Attachment G.1a

Attachment_SAPN_Kangaroo Island submarine cable-Additional information

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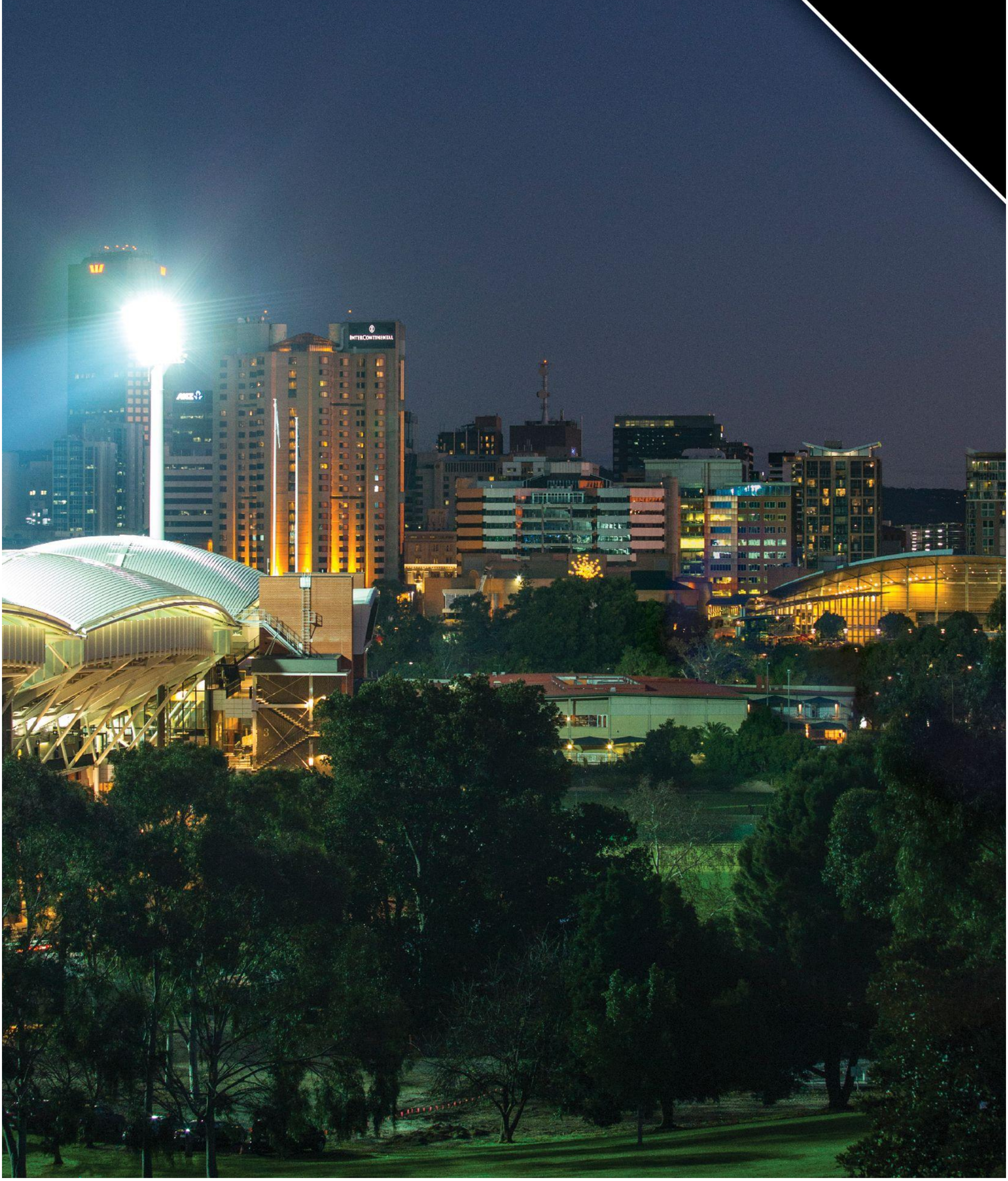

Kangaroo Island submarine cable – Additional information

Contents

1. Response to the AER's Preliminary Determination

SA Power Networks agrees with the AER's preliminary decision to allow funding to install a second undersea cable to Kangaroo Island (**KI**) in its Preliminary Determination. The proposal to install the second KI submarine cable has received support from the South Australian Government to 'avoid unnecessary impacts for the community and the Island's reputation as a tourist destination' and ensures a secure electricity supply to KI in the long term.

