Towards 100% Renewable Energy for Kangaroo Island

PREPARED FOR:

ARENA, RENEWABLES SA and KANGAROO ISLAND COUNCIL

BY:

UTS: INSTITUTE FOR SUSTANABLE FUTURES

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SUMMARY

A powerful choice for Kangaroo Island

Kangaroo Island's electricity is currently supplied through a 15 km submarine cable from mainland South Australia. As this cable is approaching the end of its design life, SA Power Networks (SAPN), the business responsible for the local electricity distribution network, is investigating options for future electricity supply for the island. The preferred network option is a replacement submarine cable at an estimated capital cost of $45 million (+10%, -50%). As required by the National Electricity Rules, SAPN is undertaking a Regulatory Investment Test – Distribution (RIT-D), including seeking proposals for non-network alternatives to a new cable.[1]

This study, ***Towards 100% Renewable Energy for Kangaroo Island***, complements SAPN's investigation by assessing options for reliable local power supply that would meet Kangaroo Island's electricity needs from resources on the island, while delivering power reliability that is equivalent to or better than would be provided by the new cable option. This local power supply would be largely based on renewable energy sources including wind, solar and potentially biomass, supported by batteries, demand management and back-up diesel generation. This study also considers how local supply options could allow Kangaroo Island to transition towards 100% renewable power.

This study finds that the overall direct and indirect costs of local electricity supply would be comparable to the cost of the new cable option. The choice of power supply is therefore likely to depend on other factors, such as the preferences of the local community, how costs, benefits and risks are shared, and the level of engagement and support from other key stakeholders including SAPN, governments and regulators.

Local electricity supply a cost-competitive option

This study considers ten possible scenarios, based on publicly available data, for meeting the electricity needs of Kangaroo Island over a 25-year time horizon. Based on current technology and costs for renewable energy, and for other generation and network services, a reliable, local "**Wind-Solar-Diesel Hybrid"** Scenario is estimated to be broadly comparable in cost to the **New Cable** Scenario. The Wind-Solar-Diesel scenario would likely include doubling the existing 8 MW diesel generation capacity, four to eight wind turbines, five hectares of solar farm and additional solar panels on about 800 rooftops.

The direct cost for the New Cable Scenario is estimated at **$77 million** (including the capital costs for the new cable and the cost of mainland grid-supplied electricity consumed on Kangaroo Island). This is *11% less than* the **$87 million** for the Wind-Solar-Diesel Hybrid Scenario. However, if indirect costs including network charges are included, costs for the New Cable Scenario rise to **$169 million,** *6% more than* the **$159 million** for local supply. The estimated cost difference between the scenarios is thus relatively small, and well within the range of uncertainty.

The Wind-Solar-Diesel Hybrid Scenario is estimated to provide about 86% renewable power supply (wind and solar) to the island, with the remaining 14% provided by new diesel generators. This solution could very likely provide reliable supply on Kangaroo Island by December 2018 and it could be fully established within four years. Such Wind-Solar-Diesel hybrid solutions have been demonstrated in numerous places over recent years, including on King Island, Tasmania.

[1] SAPN 2016 *Non-Network Options Report (NNOR): Kangaroo Island Submarine Cable*

Towards 100% renewable local energy supply

The Wind-Solar-Diesel Hybrid Scenario also provides a strong foundation to transition to a 100% renewable power supply. This study examines several scenarios for providing 100% local renewable power for Kangaroo Island. Of these scenarios, one was considered to provide a credible balance of cost, reliability, risk and community acceptance. This **Balanced 100% Renewables** Scenario would use Kangaroo Island's unused timber plantations to fuel biomass electricity generation to complement the wind and solar resources in the Wind-Solar-Diesel Hybrid Scenario.

The biomass generation would largely displace imported diesel fuel generation. Plantation timber is a much less expensive fuel than diesel, but the capital cost of the biomass plant would be considerable (about $25 million), so the Balanced 100% Renewables Scenario is estimated to cost about 15% more than the Wind-Solar-Diesel Hybrid Scenario, at **$100 million** (direct costs) or 7% more at **$166 million** (including indirect costs).

For this scenario, a small amount of diesel-generated power will still be required on rare occasions when power demand is relatively high, wind and solar output are both low, biomass generation is unavailable or fully utilised, and battery and demand management capacity are exhausted. It is estimated that such diesel back-up generation would likely provide less than 1% of total electricity supply. If this small volume of diesel generation was fuelled by renewable biodiesel[2] instead of conventional mineral diesel fuel, then Kangaroo Island could be supplied with 100% renewable power. Such a 100% renewable system could be established within five years.

Table 1: Estimated costs of new cable and local power supplies scenarios

Scenario	New Cable	Wind-Solar-Diesel Hybrid	Balanced 100% Renewables
Direct costs (NPV)	**$77 million**	**$87 million**	**$100 million**
Capital expenditure (amortised)	$34 million[3]	$60 million	$87 million
Operating expenditure	$43 million	$42 million	$29 million
(less Renewable Energy Certificates)	0	(-$15 million)	(-$16 million)
Range of direct costs	$57-96 million	$70-102 million	$69-129 million
Direct & indirect costs	**$169 million**	**$159 million**	**$166 million**
Range of direct & indirect costs	$141-198 million	$119-184 million	$113-204 million

[2] As has been demonstrated on King Island. http://www.kingislandrenewableenergy.com.au/project-information/biodiesel-trial

[3] The cable capital cost is $36 million, the centre of the range of uncertainty in the NNOR, amortised over a 35-year anticipated lifetime, and (as with all costs) is expressed as a net present cost over 25 years.

Supply scenario costs

The estimated costs and the range of uncertainty of New Cable, Wind-Solar-Diesel Hybrid and Balanced 100% Renewables Scenarios are shown in Table 1. These estimates are based on conservative assumptions about the current and future costs of renewable energy technologies and they include the costs of covering the risk that the existing undersea cable may fail during the four years required to implement the Wind-Solar-Diesel Hybrid Scenario.[4]

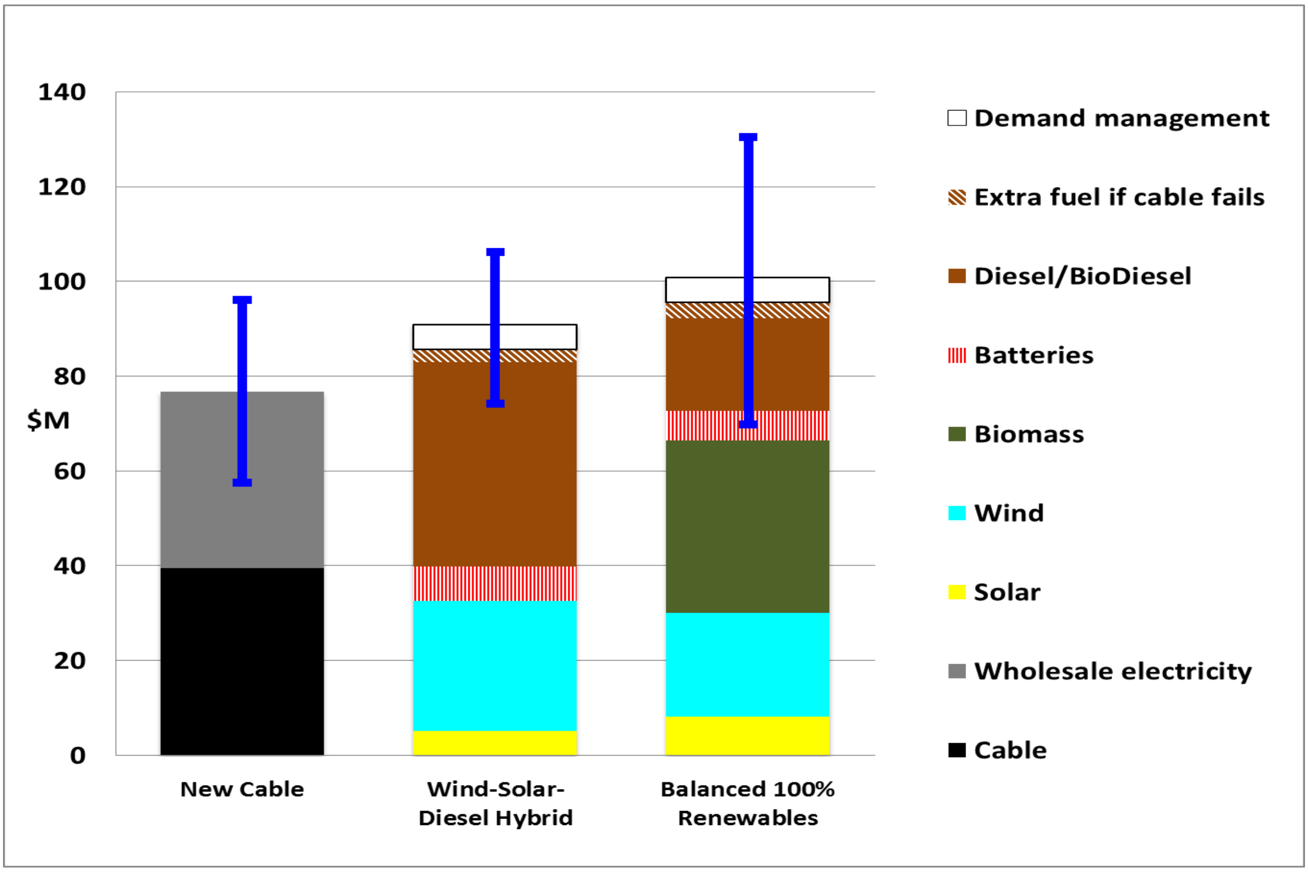
These cost estimates are based on a wide range of sources, including future grid electricity price projections and publicly available data not specifically tailored to Kangaroo Island's circumstances. Consequently, there is considerable uncertainty around scenario costs (up to +/-30%). The likely cost range could be reduced to an estimated +/-10% through a detailed engineering design and/or tender process. Such a process would likely take up to 12 months to complete.

The comparison of direct costs is also shown in Figure 1. The direct costs include capital and operating costs of the new cable and local supply, and demand management options, minus the value of Renewable Energy Certificates (RECs) generated by these options.

