition of the assets.	N/A
4	Non-network solution: Generation / demand side management	A 0.8 MW load reduction is required at Kincraig to delay the transformer augmentation by 12 months. The cost of a local 1 MW generation support service is estimated at $2.1 million. This is an uneconomical means of deferring the network augmentation by one year. In addition, this option does not address the condition of the assets.	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:

- 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.

5. Para SVC Secondary Systems Replacement Stage 2

Project Number: EC.10703 **Category:** Replacement

Estimated Cost: $16.6m **Required Completion Date:** 2017

5.1 Project requirement and timing

Para substation was established in 1969 and is a major component of the electricity supply to the Northern suburbs and is also a key strategic node in the 275 kV main grid transmission network. The two SVCs at Para were installed as part of the interconnection with Victoria in 1988-89 and are necessary to achieve import and export across the South East to Heywood (Victoria) 275 kV interconnection circuits. The reliability of the SVCs directly affect the operation of this interconnector and the level of available transfer capacity.

The ETC lists Para as part of the grouped Category 4 connection point that supplies the Northern suburbs of Adelaide. Under Category 4 connection reliability requirements, Para must have N-1 equivalent transmission line and transformer capacity to meet 100% of Agreed Maximum Demand. In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption and to use its best endeavours to restore N-1 equivalent line capacity as soon as practicable after the commencement of the interruption.

The primary plant associated with the SVCs is estimated have an effective remaining life of around fifteen years. However, on the basis of asset condition, the secondary control system is deemed to be at the end of its effective life, due to a number of factors:

- The availability of spare parts is dwindling, and several key components of the control boards are beginning to fail;
- The lack of ability to remotely interrogate the controls hinders event investigation and the age and style of the system makes it difficult and costly to update any applied program; and
- The limited ability due to programming difficulties and the lack of available ports to integrate the SVC into an overall, wide area voltage control scheme.

It is therefore considered that in order to maintain the reliability of the SVCs for their remaining life, replacement of the control system and associated plant is required.

This project will complete the staged replacement of the SVC secondary systems on the network, involving:

- Replacement of the South East SVC Control and Protection Systems in the current regulatory period;
- Recovery of equipment from the South East SVC Controls to provide a pool of spares for the Para SVCs; and
- Replacement of Para SVC Control and Protection Systems in the forthcoming regulatory period.

This project is required to meet the Rules capital expenditure objectives to meet the expected demand for prescribed transmission services over the period, to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

5.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Staged installation of new thyristor valves, valve cooling, control and protection control systems to replace the two existing systems at Para.	This is the only option considered technically viable because it stages the replacement of the assets that are in need of replacement at Para. This option is recommended as it provides a scope of work broad enough to allow competitive tendering for all or part of the project if separable portions are defined.	16.6
2	Install new control systems to replace one or more control systems	This option is considered impractical because modern control systems also have a different thyristor valve operating system and not all the benefits of installing a new control system would be realised. This option is not considered further.	N/A
3	Install new components to replace components approaching end of life	This option is not available as the current control system technology is out dated and no longer in production. The cost of having the original equipment manufacturer produce new components for the existing system would be greater than completely replacing the existing system. In addition this would not deliver the improved remote accessibility incorporated into new systems. This option is not considered further.	N/A
4	Do nothing	This option is not considered a viable alternative because it does not address the increased risk of the SVC control system reaching end of life and the unavailability of off the shelf new printed circuit boards to repair any failures within the existing system. Operational issues will result should both SVCs at Para be unavailable at the same time. This option is not considered further.	N/A

5.3 Project scope

The proposed scope of works involves:

- Supply and install new thyristor valves, valve cooling systems, control systems and protection systems at Para Substation SVCs.
- Supply a new training simulator and associated equipment.

6. Kanmantoo Substation Upgrade

Project Number: EC.11005

Category: Replacement

Estimated Cost: $14.3m

Required Completion Date: 2016

6.1 Project requirement and timing

Kanmantoo substation was established in 1971, is located in the Eastern Hills region, and is the sole source of electricity supply to the surrounding area. It currently comprises a single 10 MVA 132/33/11 kV transformer and is connected to the network via a radial 132 kV line from the Mobilong No 3 Pumping Station.

The ETC lists Kanmantoo as a Category 1 connection point. This reliability standard requires that Kanmantoo must have N equivalent transmission line and transformer capacity to meet 100% of Agreed Maximum Demand. In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line capacity within two days or N equivalent transformer capacity within 8 days of the interruption.

The original 5 MVA 132/11 kV transformer was swapped for a spare 10 MVA 132/33/11 kV unit as an emergency change-over in 2011 due to its condition. This replacement transformer has a 3 MVA 11 kV loadable tertiary winding that now provides connection to ETSA Utilities load customers at Kanmantoo. The capacity of this transformer will be exceeded from summer 2016-17. Via joint planning with ETSA Utilities it was agreed that the Kanmantoo 132/11 kV connection point would be replaced with a 132/33 kV connection point to provide for the future requirements of the region.

Asset replacement projects are identified in ElectraNet's AMP, which establishes the framework for management of long-term asset risk. A detailed condition assessment and asset replacement risk analysis has been undertaken for Kanmantoo substation. This found Kanmantoo substation to be of high and increasing reliability risk associated with the bulk oil circuit breakers, indicating a need for replacement in the near term. In addition, the switchyard is laid out in accordance with old standards that do not conform to the Rules.

The timing of this replacement is being staged to coincide with the reinforcement requirement outlined above in order to maximise efficiency and minimise long-run cost.

This project is required to meet the Rules capital expenditure objectives to meet the expected demand for prescribed transmission services over the period, to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

6.2 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 option considered to deliver the highest net benefit because it improves the reliability of the substation, avoids lengthy supply outages during construction and it fully addresses the very poor asset condition. The incremental cost of the second transformer was found to be outweighed by the unserved energy reduction, which delivered an additional benefit of approximately $11m based on high level NPV analysis	13
2	Rebuild the existing substation on an adjacent site with 1 x 10 MVA 132/33 kV transformer	This option was found to be inferior to the establishment of a dual transformer substation as the capital cost saving of a single transformer was outweighed by the level of additional unserved energy relative to Option 1, based on high level NPV analysis	10
3	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 for the duration of the construction period. This option is not considered further.	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 reliability requirements of the ETC.	N/A

6.3 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.