SA Power Networks agrees with the AER's consideration that the cable replacement "may … be a prudent and efficient course of action if it can be shown that the likely costs to consumers are minimised by the early installation of the cable."[1] A modified cost benefit analysis based on EMCa's model further demonstrates the installation of a second cable in 2017/18 delivers the lowest cost to our customers compared to running the existing cable to failure or implementing a non-network hybrid solution. The net present value (**NPV**) model confirms there is no economic benefit gained by deferring the second undersea cable to KI.

We refer to the AER's "PELIMINARY DECISION SA Power Networks determination - Attachment 6 - Capital expenditure - April 2015", published on 30th April 2015. SA Power Networks provides the following information in response to those matters highlighted in its Preliminary Determination.

2. AER/EMCa's review

SA Power Networks agrees with EMCa's final assessment supporting the replacement of the KI cable prior to the end of its economic life. However, SA Power Networks would like to clarify an incorrect assumption concerning voltage support made by EMCa. Taking the correct assumption into consideration further supports the cable replacement assessment.

EMCa has incorrectly assumed voltage support on the 33kV sub-transmission line between Penneshaw and American River is required under all scenarios and therefore excluded this expenditure from its analysis. The copper conductor of the existing submarine cable has a diameter of 50mm. The proposed cable will have larger copper conductor (> 150mm) to accommodate the forecast new cable rating. A conductor with a greater diameter incurs less voltage drop than a conductor with a smaller diameter of the same length. Therefore in the short to medium term the voltage drop through the new KI cable will be reduced thus deferring the need to provide additional voltage support via a new 33kV voltage regulator station until 2045. This assumes the existing cable fails in the same year the new submarine cable is installed. However, if the old cable remains in service it will continue to provide additional capacitance to the network, further reducing the losses in the network and deferring the requirement to install voltage support to beyond 2045. When using the Regulatory Investment Test – Distribution (**RIT-D**) model, voltage support expenditure is included in the analysis, however EMCa's model only examines deferral scenarios until 2028/29. Option 1, run the cable to failure, requires voltage support in 2030 based on the existing growth rate. EMCa's NPV results do not take this into consideration.

SA Power Networks has noted EMCa's observation and assessment of our RIT-D model 3. The RIT-D model will be reviewed and modified based on EMCa's recommendation prior to engaging potential market solutions in accordance with the NER and the AER Guidelines.

Based on EMCa's NPV model, SA Power Networks has included a non-network option to determine if a renewable option is more efficient than the installation of a second submarine cable. The NPV

[1] AER's Preliminary Decision SA Power Networks determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure, April 2015, p65.

analysis shows that the installation of second cable in 2017/18 still delivers the lowest cost to our customers compared to implementing a non-network hybrid solution. The consideration and evaluation of non-network options is described below.

3. Consideration of non-network options

SA Power Networks has noted the concerns of some stakeholders that SA Power Networks has not considered alternative options to ensure the security of supply for KI.

For example, Business SA believes "renewable options have not been adequately explored. It should be possible to offset 40% or more of the diesel usage cost effectively using a mix of wind and solar. We have seen working examples of renewables used in hybrid wind/diesel and solar/diesel remote systems with renewables coming in at a cost of around $3/W".