Figure 1: Direct costs of new cable and local power scenarios

(Net present value over 25 years;

Vertical blue bar indicates range of uncertainty)



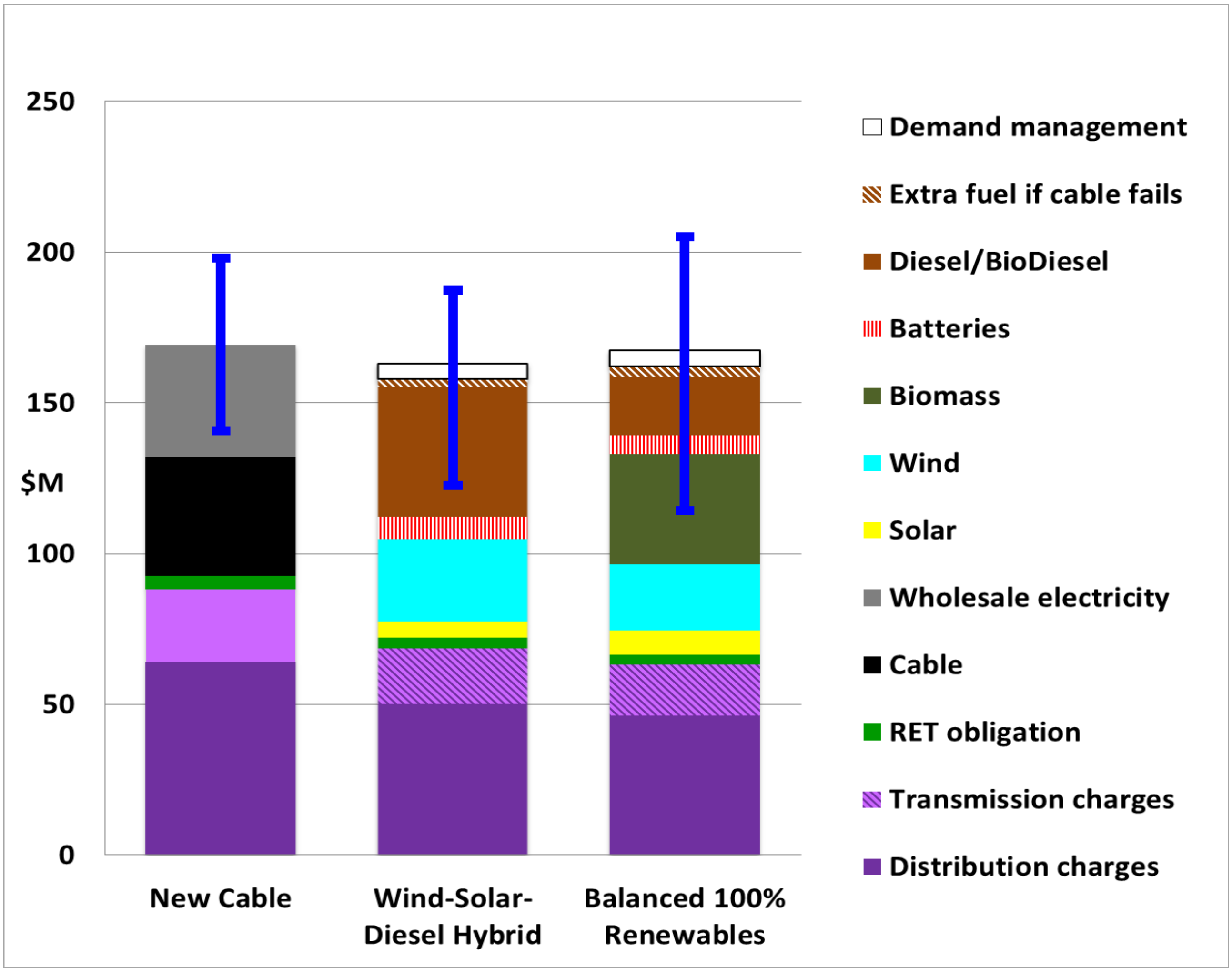
[4] As required by SAPN's assessment criteria, SAPN 2016, *Non-Network Options Report*, Section 7.2, "Such a non-network solution must be able to support total demand when the existing cable fails (i.e. islanded solution), thereafter for the whole evaluation period of 25 years".

The comparison of direct and indirect costs is shown in Figure 2. The indirect costs include network charges and mandatory Renewable Energy Target costs associated with the electricity supplied in each scenario. These costs are discussed in more detail in Section 3. The indirect costs are paid by Kangaroo Island customers, but are not required to be taken into account by SAPN in the RIT-D calculations. The reduced network charges in the local supply scenarios reflect the reduced volume of energy supplied via the distribution network, due to demand management and increased rooftop solar generation "behind the meter".[5]

Figure 2: Direct and indirect costs of new cable and local power scenarios

(Net present value over 25 years;

Vertical blue bar indicates range of uncertainty)



Other benefits of local electricity supply

There are also other benefits of supporting the development of local power supply and renewable energy on Kangaroo Island that have not been quantified in this study. These benefits include:

- enhanced local economic development and employment,
- reduced carbon emissions,

[5] Note that these reduced network charges would not reduce SAPN's total revenue during the current regulatory period and would be recovered by a slight increase in network charges across its service territory.

- reduced exposure to a single point of network failure,
- enhancing Kangaroo Island's clean and green brand,
- providing a high-profile, innovative, large-scale Australian case study for high-penetration decentralised energy, renewable energy and smart mini-grid control.

These benefits carry significant economic potential and are consistent with current South Australian Government policy objectives. Adopting a local renewable power supply strategy in a popular, iconic location like Kangaroo Island is likely to attract much international attention. It is likely to be recognised as a leading demonstration project with potential to catalyse other major investment activity in this area.

Assessing and managing risk

Cost is not the only relevant criterion for assessing supply options for Kangaroo Island. Reliability, risk and community acceptance are also crucial. The New Cable Scenario presents a straightforward technical solution, and a well understood level of risk and reliability. By contrast, the local electricity supply scenarios involve a relatively complex mix of wind, solar, battery, demand management, diesel and possibly biomass technology. These would need to be configured to be able to operate as an isolated mini-grid. While such technologies have all been well demonstrated in Australia and overseas, such an approach at this scale in place of grid asset replacement would represent a major precedent and innovation in the Australian context.

The short timeframe to implement such comprehensive local supply solutions is also challenging. The practical lead times required to develop, assess, approve and construct local wind generation and to establish a biomass supply chain and generator would almost certainly extend beyond the December 2018 deadline stipulated by SAPN in its RIT-D assessment process. It would be prudent to allow at least four years for these facilities to be operational.

On the other hand, it is reasonable to expect that solar, battery and diesel facilities could be established well before December 2018, the date when the new submarine cable would be completed. The use of local resources would enhance supply reliability in the period prior to the proposed new cable completion, and could secure reliability between December 2018 and the completion date for wind and potentially biomass generation (2020-2021). The cost of diesel generation in the event of the failure of the existing cable during this period is included in the local supply scenario cost estimates above. These estimates use a risk-weighted calculation as described in Section 2.3.

Just as it is possible that the existing undersea cable could fail before December 2018, it is also possible that the existing cable could continue to operate well beyond its expected design life of 2023. The longer the existing cable lasts, the lower the cost of operating diesel generation and therefore, the lower the cost of the Wind-Solar-Diesel Hybrid and Balanced 100% Renewables Scenarios. The continued operation of the existing cable could also facilitate the export of surplus wind energy to the mainland with commensurate additional benefits for the Kangaroo Island economy. These benefits are also estimated in Section 2.3.

It should also be noted that even a new cable can fail at any time during its design lifetime[6], so the Cable Solution also carries a risk of failure that is not costed in Table 1. The local electricity supply scenarios are more complex than the New Cable scenario, but could also offer significant reliability benefits because they are not dependent on a single source of supply. The value of this reduced risk should also be considered.

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[6] Consider for example of Basslink, which recently failed only 10 years into its 60-year design lifetime.

Non-technical barriers to local supply solutions

The above discussion addresses some key technical and financial risks associated with the different supply scenarios. However, the most significant barriers to developing a local electricity supply are probably non-technical, and relate to the regulatory, governance and business model regime. Some of these key non-technical barriers are discussed briefly here.

Firstly, there is the issue of how various risks are allocated. Given its innovative nature, the local electricity supply option is likely to be perceived as carrying significant additional risk. SAPN has an obligation to ensure reliable supply of electricity on Kangaroo Island and is subject to significant financial penalties if reliability falls short of specified targets. Adopting a local electricity supply solution introduces numerous unfamiliar new elements that need to be managed by SAPN to maintain reliability, along with consumer protection issues. These are examined in Section 5.2. A single new cable owned directly by SAPN would be much simpler to manage.

Secondly, the way that SAPN revenues are regulated by the Australian Energy Regulator (AER) means that it has strong long-term incentives to invest in new network assets, but relatively weak short-term incentives to support non-network options. For example, SAPN can earn a net financial return on investment in network assets (such as a new undersea cable) over the 30 to 40 year life of the assets. However, if instead of investing in a new network asset, SAPN incurs operating expenditure to support non-network local supply options, then at best it is permitted to retain the short-term capital savings of deferring a network investment. Indeed, SAPN may not even be permitted to recover the future cost of the non-network support. Such unbalanced incentives, combined with other regulatory barriers, obstruct SAPN from establishing an attractive business case to support non-network options, such as local electricity supply on Kangaroo Island.

Thirdly, the current RIT-D process does not ensure a balanced consideration of network and non-network options. Network businesses are required, and funded, to devote substantial resources to developing detailed network options, but such provisions seldom apply to developing non-network options. Such local alternatives are usually only developed by non-network option proponents at their own cost and risk. To provide a more balanced approach, detailed analysis of non-network alternatives, such as those described in this study, should be the rule rather than the exception.

Fourthly, if a local electricity supply option were to be adopted, and subsequently the existing cable from the mainland were to fail, then arrangements would need to be in place to ensure that the local electricity suppliers were not able to abuse their monopoly power to raise electricity prices unreasonably. However, there are contractual, ownership, governance and regulatory options available to manage these issues, including shared community ownership of generation assets and periodic tendering of retail services. However, to consult with and engage the community to develop a suitable model would require a significant investment of time and resources. The South Australian Government and the Kangaroo Island Council are two possible candidates who may be willing and able to lead such a process.

These institutional issues are discussed in more detail in Section 5.

Conclusion

This study finds that a balanced local electricity supply solution, including a potential transition to 100% renewable power, could provide a timely, reliable and cost-competitive alternative to a new cable linking Kangaroo Island to the mainland. The local electricity supply scenario would enhance the energy self-reliance of Kangaroo Island and is likely to deliver a range of economic development and other benefits to the local community. However, significant additional technical analysis, market testing and stakeholder and community engagement would be required to confirm costs and determine how a local electricity supply solution could be best configured.