7. Cultana 275/132 kV Augmentation

Project Number: EC.11101

Category: Augmentation

Estimated Cost: $71.8m

Required Completion Date: 2014

7.1 Project requirement and timing

Cultana substation was established in 1989, is located in the Eyre Peninsula region, and is the sole source of electricity supply to the entire Eyre Peninsula and Far West region. It currently comprises a single 160 MVA 275/132 kV transformer and is connected to the network via a radial 275 kV line from the Davenport substation.

The Rules require ElectraNet to comply with the power system performance and quality of supply standards in schedule 5.1.

The Whyalla Central connection point, which is supplied from Cultana substation, is classified as a Category 4 exit point. This requires that the Cultana substation must also meet the Category 4 reliability requirements detailed in the ETC. This requires that Cultana must have N-1 equivalent transmission line and transformer capacity to meet 100% of Agreed Maximum Demand. In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption.

The ETC also requires that ElectraNet plan, develop and operate the transmission network such that there will be no requirements to shed load in order to achieve the standards of the Rules under normal and reasonably foreseeable operating conditions.

Under the demand forecasts provided by ETSA Utilities and direct connect customers, the reliability requirements of the ETC cannot be met by the installed transmission infrastructure alone from 2009.

Power transfer at times of high load on the Eyre Peninsula, is becoming increasingly difficult to manage under single contingency operating conditions. The issue is one of maintaining adequate and stable voltages at the extremities of the network (Port Lincoln and Wudinna) when either the Cultana 275/132 kV transformer or the Davenport to Cultana 275 kV transmission line is out of service. An unplanned outage at times of high load would result in 132 kV voltages below the minimum standards specified in the Rules and the potential for voltage collapse and disconnection of the entire 132 kV network supplied from Playford (Davenport).

In addition, by the summer of 2012-13, when either the Cultana 275/132 kV transformer or the Davenport to Cultana 275 kV transmission line is out of service, the voltage fluctuations on the Whyalla Terminal 33 kV main bus connection point with ETSA Utilities and the Middleback 132 kV connection point with OneSteel will exceed the emission limits allowed in Table 7 of AS/NZS 61000.3.7.2001 and specified in the Rules, representing a quality of supply issue.

Finally, a recent aerial laser survey of the two river crossing spans on the 132 kV Davenport to Cultana lines have a potential low clearance violation due to the 49°C design standard these assets were built to. This means that at peak summer temperatures, the lines may not be able to provide the required transfer capacity without breaching the minimum statutory height standards for a shipping lane. This requires the lines to be deenergised under peak summer temperature and loading conditions, meaning that Cultana will not comply with the reliability standard required by Category 4 of the ETC under these conditions and with the present arrangement of the 275 kV network in the area.

The voltage limitations identified above have already been deferred for some years by a combination of reactive support (Port Lincoln 33 kV Capacitor Banks) and system normal dispatch of the contracted Port Lincoln generation at times of high load (generation that is contracted in any case to provide network support to meet the ETC reliability standards at Port Lincoln).

More detailed descriptions of the limitations were discussed in the Regulatory Test Final Report, "New large Network Asset – Cultana Augmentation", published by ElectraNet in March 2011 in accordance with the Regulatory Test public consultation 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 and maintain the quality, reliability and security of supply of prescribed transmission services.

7.2 Option Analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Create two Cultana to Whyalla 132 kV circuits by turning Playford to Whyalla #2 into Cultana; supply Yadnarie radially from Cultana by turning Playford to Whyalla #1 into Cultana; break out the second Davenport to Cultana 275 kV circuit; install a second 200 MVA 275/132 kV transformer at Cultana; turn back the Playford to Cultana 132 kV circuits at the Cultana end	This is the lowest cost and most reliable option. The project is on schedule to be completed before the end of the year 2013.	54.4
2	Increase use of existing network support arrangement at Port Lincoln Terminal, install an SVC at Port Lincoln Terminal 33 kV, bring both Davenport to Whyalla 132 kV transmission lines into Cultana and up-rate the 132 kV transmission lines over Spencer Gulf crossing	This option is significantly more expensive and does not improve the supply reliability to the Eyre Peninsula to the same extent.	79.2
3	Increase size and use of the network support arrangement at Port Lincoln Terminal substation and up-rate 132 kV transmission lines over Spencer Gulf crossing	This option is more expensive and does not improve the supply reliability to the Eyre Peninsula to the same extent.	64.7

Option	Description	Comment	Estimated PV Cost ($m)
4	Generation	The running of the existing generation connected at Port Lincoln Terminal to address the aforementioned voltage issue also assists in keeping the voltage fluctuations below the emission limits specified in AS/NZS 61000. However, post 2012-13, as the load increases, this solution does not prevent the emission limits from being exceeded.	N/A
5	Load side power factor improvement	The load power factors are already compliant with the connection agreement and Rules thresholds and there is no additional benefit of further improvement.	N/A
6	Demand Side Management (DSM)	Any DSM schemes at the distribution level are incorporated into the ETSA Utilities AMD. ElectraNet is currently unaware of any suitably sized loads that could off-load the network enough to prevent this quality of supply issue.	N/A
7	Permanent or rapid automatic Distribution load shift	No alternative distribution systems exist.	N/A
8	Do nothing	This is not considered a viable alternative as it does not address the Rules quality of supply issue.	N/A

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

7.3 Project Scope

The proposed works include:

- Undertake the 275 kV Cultana exit works at Davenport at the same time as the Playford relocation project.
- Develop the 132 kV section at Cultana.
- Reinforce Cultana with a second 200 MVA 275/132 kV transformer and break out the second Davenport to Cultana 275 kV transmission line.

8. Munno Para 275/66 kV Substation

Project Number: EC.11209

Category: Connection

Estimated Cost: $42.6m

Required Completion Date: 2014

8.1 Project requirement and timing

The loads in the 66 kV system that services the Northern Suburbs of Adelaide are currently supplied via ElectraNet's 275/66 kV transformers at Para and Parafield Gardens West substations.

Under ETC Category 4 connection point reliability requirements, Para must have N-1 equivalent transmission line and transformer capacity to meet 100% of Agreed Maximum Demand. In the event of an interruption, the ETC requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption.

The new ETC lists the Munno Para substation as part of this group of exit points. In the event of an interruption, the ETC also requires ElectraNet to restore N equivalent line or transformer capacity within 12 hours of the interruption.

Under the demand forecasts provided by ETSA Utilities, the exit point reliability requirements of the ETC may not be met by the existing installed grouped transformer capacity from as early as 2014.