However, using wind energy deployments in isolated, regional grids in Western Australia (e.g. Esperance Nine Mile Beach, Hopetoun and Denham) as a basis for estimating the cost of a renewable supply option as recommended by Business SA is not valid. Wind turbine generation is variable, depending on the wind. When the wind is not blowing, wind turbines do not generate power and the short-fall has to be made up from other generation sources. For example, the Esperance Ten Mile Lagoon and Nine Mile Beach Wind Farm can supply up to 20% of Esperance's electricity (if running continuously) but most electricity is still generated by a gas turbine facility.

The suggested nominal 7MW wind farm ($21M based on $3/W fully installed) by Business SA will not be able to support the base load of KI when the wind is not blowing. Similar to wind farms at Esperance, Hopetoun Power System is a wind-diesel system ($8.1M 2008 $) which has a capacity of 1.2MW of wind power and 2.24MW of diesel power. The wind farm is only expected to produce up to 40% of Hopetoun's annual electricity demand. Hopetoun is still heavily reliant on its expensive diesel fuel to meet the majority of its demand.

Overall, the application of large renewable generation such as wind farms on KI is expensive compared to some other locations. The existing KI network is unable to support large connections in its current configuration. A major upgrade of the 33kV network and substation with expensive dynamic voltage control equipment would be required to facilitate the connection of a large renewable generator. Excluding the capital cost of such solutions, even if renewable sources effectively offset 40 - 60% of the annual diesel usage based on a 4MW KI average load, the generators will still consume an average of 12,400 - 18,600 litres of fuel per day. Assuming $1.4371 per litre, this equates to an annual fuel cost of approximately $4.5 - $9.8M. High levels of diesel generation would still play a major role to provide base load on KI, and obviously this is not economically attractive.

In addition, it is also important to note that wind turbines have high maintenance requirements and are typically designed for a 20 year life. Additional capital expenditure for refurbishment / replacement of the wind turbines is required after 20 years, compared to a 30 year design life of a submarine cable with minimal operational costs. When considering operational and maintenance costs of wind farms, other renewable sources and their shorter asset lives, the NPV analysis would be considerably worse for the renewable solution.

The use of King Island as a basis for estimating the cost of a renewable supply option is considered unreasonable by Business SA and Total Environment Centre (**TEC**) with claims that King Island does not represent best practice in costs for an operational system. However, since the successful application of hybrid renewable generation on King Island, Flinders Island and Coober Pedy have been adopting renewable energy enabling technologies developed by Hydro Tasmania. Even if King island is regarded unsuitable for benchmarking purposes, the Flinders Island and Coober Pedy Hybrid projects still support the fact that a renewable generation solution on KI as an alternative to the submarine cable is not economically viable, as detailed below.

Flinders Island has an installed generation capacity of 2.8MW with a peak load demand of approximately 1.2MW (15% of KI's current peak load). The Flinders Island Renewable Energy Integration Project, which is due for completion in November 2016, will see an investment of $12.88M. $5.5M of this amount is funded from the Australian Renewable Energy Agency (**ARENA**) (43% of total project cost). Based on the Flinders Island cost ratio, the KI project could potentially cost approximately $84M (excluding high annual operating expenditure) to implement a similar integrated renewable solution.

Similarly, Energy Developments Limited (**EDL**) operates the Coober Pedy Power Station which has an installed generation capacity of 3.9MW and a peak load of approximately 3MW (50% of KI's current peak load). The Coober Pedy Renewable Hybrid Project will receive $18.5M from ARENA for its 2015 project to install up to 2MW of solar PV and 3MW of combined wind generation and battery storage. It is worth noting that ARENA has supported, on average, 40% of the total cost of hybrid/enabling technologies projects valued above $2M. This is consistent with the percentage of funds provided to the Flinders Island Project (43%). By applying a similar 40% - 43% of project funding, the Coober Pedy Project can be estimated to cost approximately $43M - $46M excluding operating expenditure and fuel cost. Therefore, the hypothetical hybrid KI project could potentially cost $86 - $92M (excluding annual operating expenditure) to implement a similar integrated renewable solution to that of Coober Pedy.