A local electricity supply solution is only likely to be possible if it is strongly supported by the Kangaroo Island community, and is also supported by SAPN. In particular, for local generation to be cost competitive, SAPN funds earmarked for the new cable would need to be redirected to support demand management and local generation in the form of “network support payments” or similar arrangements. However, the current regulatory system creates a number of barriers to SAPN providing such support.

It is likely that SAPN will wish to complete its RIT-D assessment of supply options in line with its announced timeframe of December 2016. Despite the potential benefits of local renewable power supply, it also seems likely that SAPN will prefer the new cable option for meeting the future electricity needs of Kangaroo Island, due to:

- the non-technical barriers described above, including the constraints and incentives placed on SAPN by the current regulatory framework
- the limited amount of time and resources that have been available to assess local non-network alternatives
- the likely perception of higher risk by SAPN associated with local supply.

In this context, a local electricity supply solution seems unlikely to proceed unless there is strong support from the Kangaroo Island community, and unless a significant third party, such as the South Australian Government, the Australian Energy Regulator and/or ARENA, steps in to reduce the barriers to SAPN adopting a more innovative non-network solution. Potential roles for these and other stakeholders in driving the alternative solution are discussed in Sections 5.3, 5.4, and 5.5 in relation to network, generation, and retailing respectively.

Addressing such barriers in the context of Kangaroo Island would provide a powerful precedent for supporting local electricity solutions throughout Australia.

1 INTRODUCTION

1.1 BACKGROUND

Kangaroo Island's electricity is currently supplied through a submarine cable connected to mainland South Australia. As the cable is approaching the end of its design life, the owner of the cable, SA Power Networks (SAPN), is considering options for future supply for the island. SAPN is in the process of undertaking a Regulatory Investment Test – Distribution (RIT-D) to determine the best solution for future supply for the island.

As part of the RIT-D request, SAPN sought proposals for non-network alternatives to the network option of building a replacement submarine cable from the mainland at an estimated cost of $45 million (+10%/-50% – that is, between $22.5 and $49.5 million).

This ***Towards 100% Renewable Energy for Kangaroo Island*** research project aims to support and complement the RIT-D non-network proposal process by providing a quantitative and qualitative assessment of local power supply for Kangaroo Island. This assessment is intended to provide a timely analysis in order to inform proponents and to build community and South Australian Government understanding of possible renewable energy (RE) options.

This project assesses the costs and benefits of a mix of renewable energy, demand management, energy storage and supporting diesel or biodiesel generation to meet the current and foreseeable future energy needs of the Kangaroo Island community. It seeks to do this while improving reliability and flexibility, and without increasing energy bills. If implemented, local renewable electricity supply on Kangaroo Island would be a landmark in the development of renewable energy in Australia and would be a signpost to a future 100% renewable electricity system for Australia.

The assessment includes the short-term and long-term potential costs and benefits for Kangaroo Island customers and for SAPN, compared to investing in a replacement cable. The sharing of costs and benefits depends on the regulatory framework, and potential regulatory pathways are considered.

This report sets out:

- the scenarios examined and the results of the modelling
- a qualitative assessment of energy costs in the future
- an assessment of maintaining reliability under future scenarios
- an examination of the connection and network access.

This chapter examines the background to the project, including:

- the nature of Kangaroo Island electrical supply
- the current RIT-D process being undertaken by SAPN.

1.2 KANGAROO ISLAND

Kangaroo Island lies off the coast of the mainland of Australia near Adelaide and is part of the state of South Australia. Kangaroo Island is Australia's third-largest island, after Tasmania and Melville Island. It has a land area of 4,405 km^2, larger than the combined areas of Luxembourg, Singapore and Bahrain. One of the major industries is tourism, and the island has more than 200,000 visitors per year. The island has approximately 4,500 permanent residents. The largest town is Kingscote with a population of almost 2,000. Figure 3 shows a map of the island, and its position relative to the South Australian mainland.

Figure 3: Map of Kangaroo Island[7]

Currently, Kangaroo Island is connected to the National Electricity Market (NEM) through a submarine 33kV cable from Fishery Beach on the mainland to Cuttlefish Bay on Kangaroo Island, near the town of Penneshaw. A map of the existing high voltage electrical infrastructure of the island can be seen in Figure 4.

Figure 4: Electrical infrastructure on Kangaroo Island (33 kV network in green[8]**)**

The power supply cable from the mainland was energised in 1993 and has a design life of 30 years (until 2023), with an electrical rating of 10 MVA. As the cable is approaching the end of its expected life, SAPN is looking at augmentation options to ensure continued reliable supply of electricity to consumers on the island.

[7] Map sourced from Australian Travel and Tourism Network: www.atn.com.au/sa/south/kangarooisland-map.html
[8] SAPN (2105) Annual Planning Report, p. 258.

The RIT-D process

SAPN has identified a network option of replacing the existing submarine cable with a new 33 kV submarine cable from Fishery Beach to Cuttlefish Bay. This cable would have a rated capacity of 20 MVA, with the potential to be upgraded to a higher voltage of 66 kV, with a resulting increased capacity of 40 MVA. The estimated cost of this cable replacement is $45m with significant uncertainty (+10%, -50%) due to the range of indicative quotations received by SAPN.

Under clause 5.17 of the National Electricity Rules, SAPN is required to undertake a RIT-D process as part of evaluating the augmentation options. This is a regulatory test which aims “to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity”.[9]

As part of this process, SAPN has sought submissions from third parties on how best to continue electricity supply to the island. It is requesting submissions on the best way to meet the island’s supply needs through non-network solutions. A non-network solution in these circumstances would involve the island being able to meet its own energy needs without a replacement cable.

Under the RIT-D process, SAPN needs to consider whether support payments to one or more non-network project proponents will provide an option that maximises present value. A final decision on the preferred option to meet the identified need will be made in the final Project Assessment Report. For its analysis, SAPN has indicated that it is following the timeline outlined in Table 2.

Table 2: Planned timeline of the RIT-D process.[10]

Milestone	Date
Issue of Non-Network Options Report (NNOR)	Friday 15 April 2016
Information Session (Q & A)	Monday 16 May 2016
Latest date for Final Proposal Submissions to NNOR	Friday 15 July 2016
Expected date for publication of Draft Project Assessment Report (DPAR)	October 2016
Expected date for publication of Final Project Assessment Report (FPAR)	December 2016

[9] National Electricity Rules, Clause 17.17.1(b).

[10] SAPN (2016) Non-Network Options Report: Kangaroo Island Submarine Cable.

2 ENERGY SUPPLY SCENARIOS

2.1 METHODOLOGY

The analysis of supply options for Kangaroo Island has been undertaken using two different energy models: the commercial software Hybrid Optimization of Multiple Energy Resources (HOMER)[11] and the RE24/7 model, which has been developed by ISF staff.[12] This allowed us flexibility to add helpful bespoke features to the RE24/7 model, while cross-validating the results obtained by both models to ensure that the analysis follows accepted industry norms.

Table 3 discusses some areas of difference between the models to indicate their relative strengths.

Table 3: Feature comparison between HOMER and RE24/7 modelling software

Feature	HOMER	RE24/7
Models of renewable generation	Sophisticated models including automatic "typical year" solar profiles	Basic models with time series developed manually for solar and wind generation
Models of diesel and biodiesel generation	Sophisticated and richly featured models based on years of user experience	Basic models with assumptions suitable only for a first-pass analysis
Battery operation	Limited choice of operation regimes with batteries used for balancing not energy shifting	Batteries used to store surplus RE and supply residual load
Reliability	Ability to specify contingency reserves	System reserves specified manually with calculated system adequacy measures
Financial analysis	Net present cost in total and per generation technology	Discounted cash flow over modelling period with explicit RECs and other local features

[11] HOMER is an energy modelling software package for designing and analysing hybrid power systems. A trial version of the software can be downloaded free at the website: http://www.homerenergy.com/ .

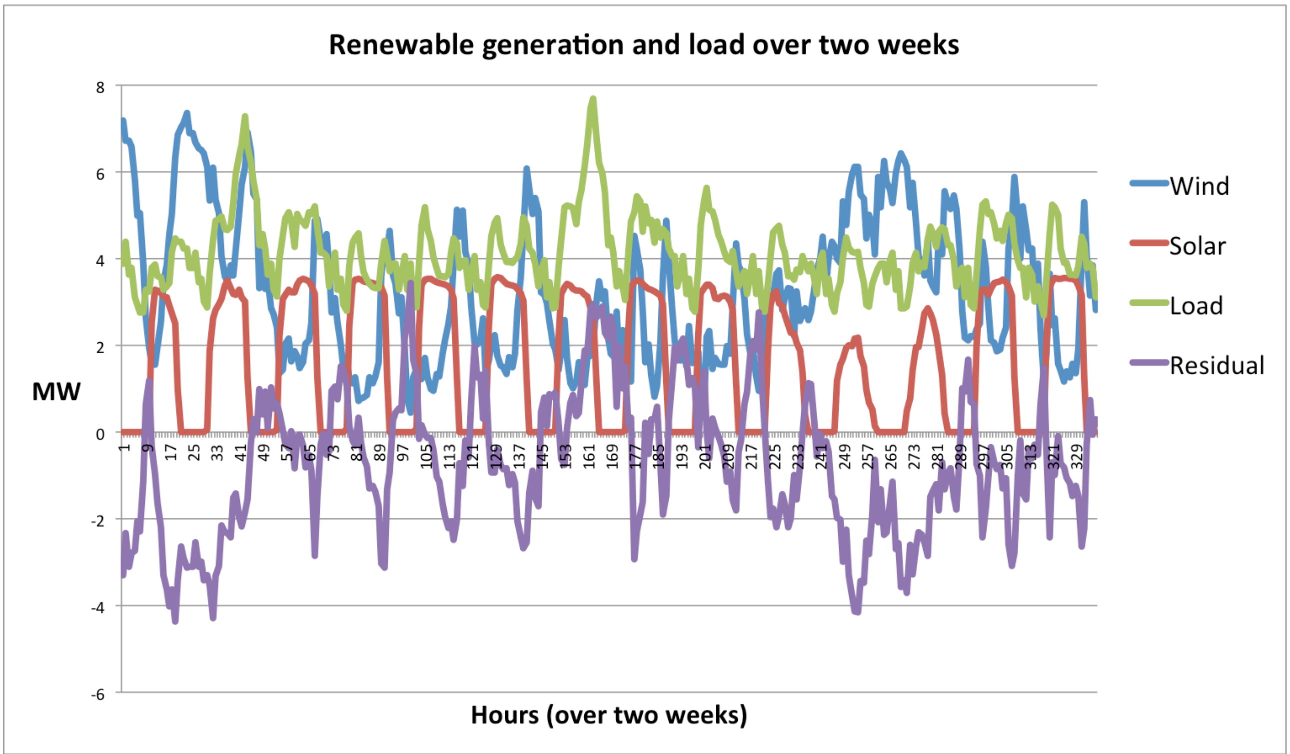
[12] RE24/7 is based on [R]Evolution which was developed in a thesis by ISF Research Principal Dr Sven Teske (2015), 'Bridging the Gap between Energy-and Grid Models: developing an integrated infrastructural planning model for 100% renewable energy systems in order to optimize the interaction of flexible power generation, smart grids and storage technologies', University of Flensburg, Germany.