Furthermore, significant limitations have emerged on the underlying distribution network. In particular, the Parafield Gardens West to Parafield Gardens 66 kV line will overload when there is an outage of the Parafield Gardens West to Paralowie 66 kV line during forecast peak summer load times.

Further information on the network constraints and the solution selected is available in the Evaluation Report RFP-ER 008/06 published jointly by ETSA Utilities and ElectraNet in accordance with the Regulatory Test public consultation requirements in the Rules in October 2007.

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 and maintain the quality, reliability and security of supply of prescribed transmission services.

8.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Distribution network development followed by Munno Para	This option involves the construction of a new 66 kV circuit from Parafield Gardens West to Parafield Gardens followed by the establishment of a joint use Munno Para 275/66 kV connection point. This was the preferred option identified in the Regulatory Test	30.1
2	Distribution network development	This option involves the construction of a second 66 kV circuit from Parafield Gardens West to Parafield Gardens followed by installing 2 x 225 MVA 275/66 kV transformers at Para and the construction of a 66 kV circuit from Para to Penfield in 2014. This option was discarded as being a higher cost solution than a transmission injection point	32.6
3	Alternative distribution network development followed by Munno Para	This option involves the construction of a new 66 kV circuit from Parafield Gardens West to Salisbury followed by the establishment of a joint use Munno Para 275/66 kV connection point in 2015. This option was discarded as it was a higher cost option than the previous option	34.2
4	Non-network solution: Generation	For a generation option to meet the ETC reliability standard it would have to be dispatched whenever the long-time emergency cyclic rating of the smallest transformer in the Para system would be exceeded by a network contingency in anticipation of a transformer failure. No feasible generation options were identified in the Regulatory Test assessment.	N/A
5	Permanent or rapid automatic distribution load shift	No alternative distribution switching options exist to address the network capacity limitations identified by ETSA Utilities. Therefore this option is not considered to be a viable alternative	N/A
6	Non-network solution: Demand side management	The only DSM alternative that could meet ETSA Utilities requirements would require contracting load to be disconnected at all times the loading on the network results in the identified capacity limitations. No feasible demand side options were identified in the Regulatory Test assessment.	N/A
7	Do nothing	This option does not address the network capacity limitations identified by ETSA Utilities or the reliability requirements of the ETC and is therefore not considered to be a viable alternative	N/A

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

8.3 Project scope

The proposed works include:

- Construction of a second 66 kV line from Parafield Gardens West to Parafield Gardens and to rebuild the Elizabeth South to Penfield 66kV line with larger conductor.
- Establishment of a new 275/66 kV Transmission Connection Point substation comprising one 225 MVA 275/66 kV transformer at Munno Para and associated works.

9. East Terrace Second Transformer

Project Number: EC.11210

Category: Connection

Estimated Cost: $23.2m

Required Completion Date: 2017

9.1 Project requirement and timing

East Terrace substation was established in 1974, is located in the Adelaide Central region, and is one of two sources of electricity supply to the Adelaide CBD. It currently comprises a single 225 MVA 275/66 kV transformer and is connected to the network via a radial 275 kV cable from the Magill substation.

The new ETC categorises the Adelaide Central Region (ACR) grouped exit point, which comprises the East Terrace and City West connection points, as a Category 5 exit point.

Since 31 December 2011, ElectraNet has been required to provide N-1 equivalent capacity into ACR for at least 100% of Agreed Maximum Demand on a continuous basis by means of independent and diverse transmission substations. In the event of an interruption, the ETC requires ElectraNet to use its best endeavours to restore 100 % equivalent line and transformer capacity into the ACR as soon as practicable after the commencement of the outage.

Under N-1 conditions, the East Terrace substation must supply the entire ACR load during loss of either the City West transformer or the TIPS to City West 275 kV cable. The existing East Terrace transformer’s summer cyclic loading limit has been assessed as 270 MVA.

Based on the 2012 load forecast supplied by ETSA Utilities, the load for the ACR will exceed the capacity of the East Terrace transformer in 2017-18. The East Terrace substation will therefore fail to satisfy the ETC since it will be unable to supply the ACR under the contingency of the loss of the City West to TIPS 275 kV cable or the City West – ACR transformer.

In order to address this network limitation and satisfy the requirements of the ETC, it is necessary to provide additional equivalent transformer capacity at East Terrace before the end of 2017.

This project is required to meet the Rules capital expenditure objective to meet the expected demand for prescribed transmission services over the period and comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

9.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Install a second 225 MVA transformer at East Terrace substation with a Neutral Earthing Reactor (NEX) at East Terrace Substation and Magill Substation.	This is the lowest cost option. The project can be completed before the end of the year 2017. The protection constraint on the Magill to East Terrace 275 kV cable also needs to be removed.	23.6
2	Replace existing 225 MVA transformer at East Terrace substation with a 300 MVA transformer with NEXs at East Terrace Substation and Magill Substation	The 66 kV ETSA Utilities network was designed and built for connection to a maximum transformer size of 225 MVA. Installation of a 300 MVA transformer will require upgrade of the distribution network. The replacement can only be done by installing the 300 MVA on land adjacent to the existing transformer and then removing the existing 225 MVA. This option is discounted because the transmission cost is greater than in option 1, ultimately with less capacity.	29 (transmission component)
3	Construct a single circuit 275 kV line from East Terrace substation to City West substation, and install a 66 kV bus at City West substation	This option is technically feasible, but it is an expensive option. Timing is also a constraint. It is not possible for ElectraNet to complete the cable works before the end of 2017. This option is discounted because of its cost.	71.4
4	Distribution solution	This network reinforcement is an ETC compliance requirement. In the ETC, it is clearly stated that the ACR is a Category 5 load and that N-1 transformer capacity has to be provided by a transmission substation. Unity power factor is already maintained at this connection point. A distribution solution is therefore not considered to be an option.	N/A
5	Non-network solution: Generation	Install or contract sufficient generation support in the ACR area to delay the second transformer. A 13 MW load reduction is required to delay the second transformer by one year. This option will be fully assessed in the project RIT-T process when the reliability cost and availability of generation support will be analysed. However, the prospects for development of significant new generation in the CBD are severely limited.	N/A

Option	Description	Comment	Estimated PV Cost ($m)
6	Non-network solution: Demand side management	Use DSM to reduce load growth in the ACR and defer the installation of the second East Terrace transformer. Demand reduction of 13 MW would be required in the Adelaide CBD area to defer network reinforcement by 12 months. ETSA Utilities advises that there is some potential customer interest, but no firm commitment. This option will be fully assessed in the project RIT-T process. However, the prospects for an economic 13 MW demand reduction under peak load conditions in the CBD at this point are limited.	N/A

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

9.3 Project scope

The proposed works include:

- Installation of a second 275/66 kV 225 MVA transformer.
- Addition of associated circuit breakers, switchgear and metering equipment.
- Addition of Neutral Earthing Reactors to the two transformers at East Terrace and Transformers #2 and #3 at Magill to ensure that phase to earth fault levels are below the three phase levels.