For many remote locations with no viable network solutions and which are heavily reliant on diesel fuel to supply electricity, these hybrid solutions make good economic sense and have been successful in increasing renewable energy use, reducing reliance on diesel fuel. However, diesel fuel is still crucial to generate the required electricity for these remote locations. The Flinders Island and Coober Pedy hybrid power stations are expected to displace at least 40% of their current annual consumed diesel fuel by implementing a combination of wind and solar generation, battery storage system, dynamic resistive frequency control, Diesel-Uninterruptable Power Supply, modularised LV switchgear and integrated complex system.

Based on the cost analysis model created by EMCa and accepted by the AER, SA Power Networks has included a preliminary NPV analysis to include a non-network option (Hybrid Power Station) to determine if a renewable option might be more efficient than the installation of the second submarine cable. The NPV analysis shows that by taking into account 40 -60% of annual fuel cost and the 7MW Wind farm (as recommended by Business SA), the net present cost of this option is more than two or three times that of the cable solution. This excludes consideration of other significant costs such as a 33kV network upgrade, operating and maintenance of the wind farm/power station and integration of other renewable and smart grid systems. Adding these costs into the analysis, the net present cost is many times more than the cable replacement solution. The value of energy generated by renewable sources has minimal impact on the NPV modelling. Sensitivity analysis shows the renewable solution (wind farm) must be capable of displacing more than 85% of the annual diesel fuel used on the island to be comparable to the cable replacement option. Such a reduction is not feasible at this time because the capacity factor of wind turbines, which is the ratio between average power produced and full capacity, is only around 30 – 40%.

From the data available, it appears that renewable sources are only economical in isolated locations with no access to a traditional network supply, and where expensive diesel energy can be displaced. For the KI system that has an existing network supply, renewable sources are unable to compete with grid solutions, that is, the construction of a new hybrid power station, the upgrade of the existing 33kV network and substation on KI along with high annual operating expenditure and fuel cost is less economical than the installation of the second submarine cable. A formal RIT-D process will be undertaken prior to SA Power Networks committing to the installation of a second undersea cable. This process will allow third party proponents to submit non-network solutions at that time. All proposed solutions will then undergo further consideration and analysis.

4. Consideration of alternative network options

4.1 Pre-paying (jump the queue payment)

The AER has requested that SA Power Networks explore the option of paying a deposit with a cable supplier to ensure a shorter delivery time when the order is placed (i.e. a jump the queue payment). SA Power Networks has contacted six cable suppliers regarding this option, and five out of six cable suppliers advised a jump the queue option is unavailable.

Such an option to jump the production queue is not recommended by suppliers as this may ultimately cause delays to the production of other customer orders. It is also advised that once a submarine cable is placed into the manufacturing line, it is difficult to stop the production and place a new order in. A “first come, first served principle” is applied by cable manufacturers in most cable production plants. An option to prepay only applies if the cable date production window can be confirmed or fixed.

For the single cable supplier that advised it may be possible to accept this proposal, the supplier still has to consider the opportunity cost related to other projects, the size of the order and the strategic importance before making any commitment. The KI cable project is considered to be a small to medium size project when compared to other submarine cable orders in the current market and therefore is limited in terms of its bargaining and negotiating influence.

4.2 Alternative Network Options

The AER requested that SA Power Networks seek information on the technical feasibility of pre-purchasing and storing the cable. Most cable suppliers that were consulted have confirmed that the full length of the cable can be coiled. However, they have advised that it is costly and inefficient to load the cable onto a ship, then off the ship for storage and then back onto a cable laying ship. Cable suppliers recommend manufactured submarine cables to be loaded directly onto a cable laying ship or specially converted barge for installation.

Another cable supplier confirmed that it would be a very costly exercise to transport the cable and store a single long length of submarine cable. The cable must be transported on x 32, 500 metre drums. This would require many straight joints during the actual installation. This method is not recommended by the supplier or SA Power Networks, as cable joints are common points for cable failure.