Our modelling approach used HOMER and RE24/7 in a complementary way, with the general process outlined as follows:

- Develop models for several supply scenarios (defined in the next section) using RE24/7 to ensure the generators can supply the Kangaroo Island demand through a single modelled year at hourly intervals.
- Implement the same scenarios in HOMER and use this software's sensitivity and optimisation tools to explore the cost impacts of changing capacities of each energy supply or storage technology.
- Select preferred supply mixes for each scenario based on cost, curtailment, likely community appeal, and potential for continuous 100% renewable supply.
- Model the same supply mixes in both RE24/7 and HOMER to cross-validate on the basis of cost and energy output per technology.

A significant level of curtailment of wind and solar generation was accepted in order to achieve a high renewable energy fraction. Figure 5 shows two weeks of wind, solar and load on Kangaroo Island. This assumes 8 MW of wind capacity and 6 MW of solar PV capacity in addition to the existing rooftop solar PV generation, corresponding to the "Balanced" scenario described below. Load data are scaled to account for load growth to 2017. The residual is negative when wind and solar generation exceed load, leading to curtailment of generation. Curtailed wind and solar energy that is not used to supply load cannot earn REC revenue and this is reflected in the net present costs for these technologies.

Figure 5: Wind, solar and load on Kangaroo Island over two weeks



For more detailed discussion of the modelling approach please refer to Appendix A4.

2.2 INTRODUCTION TO SCENARIOS

This chapter examines the scenarios that have been modelled to explore future supply options for Kangaroo Island. Here, we briefly describe the scenarios used. Section 2.3 shows the net present cost results and the energy output from each generation technology used. Section 2.4 examines each scenario in turn, with a description of the technologies used.

To gain a greater understanding of the implications of 100% RE on Kangaroo Island we have modelled five different groups of scenarios. These are:

- **Scenario group 1:** Construction of a replacement submarine cable connection to mainland
  - Scenario 1a: Sourcing mainland wholesale electricity
  - Scenario 1b: Sourcing mainland 100% renewable electricity
- **Scenario group 2:** Powering the entire island through diesel generation
  - Scenario 2a: Using conventional diesel fuel
  - Scenario 2b: Using renewable biodiesel fuel
- **Scenario group 3:** Simple decentralised energy solution using solar and wind generation
  - Scenario 3a: Backed up by diesel with a short-term "balancing" battery
  - Scenario 3b: As above (Scenario 3a) with demand management (including energy efficiency and peak load management)
- **Scenario group 4:** Deployment of 100% renewable generation
  - Scenario 4a: Renewable energy supply with an longer-term "energy-shifting" battery
  - Scenario 4b: Renewable energy supply with biomass generation (using existing local plantation resources) and a balancing battery
  - Scenario 4c: Renewable energy supply with biodiesel and a balancing battery
- **Scenario 5:** Balanced combination of wind, solar, biomass, and biodiesel generation
  - This scenario models a staged introduction of new generation resources due to the range of approval and procurement times involved.

All local generation scenarios, except 3A, include the estimated impact of demand management on both the energy demand and the new generation capacity needed to meet the anticipated growth in peak demand. Demand management opportunities on the island are likely to be cost effective alongside local generation that is augmented incrementally with demand growth, because they would reduce the requirement for both generation capacity and fuel. Demand Management is not anticipated to be implemented alongside investment in a new submarine cable connection, because it would only reduce the amount of wholesale electricity purchased, and not offset the capital cost of the cable replacement.

2.3 SUMMARY OF RESULTS

Direct Costs

We undertook a high-level cost comparison of the different scenarios using the RE24/7 model, cross-validated with the commercial HOMER software to ensure the results are compatible with standard micro grid analysis. The modelled costs for the different scenarios include:

- capital costs for the construction of the cable or for generation on the island
- operational costs for generation, including fuel costs where applicable

- wholesale energy costs for any imported energy to the island from the mainland grid
- costs and benefits related to the longevity of the existing submarine cable.

The cumulative direct costs of the different scenarios over 25 years as derived by the RE24/7 modelling can be seen below in Figure 6, and the corresponding annual energy outputs per technology are charted in Figure 7. The numerical data are given in Table 4 and Table 5. These are net present costs in constant-dollar terms (no inflation) assuming a 7% discount rate.

Wholesale electricity and diesel fuel costs are a significant influence on the costs, and the relative costs, of the scenarios presented. They are also subject to significant future uncertainty. No detailed forecasting was attempted for this analysis; rather, the wholesale electricity cost was assumed to be constant at $67.1/MWh based on the ASX Futures market for September 2019, and the diesel fuel cost was assumed constant at $1.22/litre based on a recent study of diesel power generation in South Australia. These and other input assumptions are listed in detail in Appendix A3.

In our modelling, we have included the potential Renewable Energy Certificate (REC) revenues from each renewable generator as a negative operational cost of running that generator. For example, the cost shown for wind power is the sum of the capital cost and operational cost minus the expected REC revenue. The Renewable Energy Target (RET) and the way it has been modelled in this project is explained in more detail in Section 0. The REC price to 2030 was assumed constant at $57.0/MWh based on the ASX Futures market for January 2021.

Cable Contingencies

Proponents are required by the SAPN Non-Network Options Report to propose solutions for reliable power supply from December 2018. The Scenario 3 and Scenario 5 options include an estimated cost of managing the risk of cable failure in 2019 or 2020, calculated as the diesel fuel and operating expenditure to supply the load until new wind and biomass local generation resources are operational, which is assumed to be in 2021. The Scenario 4 options do not include this cost because they are presented as illustrative options rather than viable supply options. Scenario 4A and 4C do not have diesel back up, while 4B is essentially a variant on Scenario 3B, with mineral diesel fuel replaced by biodiesel.

Conversely, all scenarios with renewable generation include the estimated revenue from selling surplus generation to the wholesale market, weighted by the likelihood that the cable will remain in service until or beyond its design life of 2023. This revenue, and the cost of managing the risk of cable failure, are both weighted according to the probability that the cable will fail. In the absence of more reliable estimates, we have assumed the probability of cable failure to be 10% in each year from 2017 to 2026. The cable's 30-year design life runs until 2023.

To illustrate how cable contingencies are costed, Table 6 shows contributing annual costs and savings for Scenario 3B, the Wind-Solar-Diesel Hybrid power supply, for the possible life of the existing cable from 2017. The first three rows show our estimated likelihood that the cable will fail in or before each year, the cost of additional diesel fuel in each year prior to full installation of renewable energy supply, and the cost weighted by the likelihood. In this scenario, the wind generation is assumed to be fully installed in 2020, so the additional cost will be incurred prior to that year. Should the existing cable fail in 2017, there is no additional cost of fuel compared to the New Cable scenario, because a new cable would not be operational until 2018. The weighted costs, when calculated as a net present value, sum to $2.63 million as is shown in Table 4 for this scenario. Similarly, the remaining rows of Table 6 show our estimated likelihood that the cable will survive until each year, and the revenue from exporting- surplus generation and the savings in diesel fuel enabled by the cable in that year, both weighted by the likelihood. As a net present value they sum to $3.83 million as is also shown in Table 4 for this scenario.

Figure 6: Scenario costs (Net present value over 25 years, $M)

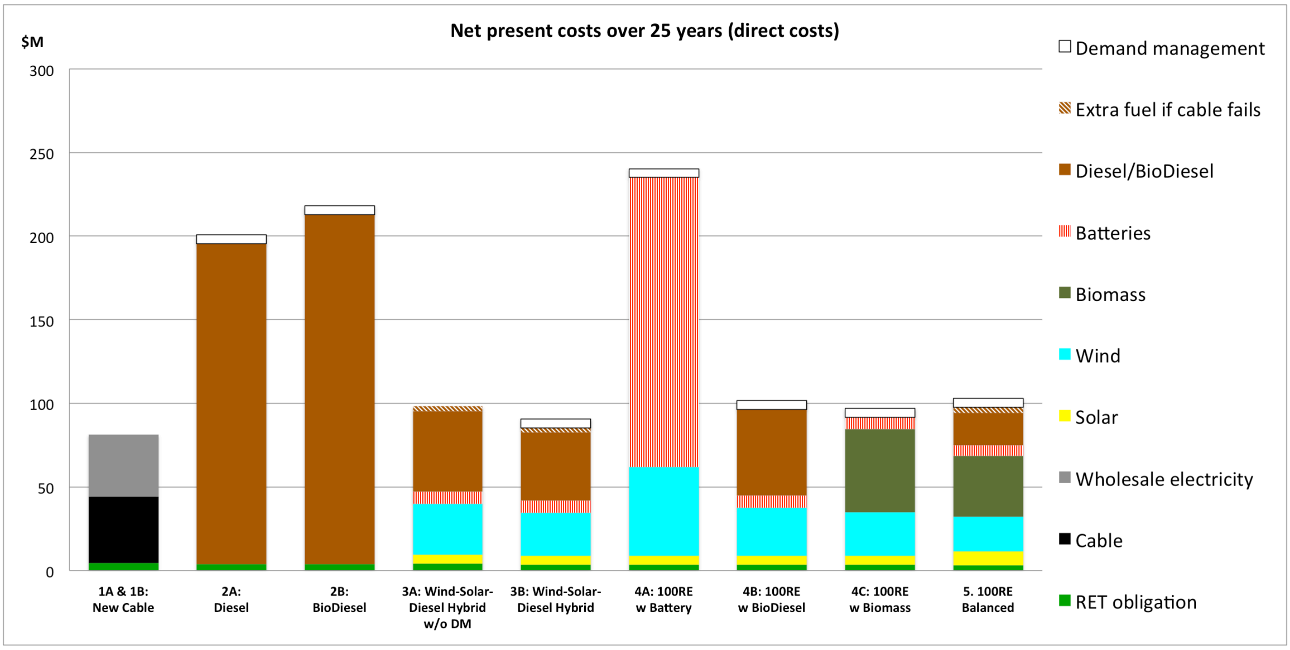


Table 4: Scenario Costs per technology (Net present value over 25 years, $M)