10. Para 275 kV Secondary Systems and Minor Primary Plant Replacement

Project Number: EC.11302

Category: Replacement

Estimated Cost: $49.3m

Required Completion Date: 2015

10.1 Project requirement and timing

Para substation was established in 1967 and is a major component of the electricity supply to the Northern suburbs and is also a key strategic node in the 275 kV main grid transmission network. The electro-mechanical secondary systems at Para were installed as part of the original substation construction and are now 45 years old and in poor condition.

Asset replacement projects are identified in ElectraNet's AMP, which establishes the framework for management of long-term asset risk. A detailed condition assessment and asset replacement risk analysis has been undertaken for Para substation.

The secondary systems, in addition to some remaining items of primary plant, have been assessed as being in poor condition and as having exceeded their effective serviceable life, posing a risk to network reliability. In addition, key components such as electro-mechanical relays now have no manufacturer support, have limited supplies of spare parts and face a very small pool of skilled technicians available to service and repair these assets.

On the basis of this assessment, the secondary systems represent an increasing reliability risk, indicating a need for replacement in the near term.

This project is required to meet the Rules capital expenditure objective to maintain the quality, reliability and security of supply of prescribed transmission services.

10.2 Option analysis

Option	Description	Comment
1	Replace by Asset Class (Brownfield)	This is the lowest cost option.
2	Replace by Asset Class (Greenfield)	This option is not considered to be economically viable because of the size and complexity of the Para Substation facilities, the limited number of primary equipment items needing to be replaced and the substantial costs involved with moving the entire substation and the 275 kV and 132 kV transmission line connections.
3	Refurbishment	This option is not considered to be viable because of the assessed condition, technical obsolescence and the high level of risk associated with catastrophic failure of Para Substation.

Option	Description	Comment
4	Replace on Failure	This option is not considered to be viable because of the assessed condition, technical obsolescence and the high level of risk associated with catastrophic failure of Para Substation.
5	Deferred Replacement	This option is not considered to be viable because of the assessed condition, technical obsolescence and the high level of risk associated with catastrophic failure of Para Substation.
6	Planned Condition Based Replacement	This option is not considered to be viable because of the assessed condition, technical obsolescence and the high level of risk associated with catastrophic failure of Para Substation.

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

10.3 Project scope

The proposed works include:

- Replacement of the secondary system of the Para 275/132/66 kV substation.
- Replacement of a number of associated primary plant and systems, including a 275 kV and 132 kV CVT.
- Replacement of the Telecommunication system and associated works.

11. Keith Substation Replacement and Transformer Upgrade

Project Number: EC.11305 **Category:** Replacement

Estimated Cost: $18.6m **Required Completion Date:** 2019

11.1 Project requirement and timing

Keith substation was established in 1970 and is the sole source of electricity supply for a wide area ranging from Bordertown to Coonalpyn, located in the South East region. It currently comprises two 25 MVA 132/33 kV transformers and is connected to the network via 132 kV circuits from the Tailem Bend and Kincraig substations.

The ETC lists Keith as a Category 4 connection point. This reliability standard requires Keith to have N-1 equivalent transmission line and transformer capacity to meet 100% 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.

It is forecast that Keith will be unable to meet the ETC service standards by 2019-20. Specifically, it is forecast that the contingent loss at peak load of a single transformer at Keith will result in thermal overloading of the remaining unit, ultimately disconnecting the entire load.

Asset replacement projects are identified in ElectraNet's AMP, which establishes the framework for management of long-term asset risk. A detailed condition assessment and asset replacement risk analysis has been undertaken for Keith substation. The majority of assets in the site have been identified as being in poor condition. This indicates that Keith Substation represents an increasing reliability risk, indicating a need for replacement in the short to medium term.

In order to delay the need to upgrade the Keith connection point as long as economically possible, ETSA Utilities is evaluating non-network solutions for the Keith – Bordertown constraints. This option involves the installation of up to 4 MW of embedded generation at or near the Bordertown substation in 2013 and completion of various distribution network upgrades and distribution load transfers. This approach maximises the deferral of the transmission reinforcement (from 2013 to 2019) by use of distribution solutions. ETSA Utilities has incorporated this deferral in the 2012 load forecast for the Keith connection point. No further distribution deferral is expected to be viable.

This project is required to meet the Rules capital expenditure objectives to meet the expected demand for prescribed transmission services over the period, to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

11.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Rebuild Keith as a 132 kV mesh bus substation with two new 60 MVA 132/33 kV transformers	As Keith is a terminal substation, a mesh bus design is proposed for the rebuild. This represents the lowest cost practical option and is the preferred solution.	32.3
2	Rebuild Keith as an ultimate breaker-and-half 132 kV substation with three new 25 MVA 132/33 kV transformers	This is also a technically feasible solution. However, it ultimately provides less N-1 transformer capacity, and at greater cost.	34.8
3	Distribution solution	ETSA Utilities is evaluating non-network solutions for Keith – Bordertown constraints enabling deferral of the need to upgrade the Keith connection point. This option involves the installation of up to 4 MW of embedded generation at or near the Bordertown substation in 2013 and completion of various distribution network upgrades and distribution load transfers. This approach maximises the deferral of the transmission reinforcement by use of distribution solutions (from 2013 to 2019). No further distribution deferral is expected to be viable in this part of the network. In addition, this does not address the need for replacement in the near term based on asset condition.	N/A
4	Non-network solution: Generation	An additional 1 MW generation support is needed at Keith to delay the transformer augmentation by 12 months. The typical cost of a local 1 MW generation support service is estimated at $2.1m. This is an uneconomical means of deferring the network augmentation for any length of time. In addition, this does not address the need for replacement in the near term based on asset condition.	N/A
5	Non-network solution: Demand side management	A 1 MW load reduction is required at Keith to delay the transformer augmentation by 12 months. All available demand side response in the region has is already been factored into the distribution load forecast. In addition, this does not address the need for replacement in the near term based on asset condition.	