As the AER has described, “the cost involved in the transport, storage and retrieval as set out by SA Power Networks would exceed the benefits of deferring installation until the existing cable fails”. In addition, there would be significant risk of damaging the cable during these extra handling operations which require specialist expertise. Contractors try to avoid increasing the transhipment operations to minimise the risk of unexpected damage. The insurance and warranty of the equipment may expire depending on how long they are stored. This further complicates this option.

Out of the six suppliers consulted, only one advised that it may be feasible to store the cable in their cable factory. However, this is dependent on the final cable design, factory capabilities and length of storage.

5. Stakeholders submissions

SA Power Networks has reviewed comments made in stakeholder submissions and offers the following information.

5.1 Business SA

Business SA recognises the importance of KI to the SA economy where prolonged outages or restrictions in supply would have a highly detrimental impact on businesses and the community. Business SA's concern is that the solution proposed by SA Power Networks is expensive and does not clearly state the level of security required by KI. Business SA argued that there is little evidence the existing cable has significantly deteriorated and is likely to fail. It is currently 22 years old, with an expected life of 30 years.

The AER noted the previous cable suffered its first fault at 22 years. Fortunately, the first failure occurred in the onshore section and could be repaired, however not without significant disruption to the customers on KI. The second cable failure occurred mid ocean and an inspection of the cable identified that the condition of the armour was at a state of deterioration such that any attempt to lift the cable to facilitate repairs would likely transfer additional stress to the cores and cause future failure. It was confirmed the cable was no longer serviceable and therefore the cable was abandoned as it was not financially viable or technically feasible to repair. SA Power Networks supports the AER's view that installing an additional cable is an efficient and prudent course of action, as proven in the NPV analysis undertaken by SA Power Networks and the AER. Cost benefit analyses support and justify the replacement of the cable in the 2015-20 Regulatory Control Period (**RCP**). Implementing a non-network solution or running the cable to failure and then installing the new submarine cable are lower NPV options.

The CIGRE cable data cited by Business SA notes that "85% of failures in undersea cables is caused by external damage, not age". Business SA commented that "even if the existing cable is at risk of imminent failure, simply replacing it with another still leaves the island connected by a single cable, with 85% of the risk of failure remaining (due to damage, not age)". While internationally undersea cables are often damaged by external factors, historically this has not been an issue for the KI cables to date. However it is still a potential risk. The new submarine cable will be laid away from the existing cable reducing the probability of both cables being damaged by the same event.

Business SA incorrectly believes that the proposed solution leaves KI with no better security than it currently has, but at $47M is a very expensive solution. The security of supply to KI is considerably improved by the installation of the second cable until the first cable approaches its 30 year nominal life.

Business SA believes the option of local generation has not been adequately explored and considered the existing diesel generators on the island as not fit for purpose. SA Power Networks advises the standby generators are designed for standby purposes only. It is uneconomical to invest in building a high cost power station for a permanent backup solution. The capital cost of a power station and its operating cost are excessive largely due to fuel and urea costs ($16M a year), operating and maintenance teams, hire and mobilisation of additional generators, provision of extra fuel tanks and handling, remote location expenses, engine maintenance, spares and repairs. Commercial customers on KI would have adopted diesel generation if diesel was thought to be more economically viable. One particular customer on a Demand Management program on KI is unhappy when occasionally asked run their diesel generators.

Business SA enquired about the discrepancy costs in the previous regulatory submission at $80M. For clarification, the scope of work that SA Power Networks is proposing as part of the 2015 -20 RCP has been reduced from the 2010 submission. The previous 2010 solution included the installation of a new sub-transmission powerline on KI to facilitate major demand growth. With lower demand growth now forecast, this is now not recommended for many years and is not part of our 20 year plan. Therefore, the current submission is only for the installation of a new submarine cable.

Business SA claims that “the photographic evidence of the existing cable having substantial damage is inconclusive”. Visual inspection of the cable in 2012 revealed the outer serving (covering) is damaged and corrosion was evident, which is an indicator of cable deterioration.