Scenario	1A	1B	2A	2B	3A	3B	4A	4B	4C	5
Solar					5.19	5.19	5.19	5.19	5.19	8.23
Wind					32.12	27.43	53.37	28.82	26.07	21.93
Batteries					7.32	7.32	173.1	7.32	7.32	6.38
Biomass									49.73	36.32
Diesel			191.7		50.63	43.12				
Biodiesel				209.1				51.53		19.38
Demand management			5.23	5.23		5.23	5.23	5.23	5.23	5.23
Wholesale electricity	37.22	61.19								
Cable	39.54	39.54								
Cable fails 2018-2019 (risk weighted cost)					3.02	2.63				3.45
Cable fails 2020-2026 (risk weighted benefit)					-4.31	-3.83				-1.19
Total	76.76	100.7	196.9	214.3	93.98	87.08	236.9	98.08	93.53	99.75

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Figure 7: Scenarios Energy production (MWh/year)

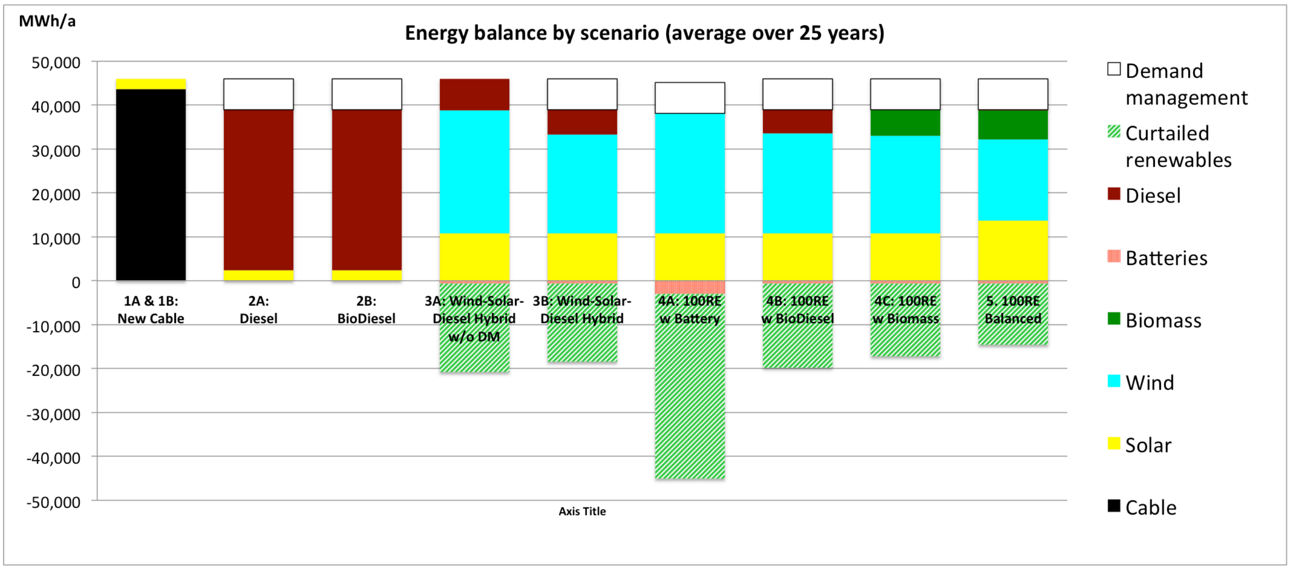


Table 5: Scenario average energy outputs per technology (GWh p.a.)

Scenario	1A/1B	2A/2B	3A	3B	4A	4B	4C	5
Solar	2.39[13]	2.39	10.86	10.86	10.86	10.86	10.86	13.66
Wind			27.93	22.47	27.24	22.71	22.18	18.56
Batteries			0.674	0.658	3.01	0.650	0.665	0.629
Biomass							5.89	6.58
Diesel		36.53	7.23	5.61				
Biodiesel		36.53				5.37		0.122
Cable	43.62							
Total	46.01	38.92	46.01	38.92	38.92	38.92	38.92	38.92
Curtailment			20.15	17.84	42.06	19.15	16.57	13.98
RE fraction	5.2%[14]	6.2%[15]	84.3%	85.6%	100%	100%	100%	100%[16]

[13] This is the modelled output of the 1.7 MW of solar PV generation that is already installed on the island.

[14] This only includes the local renewable electricity fraction; does not include the share of renewable energy in the mainland supplied electricity.

[15] If renewable biodiesel is used instead of conventional diesel, then the renewable energy share is 100%.

[16] Costs for biodiesel are used in scenario 5, so it is 100% renewable energy. Note that even if conventional diesel is used, the renewable energy fraction is still a very high 99.7%.

Table 6: Method to estimate cost if cable fails and benefit if cable survives

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025
Likelihood of failure	10%	20%	30%	40%	50%	60%	70%	80%	90%
Extra fuel consumption if cable fails early ($M)		6.05	6.05						
Weighted by likelihood of cable failing ($M)		1.21	1.82						
Likelihood of survival	90%	80%	70%	60%	50%	40%	30%	20%	10%
Revenue from selling surplus generation if cable survives ($M)				0.97	0.97	0.97	0.97	0.97	0.97
Weighted by likelihood of cable surviving ($M)				0.58	0.48	0.39	0.29	0.19	0.10
Savings in fuel if cable survives ($M)				1.61	1.61	1.61	1.61	1.61	1.61
Weighted by likelihood of cable surviving ($M)				0.96	0.80	0.64	0.48	0.32	0.16

Estimating Costs to Kangaroo Island Community

Only direct costs are formally assessed by the RIT-D process. However, likely costs to the Kangaroo Island community are an important additional consideration in situations where they are affected by the proposed network or non-network solution. Were the existing submarine cable to fail, without a replacement cable to Kangaroo Island, the price regime applying to customers would depend on a negotiated outcome to manage the transition away from the present regulated regime. This is further discussed in Section 5.

To attempt to estimate the costs facing Kangaroo Island customers via electricity bills, we have assumed that Distribution and Transmission Use of System (DUoS and TUoS) charges would continue to apply. Although it could be argued that TUoS should no longer apply if the island produced its own power because it would not be benefitting the transmission system on the mainland, it could equally be argued that the DUoS should be increased to allow for the additional costs of operating an islanded network. Assuming the same network charges will apply seems a balanced approach. The electricity consumption on the island, like all electricity consumption across the National Electricity Market, also carries a RET liability that pays for REC revenues delivered throughout the country.

Figure 8 shows the cumulative costs of the different scenarios over 25 years, derived using these assumptions. From this viewpoint, the Local Wind-Solar-Diesel Hybrid Solutions represented by Scenarios 3B and 5 are similar or slightly cheaper than the Cable Solution.

If the island wished to market itself as having 100% renewable energy, it may need to surrender its REC certificates rather than sell them. This would imply a higher cost borne on the island. The REC revenues from all renewable generators are also summed and shown as a separate item in Figure 9. If the island decides to surrender its REC certificates without financial reward, this summed “foregone revenue” should be added to the total cost of each scenario, because the technology costs already incorporate the REC revenue, as discussed above.

Figure 8: Net present costs over 25 years including network and RET charges

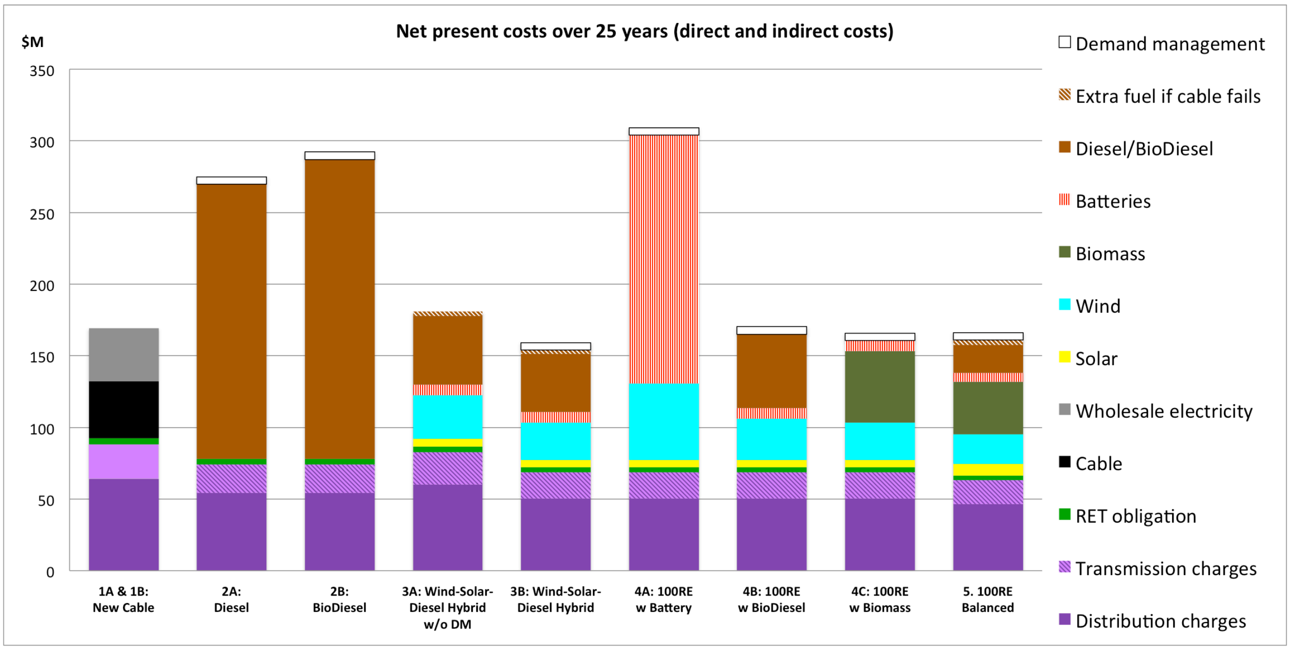
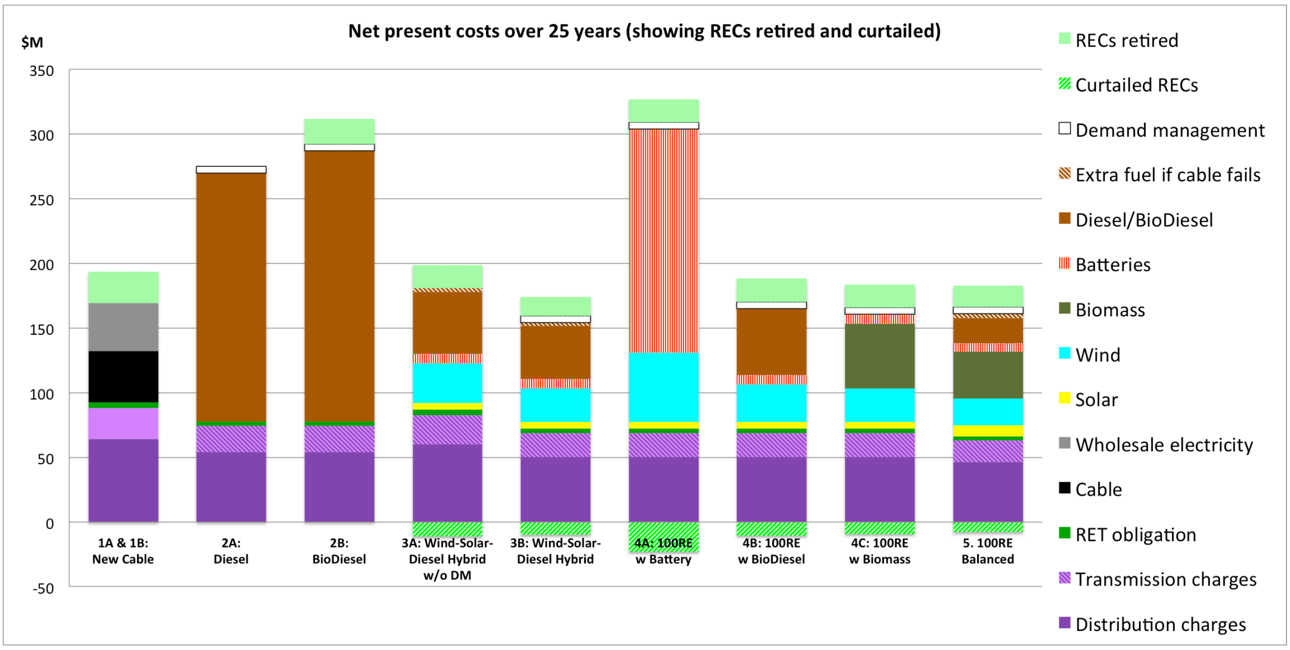