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

11.3 Project scope

The proposed scope of works involves:

- Rebuild the Keith substation at an adjacent site as a 132 kV mesh bus substation.
- Replace the existing two 25 MVA 132/33 kV transformers and install 2 x 60 MVA 132/33 kV transformers and associated primary and secondary plant.
- Retire the existing primary and secondary plant.

12. Torrens Island 275/66 kV Transformer Upgrade

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

Estimated Cost: $16.1m **Required Completion Date:** 2015

12.1 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% 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.

It is forecast that Torrens Island will no longer comply with the ETC standards from 2015-16. Specifically, on present load forecasts and assuming low Metro West 66 kV generation availability, the loss of a single 275/66 kV transformer at Kilburn, Le Fevre or Torrens Island will overload the remaining Torrens Island transformers at peak demand by summer 2015-16. Therefore, an increase in the equivalent transformer capacity at the Torrens Island connection point is required by summer 2015-16 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 and maintain the quality, reliability and security of supply of prescribed transmission services.

12.2 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 transformers	The 225 MVA size is currently adopted by ElectraNet as the next standard size for 275/66 kV transformers. This is the lowest cost network option. Hence, it is the preferred solution.	13.6

Option	Description	Comment	Estimated PV Cost ($m)
2	Install a second 225 MVA 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 ETSA Utilities 66 kV network upgrading work, involving significant additional cost.	30.5 + ETSA Utilities 66 kV cost
3	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 an expensive option. It is not possible to complete the required cable work before the end of 2015. Therefore it is not a credible solution.	177.2
4	Distribution solution	Moving load to Le Fevre will overload the ETSA Utilities 66 kV network between Queenstown and Woodville. This option is therefore not viable.	N/A
5	Non-network solution: Generation	This would involve contracting sufficient generation support in the Metro west to defer the need for the transformer upgrade. The availability and cost of this potential 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.	TBD
6	Non-network solution: Demand side management	This option requires sufficient demand side reduction in the western suburbs to defer the transformer limitation. For a deferral of 1 year to 2016, a load reduction in excess of 10 MW is required for 8 hours/day for 5 days, at an indicative cost of $100,000/MWhr. The value of deferring the network option is unlikely to outweigh this cost. This is considered unlikely to be a viable option, but will be fully evaluated during the RIT-T process.	N/A

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

12.3 Project scope

The proposed scope of works involves:

- The replacement of the existing two (2) 275/66 kV 150 MVA units with two (2) 275/66 kV 225 MVA units
- Purchase of an adjacent land parcel to accommodate the extension of the substation

13. Mannum-Adelaide Pump Stations 1-3 and Millbrook Pump Station Substation Replacements

Project Number: EC.11313, 11314, 11315, 10505

Category: Replacement

Estimated Cost: $58.4m

Required Completion Date: 2017

13.1 Project requirement and timing

The three Mannum-Adelaide 132/3.3 kV Pumping Substations (No 1, No 2 and No 3) and the Millbrook Pumping Substation were established between 1959–1969. These sites are located in the Eastern Hills region on the 132 kV sub-transmission network, and are critical in providing the sole electricity supply to pumps operated by SA Water to supply River Murray water to metropolitan reservoirs to support Adelaide' water supply.

These connection (exit) services are prescribed, grandfathered under Rule 11.6.11. The works proposed by ElectraNet are not intended to change the level of service to the customer but merely replace the existing assets with those of modern day equivalent. Following this work the service will remain prescribed unless a change in the level of service is requested by the customer, in which case the connection points will be transferred to a negotiated service.

Based on detailed condition and asset risk assessment, the original plant and equipment in the substations is now well beyond the end of its technical and economic life and requires immediate replacement. Additionally, the switchyards are laid out with electrical clearances that do not meet current standards.

A substantial rebuilding of the substations including the telecommunications, protection and control equipment represents the only viable solution. It is therefore proposed to rebuild the four substations.

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 and to maintain the quality, reliability and security of supply of prescribed transmission services.

13.2 Option analysis

Option	Description	Comment
1	Rebuild existing substations	This is the only option that addresses the asset condition
2	Other options	Non network and distribution alternatives are not viable alternatives as these do not address the condition of the assets or the critical supply failure risk that has been identified.

Option	Description	Comment
3	Do nothing	This option is not considered a viable alternative as it does not address the condition of the assets or the critical supply failure risk that has been identified.

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

13.3 Project scope

The proposed scope of works for each of the sites discussed above include:

- Retiring the existing Mannum-Adelaide 132/3.3 kV Pumping Substations (No 1, No 2 and No 3) and the Millbrook Pumping Substation.
- Establishing four new equivalent replacement 132/3.3 kV pumping substations on adjacent sites to current standards.

14. Morgan-Whyalla Pump Stations 1-4 Replacements

Project Number: EC.11316, 11317, 11318, 11319

Category: Replacement

Estimated Cost: $65.1m

Required Completion Date: 2017

14.1 Project requirement and timing

The four Morgan-Whyalla 132/3.3 kV Pumping Stations (No 1, No 2, No 3 and No 4) were established between 1960 and 1963. These sites are located in the Mid North and Riverland regions on the 132 kV sub-transmission network, and are critical in providing the sole electricity supply to pumps operated by SA Water to supply River Murray water throughout the Mid-North, Yorke Peninsula and Upper Eyre Peninsula.

These connection (exit) services are prescribed, grandfathered under Rule 11.6.11. The works proposed by ElectraNet are not intended to change the level of service to the customer but merely replace the existing assets with those of modern day equivalent. Following this work the service will remain prescribed unless a change in the level of service is requested by the customer, in which case the connection points will be transferred to a negotiated service.

Based on detailed condition and asset risk assessment, the original plant and equipment in the substations is now well beyond the end of its technical and economic life and requires immediate replacement. Additionally, the switchyards are laid out with electrical clearances that do not meet current standards.

A substantial rebuilding of the substations including the telecommunications, protection and control equipment represents the only viable solution. It is therefore proposed to rebuild the four substations.

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 and to maintain the quality, reliability and security of supply of prescribed transmission services.

14.2 Option analysis

Option	Description	Comment
1	Rebuild existing substations	This is the only option that addresses the asset condition
2	Other options	Non network and distribution alternatives are not viable alternatives as these do not address the condition of the assets or the critical supply failure risk that has been identified.
2	Do nothing	This option is not considered a viable alternative as it does not address the condition of the assets nor the critical supply failure risk that has been identified.

14.3 Project scope

The proposed works include:

- Retiring the four existing Morgan-Whyalla 132/3.3 kV Pumping Stations (No 1, No 2, No 3 and No 4).
- Establishing four new replacement 132/3.3 kV pumping station substations on adjacent sites to current standards.