Business SA claims “much of the cable is ….. buried under the sea floor, which CIGRE notes provides protection from damage”. Whilst SA Power Networks agrees sand provides some degree of protection for the cable, the sand decreases the cable rating and makes it more difficult to find and extract in the event the cable requires repair. SA Power Networks concurs that cables buried under the sea floor have advantages and disadvantages and as such a cable’s performance should be reviewed based on its location. There is no designated shipping channel within Backstairs Passage. Most of the cable route lays within a designated Habitat Protection Zone (HPZ-6) as designated in the Encounter Marine Park Management Plan. As such, the risk of anchor impacts on cables laid on the sea bed within Backstairs Passage is low.

5.2 Energy Consumers Coalition of SA

The Energy Consumers Coalition of SA (**ECCSA**) notes that SA Power Networks is proposing to install the cable ahead of the end of the existing cable’s design life. However AER considers that “this may be a prudent and efficient course of action if it can be shown that the likely costs to consumers are minimised by the early installation of the cable”.

Further analysis by SA Power Networks (provided to the AER) included a normalised probability of failure of the cable with a cumulative 50% probability of failure when the existing cable reaches 30 years of age. Under all modelled scenarios, the net present cost to consumers is minimised by the installation of the cable in the 2015 -20 RCP. EMCa were engaged by the AER to undertake a peer review of SA Power Networks’ analysis and evidence that was submitted to the AER. EMCa agrees the application of a probability of failure into the NPV analysis is reasonable. EMCa concluded the analysis and evidence supports the inclusion of the submarine cable capital expenditure in the 2015-20 RCP.

SA Power Networks disagrees with ECCSA’s comment regarding the effective increase in reliability to N-2 level security on KI with the installation of the new cable. The Kingscote power station was designed for standby capacity for short durations of operation for either network support or interruptions and is insufficient to supply KI during peak load periods. While the old cable remains in service, it will be used to assist the power station in managing total load if the new cable fails. As described in the Original Proposal Attachment 30.38: Asset Management Plan 2.1.03 Kangaroo Island - Network Security second undersea cable, Section 4.6, any availability of the old submarine cable beyond 2018 will allow deferral of the power station capacity upgrade and therefore provide cost advantages to our customers. However, once the old cable fails the need to upgrade the power station will be necessary to keep pace with the increasing KI demand.

ECCSA noted that a number of facilities on KI already have diesel generators as back up. As described in the Original Proposal Attachment 30.38: Asset Management Plan 2.1.03 Kangaroo Island - Network Security second undersea cable, Appendix 4, self-generation was limited to emergency backup, typically works for short durations and cannot supply electricity 24/7 during peak demand periods. These generators will incur more frequent breakdowns and malfunctions if operated for longer than the prescribed number of continuous operation hours. A more efficient and secure solution is required should the existing submarine cable experience a failure.

5.3 Total Environment Centre

Total Environment Centre (**TEC**) accepts the need for a reliable and secure supply to KI, however it questions the solution of installing the new cable as being the best option.

To be a viable alternative to a second KI cable, any non-network solution (e.g. Hybrid Power Station) would need to be able to run islanded for an extended period of time, with a similar reliability level to the cable (including the ability to manage varying demand and voltages) and provide a lower overall cost to customers over the evaluation period.

SA Power Networks has not directly engaged potential market solutions, although a formal RIT-D assessment will be undertaken in line with the NER and AER Guidelines prior to project commencement. Serious alternative renewable options will be considered through formal consultation required under the NER. As such, community renewable energy projects referred to by TEC can be submitted as options through the RIT-D process. If the RIT-D consultation process discovers a more efficient non-network solution that meets the required technical standards compared to the installation of the KI submarine cable, SA Power Networks will then proceed with the non-network solution.

A preliminary option analysis of potential non-network solutions was considered as part of the revised reset submission. The non-network solution (combination of wind and diesel power station) was not a viable economic alternative to replacing the submarine cable.