Figure 9: Net present costs over 25 years including RECs retired and curtailed



Renewable energy generators that are under-utilised, but would have been capable of generating if load was higher, do not generate RECs for that part of their output that is not used. These foregone certificates are referred to as “curtailed RECs” and, for the purpose of comparison, are shown below the axis in Figure 9. While the cable remains operational, any excess renewable generation is delivered to the wholesale market and there are no curtailed RECs.

Table 7 shows the numerical data presented graphically in Figure 8 and Figure 9.

Table 7: Additional costs per scenario affecting the community ($ million net present cost)

Scenario	1A	1B	2A	2B	3A	3B	4A	4B	4C	5
DUOS	64.22	64.22	54.25	54.25	60.26	50.28	50.28	50.28	50.28	46.32
TUOS	23.87	23.87	19.99	19.99	22.33	18.45	18.45	18.45	18.45	16.91
RET obligation	4.50	4.50	3.77	3.77	4.21	3.48	3.48	3.48	3.48	3.19
REC revenue	0.00	23.98	0.00	19.23	17.75	14.87	17.68	17.82	17.82	16.34
RECs curtailed	0.00	0.00	0.00	0.00	11.01	9.75	22.99	10.47	9.05	7.64

2.4 SCENARIOS

Scenario 1: Replacement Network Cable

This scenario shows the preferred network solution proposed by SAPN, which is to replace the existing cable before the end of its design life with another 33 kV cable. The new cable would be capable of operating at 66 kV as part of a future upgrade to increase its capacity.

Note that we have included an estimate of the wholesale electricity cost over the forward period, as discussed in Section 2.3. This is because the value from any non-network solution will include not just the deferral of network investment, but forgone imports of electricity from the South Australian NEM wholesale market. Therefore, an estimate of this value is included so this scenario can be directly compared with the non-network solutions outlined below.

We have split this scenario into two sub scenarios. Scenario 1A looks at the cost of replacing the existing cable, and keeping supply from the NEM using current policies. Scenario 1B examines the potential of sourcing 100% renewable energy from the mainland over the new cable. Scenario 1B is not separately graphed but is shown in Table 4. The premium cost of renewable energy from the mainland is estimated by the value of the large-scale generation certificates (LGCs) that would need to be purchased for the wholesale energy that would be imported. This value corresponds to the “RECs retired” shown in Figure 9.

Scenario 2: Diesel Generation

This scenario examines the cost of supplying the island entirely with diesel generation, as a non-network solution at the end of the life of the existing cable. We are not suggesting that this would be a preferred alternative, but have included this scenario for comparison, and to highlight that a diesel solution could be implemented quickly to meet reliability requirements. We consider that supply on the island could be maintained with approximately 10 MW of generation in 2017, increasing to 14 MW by 2041 to meet load growth. This provides redundancy, allowing a unit to be offline for maintenance.

Diesel generation installed under this and all subsequent scenarios comprises diesel engines capable of long-duration running. The existing diesel power station is intended for contingency use only, and its engines are not designed for long-duration running.

We have split this scenario into two separate sub scenarios. Scenario 2A looks at supplying the island solely through conventional diesel while Scenario 2B looks at supplying the island through biodiesel. The usage of biodiesel is explained in Section 4.2. Scenario 2 is the most expensive scenario examined, with a large portion of the costs being the assumed price of the diesel or biodiesel fuel.

Scenario 3: Wind-Solar-Diesel Hybrid

This scenario examines the cost of supplying the island largely with embedded energy sourced from the island itself as an alternative to replacing the cable. The scenario is intended as a conservative option for locally sourcing power using renewable generators that are already prevalent in Australia (and particularly in South Australia). While largely using renewable generation, diesel generation is included to provide power when the renewable resource is not sufficient to meet the instantaneous demand; it also acts a contingency reserve. A short-duration balancing battery (0.5 hours discharge capacity) is included to help manage ramp rates and to reduce the need for low-load running of the diesel generators. Experience of high-penetration renewable power stations elsewhere in Australia, such as those operated by Horizon Power[17], has shown that short-duration energy storage is desirable when diesel generators are required to balance the combined variability of load and wind or solar generation.

Wind generation is assumed to comprise several moderately large turbines with capacity 1-2 MW, similar to those that can be seen by Kangaroo Island residents on the nearby Starfish Hill wind farm. The 2017 capacity of 8 MW would require 4 to 8 single turbines most likely distributed between two locations with suitable network capacity to carry their output, such as in the vicinity of Penneshaw and the north coast near Kingscote. Solar PV generation is assumed to be divided between a 2 MW solar farm (occupying about 5 hectares, the equivalent of about 5 soccer fields)[18] and a further 2 MW of subsidized rooftop solar generation installed by customers (for example, 800 customer rooftops with an average of 5kW or about 20 solar panels each). This would be in addition to the existing 1.7 MW of rooftop solar.

For this scenario we have modelled two slight variations. Almost all of the non-network solutions are modelled with demand management programs in place, as described in Section 4.1, including Scenario 3B. Scenario 3A, however, looks at supplying the forecast demand on the island using embedded energy technologies alone, without demand management. This exception illustrates how the benefits of demand management exceed the costs, reducing energy consumption and hence the required generation capacity.

In both of these scenarios, Kangaroo Island is largely powered by renewable energy, to the order of 86% of energy supplied. We note that Scenario 3B is cost competitive with the installation of the cable in net present value terms, subject to the uncertainties in our cost estimates, which are indicated in Figure 1 and Figure 2.

Scenario 4: 100% Renewable Energy

This scenario looks at undertaking full 100% RE supply on Kangaroo Island as an alternative to the replacement of the cable. Three scenarios are examined. Scenario 4A uses batteries to maintain supply during periods when wind and solar resources are not sufficient. This requires "energy-shifting" battery technology and practices, which are different to the short-duration "balancing" batteries used for ramp-rate management in several other scenarios in this study. We note that this scenario results in a very large wind installation to reduce the duration of these generation deficit periods, and consequently this option also results in the highest level of generation curtailment. The oversizing of this wind generation is costly and inefficient from an economic perspective.

Unlike all the other scenarios modelled, this scenario has periods during the year when the full load cannot be met, resulting in an unserved load of 773 MWh in 2017 and 902 MWh in 2041. Therefore this scenario is therefore not viable as a reliable power supply, but it is presented here to provide an indicative scenario of renewable energy backed up by batteries alone. Lacking any

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[17] http://horizonpower.com.au/about-us/our-assets/marble-bar-and-nullagine-solar-power-stations/

[18] For comparison, the 20MW Royalla Solar Farm in the ACT occupies about 50 hectares, https://www.engineersaustralia.org.au/news/work-set-commence-act-solar-farm

other form of controlled generation, it would require a very large battery system to store enough energy for periods of sustained low wind and solar generation output. The lithium-ion battery assumed here may not be the appropriate technology for this scenario, because other energy storage technologies may have lower costs per kWh for a large energy-to-power ratio.

Scenarios 4B and 4C use biodiesel and biomass generation respectively, to maintain supply during periods when wind and solar resources are not sufficient. Section 3.1 discusses how these renewable energy supplies may be obtained on Kangaroo Island. Within the Scenario 4 grouping, biomass generation appears to be the most cost effective way to augment wind and solar generation to provide a 100% renewable energy supply. However, these scenarios don't account for the time required to approve, procure, and build all the renewable generation required, which for wind and biomass generation is longer than the 2018 requirement for full replacement of the cable supply. Nor does Scenario 4C account for the operational limitations of operating biomass generation in a high penetration RE system, about which there is little experience in Australia.

Scenario 5: "Balanced" 100% Renewables Scenario

The final scenario, Scenario 5, is intended to provide practical and cost-effective 100% renewable supply through a staged build of new generation capable of meeting the island's full demand from 2018, transitioning to 100% RE by 2021. It can be seen by comparing Figure 6 and Figure 7 that biomass generation is cost effective compared to diesel or biodiesel generation, producing the same amount of energy for a much smaller cost, because of the readily available plantation resource on Kangaroo Island. Scenario 4C, however, has the shortcomings noted above.