15. Para-Davenport Line Hazard Mitigation

Project Number: EC.11441 | **Category:** Refurbishment

Estimated Cost: $34.0m | **Required Completion Date:** 2016

15.1 Project requirement and timing

The Para – Brinkworth – Davenport 275 kV transmission line was constructed in 1960 to design standards prevailing at that time. This includes the use of load releasing “safety valve cross-arms”. The use of this design has been discontinued due to a safety incident during routine line maintenance early in the history of this circuit and a reinforcement of the cross-arms was subsequently deployed.

A detailed engineering assessment of the cross-arm design has confirmed that these cross-arms represent a safety hazard to maintenance personnel. These structures are inadequate to bear the loads experienced during routine maintenance and inspection access requirements under current policies and standards. This assessment has recommended that the cross-arms be either refurbished or replaced.

Based on detailed condition and asset risk assessment, the porcelain disc insulators on these lines have been assessed as being at practical end of life and require replacement. This has been confirmed through further sample testing undertaken on these lines via two asset maintenance projects completed in 2011. Analysis of the results revealed an insulation failure rate of about 20% within the high bushfire risk zone and concluded that complete re-insulation of these lines is required to mitigate the risk this represents.

The completion date of 2016 ensures that the hazards identified with both the “safety valve cross-arms” and the insulator strings are addressed within the minimum practical timeframe.

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 and maintain the quality, reliability and security of supply of prescribed transmission services.

15.2 Option analysis

Option	Description	Comment
1	Replace all safety valve cross-arms and all insulators on the circuit	This is the most technically viable option. The safety valve cross-arms can only be replaced to eliminate the risk they pose. The risks associated with the insulators are eliminated too and the asset will have a consistent insulation profile and improve reliability and maintenance efficiencies.
2	Replace all safety valve cross-arms and insulators on age	The safety valve cross-arms can only be replaced to eliminate the risk they pose. Records of insulator change are not available in sufficient detail to determine which insulator strings have been replaced. This option is not considered to be technically or economically viable.

Option	Description	Comment
3	Do nothing	This option will expose the network to growing fire, safety and reliability risks. This option is not viable.

15.3 Project scope

The proposed scope of works includes:

- Replace all safety valve cross-arms on the Para-Brinkworth and Brinkworth-Davenport 275 kV lines.
- Replace all porcelain disc insulator assemblies on the Para-Brinkworth and Brinkworth-Davenport 275 kV lines, including insulators, hardware, and line fittings between the conductor to the tower, for each phase at every structure.

16. Neuroodla Substation Replacement

Project Number: EC.11504

Category: Replacement

Estimated Cost: $11.2m

Required Completion Date: 2014

16.1 Project requirement and timing

Neuroodla substation was established in the early 1980s and provides the sole source of electricity supply to the Hawker district and the wider Flinders Ranges area via an extensive 33 kV and 19 kV SWER distribution system. It is located in the Upper North region on the radial 132 kV sub-transmission network. Its construction at the time included the efficient reuse of substation components, most notably a 132/33 kV transformer manufactured in 1952.

Asset replacement projects and their timing are identified in ElectraNet's AMP, which establishes the framework for management of long-term asset risk. A detailed condition assessment and asset replacement risk assessment has been undertaken for Neuroodla substation.

The majority of assets in the site have been identified as being in very poor condition and therefore present a high risk, particularly the 132/33 kV transformer. On the basis of this assessment, Neuroodla Substation represents an increasing reliability risk, indicating a need for replacement in the near term.

The need for early implementation is reinforced by the fact that the entire load supplied from Neuroodla substation would be without supply for several days in the event of a transformer failure. The transformer will be replaced by one of the refurbished ex-Ardrossan West 10 MVA units, representing the prudent reuse of an existing asset.

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 and maintain the quality, reliability and security of supply of prescribed transmission services.

16.2 Option analysis

Option	Description	Comment
1	Rebuild the existing substation on an adjacent site	This is the only option considered technically viable because it avoids lengthy supply outages during construction and it fully addresses the very poor asset condition.
2	Rebuild the existing substation in situ	This option is considered impractical because it would involve the complete disconnection of the entire load for an extended period during the construction.

Option	Description	Comment
3	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 Hawker and the wider Flinders Ranges area in the event of an asset failure.

16.3 Project scope

The proposed scope of works includes:

- Rebuild adjacent to the existing substation to current standards.
- Retire the existing Neuroodla Substation.
- Deploy an existing refurbished 10 MVA transformer from Ardrossan West Substation.

17. Mt Gunson Substation Replacement

Project Number: EC.11505

Category: Replacement

Estimated Cost: $11.4m

Required Completion Date: 2014

17.1 Project requirement and timing

Mount Gunson substation was established in 1970 and provides the sole source of electricity supply for the surrounding districts and is located in the Far North region on the radial 132 kV sub-transmission network. It currently comprises a single 5 MVA 132/33 kV transformer and is connected to the network via a radial 132 kV circuit from Davenport.

Asset replacement projects and their timing are identified in ElectraNet's AMP, which establishes the framework for management of long-term asset risk. A detailed condition and asset risk assessment has been undertaken for Mount Gunson substation.

The majority of assets in the site have been identified as being in very poor condition and therefore present a high risk, particularly the 132/33 kV transformer. On the basis of this assessment, Mount Gunson Substation represents an increasing reliability risk, indicating a need for asset replacement in the near term.

The need for early implementation is reinforced by the fact that the entire load supplied from Mount Gunson substation would be without supply for several days in the event of a transformer failure. The transformer will be replaced by one of the refurbished ex-Ardrossan West 10 MVA units, representing the prudent reuse of an existing asset.

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 and maintain the quality, reliability and security of supply of prescribed transmission services.

17.2 Option analysis

Option	Description	Comment
1	Rebuild the existing substation on an adjacent site	This is the only option considered technically viable because it avoids lengthy supply outages during construction and it fully addresses the very poor asset condition.
2	Rebuild the existing substation in situ	This option is considered impractical because it would involve the complete disconnection of the entire load for an extended period during the construction.
3	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 Mt Gunson and surrounding region in the event of an asset failure.

17.3 Project scope

The proposed scope of works includes:

- Rebuild alongside the existing substation to current standards.
- Retire the existing Mount Gunson Substation.
- Deploy an existing refurbished 10 MVA transformer from Ardrossan West Substation.

18. Magill Telecoms Bearer

Project Number: EC.11543

Category: Augmentation

Estimated Cost: $11.8m

Required Completion Date: 2015

18.1 Project requirement and timing

The Magill substation is presently serviced by telecommunications services operating over radio (via ETSA Utilities' site at Belair) and pilot cable (leased from ETSA) connecting to surrounding substations and the system control centre. Low capacity radio bearers also currently service the Morphett Vale East and Happy Valley substations.

The existing radio bearers providing communication links via Crafers – Cherry Gardens, Belair – Morphett Vale East, Belair – Magill, Belair – Crafers and Crafers – Happy Valley have been identified as requiring replacement due to the assessed condition and risk associated with these assets.

In addition, the capacity of the communication paths servicing Magill, Happy Valley and Morphett Vale East is inadequate to meet forecast service requirements.

Augmentation of the communication paths between Magill and the system control centre, Magill and Para, and Magill, Happy Valley, Morphett Vale East and Cherry Gardens is required to provide sufficient bandwidth for network telecommunications.

This project is required to meet the Rules capital expenditure objective to maintain the quality, reliability and security of supply of prescribed transmission services.

18.2 Option analysis

Optical fibre Ground Wire (OPGW) is the only current bearer technology available that is capable of meeting the forecast bandwidth requirements for network telecommunications in this region. OPGW is considered the most technically viable and economic bearer solution for connecting Para, Magill and Cherry Gardens and also Happy Valley and Morphett Vale East. Buried fibre is considered the most technically viable and economic bearer solution for connecting Magill and the system control centre.

This project completes the fibre loop between the system control centre, City West, Torrens Island, Para, Magill Happy Valley, Morphett Vale East and Cherry Gardens substations, providing a high speed, high bandwidth data path to meet future network telecommunication requirements of the Metro / Inner Eastern Hills Region.

18.3 Project scope

The proposed scope of works includes:

- Install an OPGW telecommunications bearer and associated equipment connecting the Para, Magill and Cherry Gardens, Happy Valley and Morphett Vale East substations.
- Install a buried fibre telecommunications bearer and associated equipment connecting the Magill substation and system control centre.

19. Mt Barker Second 225 MVA 275/66 kV Transformer

Project Number: EC.11625

Category: Connection

Estimated Cost: $11.1m

Required Completion Date: 2016

19.1 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 classifies Mount Barker and Mount Barker South as a grouped Category 4 exit point. This reliability standard requires that Mount Barker and Mount Barker South must have N-1 equivalent transmission line and transformer capacity to meet 100% 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.

Due to the rate of load growth in the Eastern Hills region, it is forecast that the Mount Barker substation will be unable to meet the ETC service standards by 2016-17. Specifically, it is forecast that the contingent loss of the existing single 225 MVA 275/66 kV Mount Barker South transformer at 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 and comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

19.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Install a second 275/66 kV 225 MVA transformer at Mount Barker South	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. This is the preferred option, as it has the lowest PV cost.	10.4
2	Install a third 132/66 kV 60 MVA transformer at Mount Barker and replace the existing transformers	This is not considered as a viable, cost effective solution as it requires three new transformers and a complete site rebuild at Mount Barker substation due to the age and condition of the existing assets.	21.6

Option	Description	Comment	Estimated PV Cost ($m)
3	Distribution solution	Load transfer options were investigated with ETSA Utilities but proved technically unviable.	N/A
4	Non-network solution: Generation	A 4 MW load reduction in 2016/2017 is required to delay network augmentation by 12 months The cost of a typical 2 MW generation support service is estimated at $3.5M. 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 4 MW would be required in the Mount Barker region to defer network reinforcement by 12 months. Advice from ETSA Utilities indicates that there is insufficient demand reduction available to meet this requirement. 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.

19.3 Project scope

The proposed scope of works involves:

- Installing a second 275/66 kV 225 MVA transformer at Mount Barker South Substation.
- Retiring the Mount Barker 132 kV substation.

20. Online Asset Condition Monitoring Equipment Replacement

Project Number: EC.11733

Category: Replacement

Estimated Cost: $11.8m

Required Completion Date: 2017

20.1 Project requirement and timing

ElectraNet's asset management policy is built around asset condition monitoring, with a large portion of this analysis currently supported by online intelligent monitoring devices. The online condition monitoring devices predominantly comprise microprocessors, sensors and communications devices.

Specialist electronic items usually have a defined usable life (10+ years) due to reliability issues with the electronics and the fact that rapid technology advancements generally cause older electronic devices to become obsolete and in most cases incompatible with newer technologies, and newer operating systems.

The majority of ElectraNet's Primary Plant online condition monitoring equipment is now at the end of its usable life and will require complete or partial replacement or refurbishment.

The replacement strategy is generally a like for like replacement of all devices (to the latest available version) with exception of the Power System Performance Monitor (PSPM) where a new brand is required as a replacement due to the obsolescence of the existing technology.

Replacement of this obsolete equipment will support the continuation of network monitoring to provide data for fault investigation, power quality monitoring, condition assessment and reliability measures as required by the Rules, ElectraNet’s fault investigation processes and transmission system operation.

This project is required to address the Rules capital expenditure objective to maintain the quality, reliability and security of supply of prescribed transmission services and maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

20.2 Option analysis

Option	Description	Comments
1	Replacement of obsolete items within the defined period of 5 years	This option is the only technically viable option because it will replace all the obsolete items within a period that can be resourced and has a low risk to security and reliability requirements.
2	Replace items on an as need basis (i.e. after failure)	This option is not considered a viable option as it accepts the loss of asset condition and monitoring data that could be critical to any failure investigation.
3	Do nothing	This option is not considered viable because it is not deemed prudent or sustainable to continue with the existing obsolete equipment and would not satisfy the obligations under the NER.

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

20.3 Project scope

The scope of works will require the following obsolete equipment to be replaced / upgraded:

- GE Hydran Oil and Gas Monitors;
- LTC Map Transformer Monitoring;
- Ametek (Rochestor) Power System Performance Monitor;
- Hathaway Travelling Wave Fault Locator;
- Hathaway Distribution System Fault Locator;
- Insulator Pollution Monitors.

21. Dalrymple Second 132/33 kV Transformer and Mesh 132 kV Bus

Project Number: EC.11826

Category: Connection

Estimated Cost: $30.8m

Required Completion Date: 2016

21.1 Project requirement and timing

Dalrymple substation was established in 1987 provides the sole source of electricity supply for the southern Yorke Peninsula. It currently comprises a single 25 MVA 132/33 kV transformer and is connected to the network via a radial 132 kV circuit from Ardrossan West.