Scenario 5 was developed as a more robust implementation of Scenario 4C. It includes 8 MW of diesel generation as a contingency reserve and to provide the flexible response that a biomass-fuelled steam turbine generator lacks. It also includes 2 MW of additional solar PV generation (giving a total increase of 6 MW to the island's solar PV capacity) and 2 MW less wind generation (8 MW in total) than Scenario 4C. This energy mix benefits from the complementary generation profiles of wind and solar generation that is commonly seen in the time series data; this complementarity is evident in the first week of data graphed in Figure 5. A 3 MW "balancing" battery is used in both Scenarios 4C and 5 to help manage ramp rates and reduce the necessity for low-load diesel or biomass operation.

These measures increase the cost of Scenario 5, compared to Scenario 4C, but they help to achieve a realistic investment transition strategy during the next few crucial years. Solar PV and (new long-running) diesel generation can be built relatively quickly and would be able to provide the necessary security of supply in the required timeframe to the end of 2018. Should the submarine cable fail in 2018, the new diesel generation would be in place to supply load, and the increased solar PV generation would reduce the diesel fuel requirement and therefore the financial risk. Meanwhile, a demand management program could be implemented progressively, and wind generation would be in advanced stages of planning and procurement. Therefore, a continual reduction in fuel requirement could be expected with a higher degree of certainty. Biomass generation would then be introduced, probably in a similar time frame to wind generation so that everything would be in place by 2020. From then on, the island would experience very little, if any, additional cost in the event of cable failure.

This build strategy provides reliable power in the event of cable failure from 2018, minimises the financial risk of such failure by placing an effective cap on diesel fuel consumption, and provides a diverse mix of renewable generation by the end of 2020 that is likely to be resilient to resource variability. More granular modelling (with a finer time step than hourly) is required to confirm this resilience and more generally the reliability of the Scenario 5 solution. This "balanced" scenario was modelled using the cost of biodiesel instead of conventional diesel fuel. As the diesel plant is minimally required, this is therefore low cost, and provides an effective path to 100% renewable energy by 2020.

2.5 CROSS-VALIDATION OF MODELS

To ensure that the analysis presented here follows industry norms, we modelled the same supply mixes in both RE24/7 and HOMER to cross-validate on the basis of cost and energy output per technology. Table 8 compares the annual energy output per technology, renewable energy fraction, and net present cost calculated by each model for Scenario 5 at the 2017 load level. Scenario 5 is chosen for this comparison because it includes all the generation technologies modelled. Note that Scenario 5 does not have a mix of capacities recommended by HOMER's optimisation of net present cost; rather, it was designed using the considerations described above.

Table 8: Comparison of outputs from HOMER and RE24/7 calculations for Scenario 5

Technology for Balanced scenario	Capacity *MW*	Output: RE24/7 *MWh in a year*	Output: HOMER *MWh in a year*
Solar PV (new)	6	12,320	8,771
Onshore wind	8	22,428	24,888
Batteries	3 (Balancing battery)	269 (throughput)	Negligible (throughput)
Biomass	5	7,162	29,157[19]
Diesel (new)	8	62	1,461
Wind curtailed		10,707	32,743[14]
		RE24/7	**HOMER**
Renewable fraction		99.86%	95%
Net present cost		$102M	$93M

[19] Note that the HOMER model builds in very little flexibility for the biomass generation, which drive this plant to continue to run a close to full capacity even while wind turbines are generating surplus energy relative to demand. These leads to over production of power from biomass and consequently significantly curtailment or "spillage' of surplus wind energy.

It is worth discussing the differences between modelling approaches in detail.

- RE24/7 used solar generation data for the full year 2010 estimated from satellite-derived insolation data, averaged over several representative sites in this part of South Australia. HOMER used a “typical meteorological year” of solar data for a point in the middle of Kangaroo Island. RE24/7 made more favourable assumptions than HOMER about orientation of solar panels. These factors taken together explain the difference in annual PV outputs.
- Identical wind energy time series were used for both models. HOMER includes a more advanced model for turbine performance and this may explain the small difference in annual wind output.
- There are many ways to schedule batteries and different approaches were used by RE24/7 and HOMER. The former used a simple control method for the battery, charging or discharging based on the residual load after wind and solar generation, prior to any dispatch of fuel-based generation. HOMER used a model that makes minimal use of the battery, with negligible throughput on the scale of MWh. Both models use much less than the potential throughput of the battery, consistent with it being a “balancing” battery not intended to be used for substantial energy shifting.
- The models use completely different approaches for biomass generation. HOMER applies a minimum loading of 80% and schedules periods during the year when the biomass generator is switched off. RE24/7 prioritises wind and solar energy and uses the biomass generator to supply residual load after it has been smoothed by the battery. In reality, the system control should observe a minimum loading for the biomass generator, which might be as low as 50% according to advice we have received from ERK Eckrohrkessel, a German company experienced in biomass projects. This could be achieved by turning it off for a period every day, according to the pattern of residual load, or by using a similar strategy to reduce the curtailment of wind and solar energy. The result is that HOMER has a much higher capacity factor for the biomass generator.
- Similarly, because RE24/7 prioritises wind and solar energy in its dispatch procedure, the annual diesel output is significantly less than with HOMER, and consequently the renewable energy fraction is very close to 100% when modelled by RE24/7. The diesel power plant comprises several individual units, explicitly modelled in HOMER as 2 MW each, so the overall minimum loading for the plant can be low compared to the minimum loading for a single diesel generating unit. Therefore, the minimum loading is ignored in the RE24/7 analysis.
- The net present cost is sensitive to a large number of parameters, which makes it sometimes unsuitable as an optimisation variable. In particular, in this analysis, the scheduling of investments in replacing ageing generators and batteries had a significant effect on the net present cost, and this, combined with relatively minor differences in input assumptions, led to a $9M difference between the two models.

Overall, while the inputs to the models were similar, the assumptions of the analysis methods in the models were significantly different, particularly the assumptions relating to dispatch of battery storage and biomass generation. This both explains the differences between figures in Table 8 and justifies the use of a bespoke model that accounts for specific project requirements. The results from RE24/7 are closer to what might be achieved by an optimal control strategy that manages biomass and diesel generation and battery operation so as to minimise curtailed wind generation. A detailed engineering study with specific design of each technology and the control strategy would be needed to achieve a more accurate analysis.

2.6 SUMMARY OF KEY SCENARIO COSTS

It is clear from the above discussion that of the ten scenarios considered, there are three of particular interest:

- 1A: The New Cable Scenario, as this the preferred network options as identified by SAPN
- 3B: The Wind-Solar-Diesel Hybrid Scenario, as this is the lowest cost of all local supply scenarios and of a comparable cost to the new cable option
- 5: The Balanced 100% Renewables Scenarios, as this is the most viable and cost competitive 100% renewable scenario considered.

The estimated costs and the range of uncertainty of these three scenarios are shown in.Table 9. These estimates are based on conservative assumptions about the current and future costs of renewable energy technologies and accounts for the cost of covering the risk that the existing cable may fail during the four years required to implement the Wind-Solar-Diesel Hybrid Scenario.[20]

Table 9: Estimated costs of new cable and local power supplies scenarios

Scenario	New Cable	Wind-Solar-Diesel Hybrid	Balanced 100% Renewables
Direct costs (NPV)	**$77 million**	**$87 million**	**$100 million**
Capital expenditure (amortised) Operating expenditure (less Renewable Energy Certificates)	$34 million[21] $43 million 0	$60 million $42 million (-$15 million)	$87 million $29 million (-$16 million)
Range of direct costs	$57-96 million	$70-102 million	$69-129 million
Direct & indirect costs	**$169 million**	**$159 million**	**$166 million**
Range of direct & indirect costs	$141-198 million	$119-184 million	$113-204 million

These cost estimates are based on a wide range of sources, including publicly available data not specifically tailored to Kangaroo Island's circumstances and projections of future. Consequently, there is considerable uncertainty around Scenario costs (up to +/-30%). Significant sources of uncertainty include the treatment of transmission charges (+20%/-100%), future wholesale electricity costs (+20%/-20%), the new cable (+30%/-30%), wind generation installed on Kangaroo Island (+30%/-30%), biomass generation not widely used in Australia (+50%/-50%), and demand management specifically tailored to Kangaroo Island loads (+20%/-50%). The estimated cost range could be reduced to about +/-10% through a detailed engineering design and/or tender process. Such a process would likely take up to 12 months to complete.

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[20] As required by SAPN's assessment criteria SAPN 2016 *NNOR*, Section 7.2, "Such a non-network solution must be able to support total demand when the existing cable fails (i.e. islanded solution), thereafter for the whole evaluation period of 25 years"

[21] The cable capital cost is $36 million, the centre of the range of uncertainty in the NNOR, amortised over a 35-year anticipated lifetime, and (as with all costs) is expressed as a net present cost over 25 years.

The comparison of direct costs is also shown in Figure 10. The direct costs include capital and operating costs of the new cable and local supply and demand management options, minus the value of Renewable Energy Certificates (RECs) generated by these options.

Figure 10: Direct costs of new cable and local power scenarios

(Vertical blue bar indicates range of uncertainty)