The ETC assigns Dalrymple connection point to a Category 1 reliability level until 1 December 2016. To date this reliability standard has only obligated ElectraNet to provide system normal transmission line and transformer capacity with no requirement for any redundancy.

From 1 December 2016, the ETC reassigns the Dalrymple connection point to a Category 2 reliability level. This standard requires ElectraNet to have in place N equivalent transmission line and N-1 equivalent transformer capacity to meet 100% of the 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 capacity within 2 days of the interruption and N equivalent transformer capacity within 8 days of the interruption.

In addition, ElectraNet's Transmission Connection Agreement under the Rules with ETSA Utilities requires that voltage levels at prescribed connection points must be kept above 90% of the nominal voltage level following any single contingency in the network supplying that connection point. Network analysis shows that from 2016-17, for an outage of the Hummocks to Bungama 132 kV transmission line, voltage levels at the Ardrossan West, Dalrymple, and Kadina East connection points will drop below 90% of the nominal voltage.

This project is required to meet the Rules capital expenditure objective to meet the expected demand for prescribed transmission services over the period and comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

21.2 Option analysis

Option	Description	Comment	Estimated PV Cost ($m)
1	Rebuild the Dalrymple substation at a nearby site to include two 25 MVA 132/33 kV transformers, and install 1 x 8 Mvar 132 kV capacitor at the new site.	The capacitor will address the forecast low voltage levels, while the transformers will provide the additional capacity required. This is the least cost option that addresses the identified constraint and is the preferred option.	30.8

Option	Description	Comment	Estimated PV Cost ($m)
2	Rebuild Dalrymple substation at a nearby site to include two 25 MVA 132/33 kV transformers, and perform major augmentation of supply to the Yorke Peninsula system (establish 275/132 kV injection at Hummocks substation, supplied by turning the 275 kV Para to Bungama line in and out to Hummocks)	Much higher cost solution and insufficient time to implement. While technically feasible, this option is not economic.	185.1
3	Distribution solution	There is no available distribution load transfer that can resolve this constraint owing to the radial supply configuration in this region. Also, power factor correction cannot assist in meeting the limitation, hence this is not a viable option.	N/A
4	Non-network solution: Generation	Generation is not capable of meeting the reliability standard requirement, hence this is not a viable option	N/A
5	Non-network solution: Demand side management	Demand side management cannot address the increased reliability requirement required by the ETC, hence this is not a viable option	N/A

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

21.3 Project scope

The proposed scope of works involves:

- Rebuild the Dalrymple Substation at a nearby site.
- Install a second 25 MVA 132/33 kV transformer to meet the ETC code requirements.
- Install 1 x 8 Mvar PoW switched capacitor bank.
- Installation of associated switchgear including one 132 kV circuit breaker and two 33 kV circuit breakers on the low side of the transformers.
- Decommissioning, removal of assets and remediating of the existing site.

22. NGM CT, VT and Meter Replacement

Project Number: EC.11847 **Category:** Replacement

Estimated Cost: $16.5m **Required Completion Date:** 2017

22.1 Project requirement and timing

During the mid-1990s ElectraNet installed the majority of its 'National Grid' metering installations prior to joining the National Electricity Market (NEM). The purpose of these installations was to meter connection points where energy enters and leaves the regulated South Australian Transmission Network.

The National Electricity Code (NEC) that applied at that time allowed existing (non-code compliant) instrument transformers to be used, provided that metering was in service prior to joining the market. However, the NEC stated that this was only allowed as a market start concession, and that under these transition rules the non-compliant instrument transformers had to be replaced after market start (or from time of joining the NEM).

The purpose of this project is therefore to replace a number of non-compliant current transformers (CTs) and voltage transformers (VTs) that are presently used for National Grid Metering (or revenue metering) purposes that remain in the ElectraNet system. The project also involves the replacement of all remaining EDMI system 2000 Mk 2 revenue meters.

Non-compliant instrument transformers are defined as those that do not have the nameplate accuracy or insufficient metering cores, as defined by the current National Electricity Rules (NER).

The EDMI System 2000 Mk 2 meters are all over 15 years old, and no longer have manufacturer support. These meters are also starting to exhibit higher than acceptable failure rates. These meters have exceeded their design service life and need to be replaced from a reliability and risk perspective.

To improve remote meter reading availability, the opportunity will be taken to provide a second phone service into all NGM sites, which are using Mk 2 and Mk 3 meters. This will improve the remote access practices at these sites to match the current design standards.

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.

22.2 Option analysis

Option	Description	Comment
1	Replace the listed instrument transformers and meters, and install a second phone service.	This is the only option considered technically viable because it addresses critical condition of the meters and the requirements of the Rules Schedule 7.2.
2	Do nothing	This option is not considered a viable alternative because it does not address the critical condition of the meters or the requirements of the Rules.

22.3 Project scope

The proposed scope of this project involves the following works at the relevant substations, as required on a case by case basis:

- Instrument transformer change-out only.
- Instrument transformer and meter change-out.
- Meter change-out and provision of second phone service.
- Provision of a second phone service to site for NGM remote access.

23. Unit Asset Replacement 2013–18

Project Number: EC.11890

Category: Replacement

Estimated Cost: $35.3m

Required Completion Date: 2017

23.1 Project requirement and timing

Unit asset replacements involve individually identified in situ replacements of substation assets, including circuit breakers, voltage transformers, current transformers and protection relay sets.

These are predominately assets that are unreliable or at the end of their technical and/or economic lives based on condition and risk assessment. The scope of this project includes only those assets that will not be replaced as part of an augmentation project or substation rebuild project scheduled for the forthcoming regulatory period. 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.

The nominated assets are located at a range of locations on the 66 kV, 132 kV and 275 kV transmission network.

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.

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.

23.2 Option analysis

Option	Description	Comment
1	Replace high risk aged assets in-situ	This option is the optimal technical and economic solution. It allows a planned approach to the replacement of the assets prior to failure on a risk basis.
2	Replace on condition	This option produces a similar result to the do nothing option considered below, and does not address the increased corrective maintenance costs or the impact on the reliability risk to the network that these assets pose. This option is not considered to be viable.

Option	Description	Comment
3	Do nothing	This option will expose the network 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. Under this option, 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.

23.3 Project scope

The proposed works include:

- Replace the identified circuit breakers, capacitive voltage transformers, voltage transformers and current transformers.
- Replace the identified protection relays.