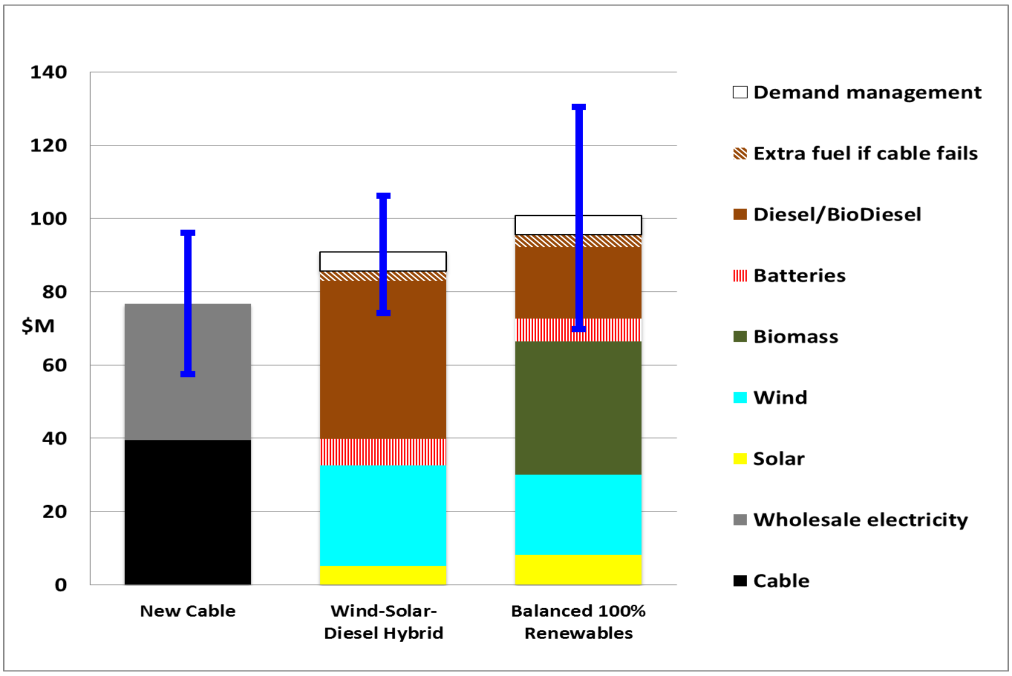
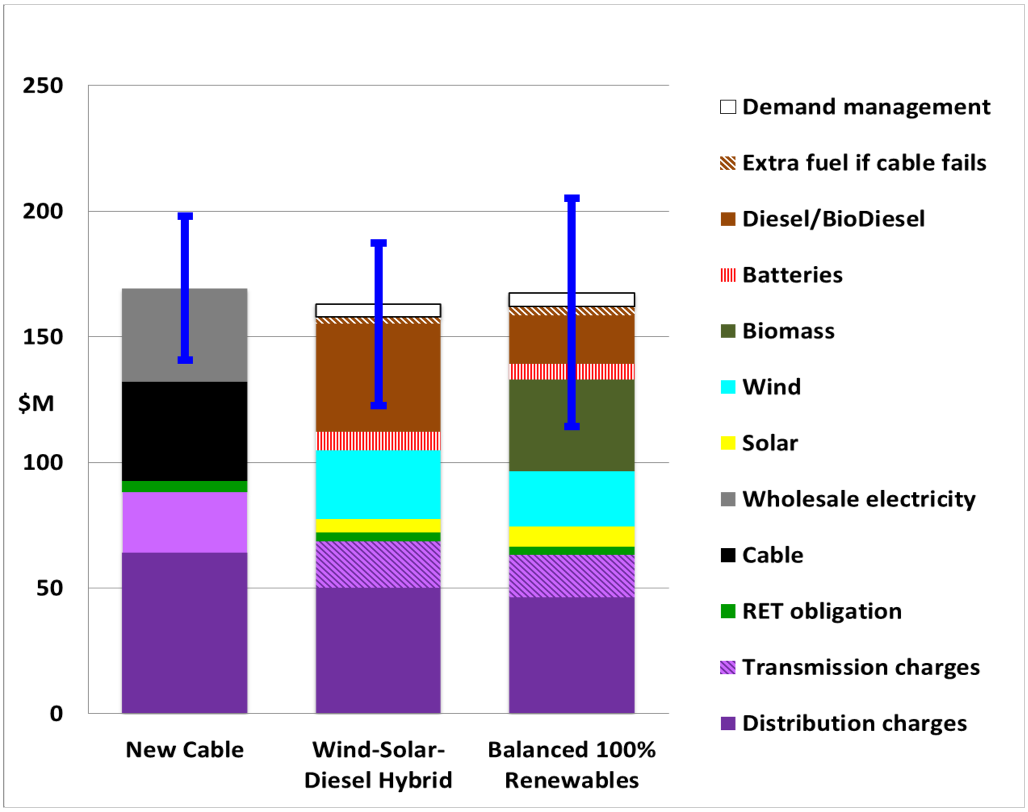


Figure 11: Direct & indirect costs of new cable and local power scenarios

(Vertical blue bar indicates range of uncertainty)



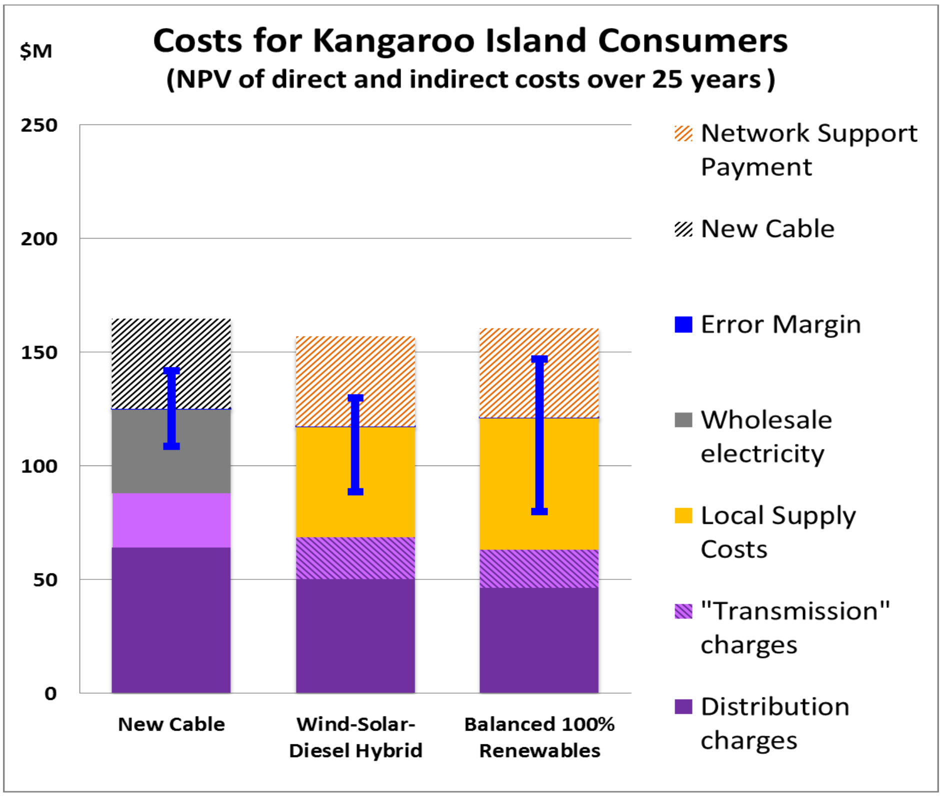
The comparison of direct and indirect costs is shown in Figure 11. The indirect costs include network charges and mandatory Renewable Energy Target costs associated with the electricity supplied in each scenario. The indirect costs are paid by Kangaroo Island customers, but are not required to be taken into account in the RIT-D calculations by SAPN. The reduced network charges in the local supply scenarios reflect the reduced volume of energy supplied via the distribution network, due to demand management and increased rooftop solar generation “behind the meter”. Note that these reduced network charges would not reduce SAPN’s total revenue during the current regulatory period and would be recovered by a slight increase in network charges across its service territory.

The net costs borne by Kangaroo Island consumers are illustrated in Figure 12. Local consumers would be required to pay for network charges in all three scenarios. In the New cable scenario, they would be required to pay the costs of wholesale electricity, but not the direct cost of the new cable as this would be borne by SAPN and recovered from all consumers over time across the state in network charges. Similarly, in the local supply scenarios, Kangaroo Island consumers would be required to pay the capital and operating costs of local generation and supply, net of the amount of “network support payments” made by SAPN to the local generators and demand management providers. As for the new cable costs, the cost of “network support payments” would be recovered from all consumers over time across the state in network charges.

To the extent that local electricity supply did achieve savings compared to the new cable scenario (such as the estimated $3 to $10 million shown here), these savings could represent a reduction in electricity bills for consumers on Kangaroo Island or a benefit that could be shared with other stakeholders, including SAPN.

Figure 12: Net costs borne by Kangaroo Island consumers

(Vertical blue bar indicates range of uncertainty)



3 LOCAL ENERGY OPTIONS AND COSTS

This chapter presents a qualitative analysis of the costs and opportunities that arise from the selection of a non-network solution rather than replacing the existing submarine cable.

3.1 RENEWABLE ENERGY SUPPLY

This section of the report describes general issues regarding different renewable energy supply technologies considered in the modelling for Kangaroo Island. These include:

- onshore wind
- solar photovoltaic
- biomass generation.

Detailed cost and physical assumptions about each generation technology are summarised in Appendix A3 and are not reproduced here.

Onshore Wind Generation

Under all of the scenarios modelled, wind energy is the primary source of renewable energy capacity installed, due to the excellent wind resource in this part of Australia's coastline.

The capability of a site is a function of the wind resource, the proximity of a generator to a location where it can be connected to the high voltage grid, access to appropriately zoned and owned land, and community acceptance. There are probably a number of good sites for the installation of wind power on the island, especially on the northern coast near Kingscote and the area surrounding Penneshaw, which are distant from national parks and, as can be seen in Figure 4, near the existing high voltage distribution system. The community is familiar with wind farms that are prevalent in this region of South Australia and would be supportive of an appropriately located wind farm that brought clear benefits to the island.

That said, Kangaroo Island may present a logistical issue for the deployment of wind power. Because the site is an island, project development of wind farms may be more expensive than it is in other locations. All the materials, including the towers and turbine blades, must be shipped to the island. Also, a large crane would have to be transported to the island in order to erect the turbines. Kangaroo Island is serviced by two large passenger and freight ferries. The larger of these ferries (the *Spirit of Kangaroo Island* shown in Figure 13) may be large enough for shipping wind turbines and a crane, but this would need to be confirmed.

For our modelling we used wind data compiled by ROAM as part of the Australian Energy Market Operator's 100% renewable energy study.[22] This study divided Australia into a set of polygons and used data to provide an estimate of the wind resource of each polygon, and time serious output profiles of a 1 MW wind turbine in a typical good location within that polygon.

[22] ROAM Consulting 2012, ROAM report on Wind and Solar modelling for AEMO 100% Renewables project

Figure 13: Trucks on the ferry to Penneshaw might carry wind turbine components[23]

Solar Photovoltaic (PV) Generation

Approximately 1.7 MW of installed solar PV capacity already exists on the island. Solar PV installations can be a combination of distributed small-scale systems at point of use, and large installations such as solar farms. The existing capacity is mostly connected behind customer meters; the largest existing single solar facility is at Kingscote airport where a system of 50 kW capacity is installed.

The load profile provided by SAPN is the loading on the submarine cable, which excludes load served by local generation on the island. Therefore, the estimated output profile from the existing solar PV is added to the load to produce the gross load profile that is used for this study.

We have assumed that any additional solar PV generation would be split 50/50 between utility-scale solar farms, and behind-the-meter integration onto the roof spaces of individual houses or businesses. The impact of potential reverse power flows in the distribution network has not been considered in this study. Behind-the-meter solar PV would generally be located where population and load is, predominantly in areas around Kingscote, while solar farms would be located where there is available land in close proximity to the 33 kV network.

A lower cost has been assumed for solar PV integrated at customer sites, because Small Scale Technology Certificates (STCs) would be claimed at the time of installation, and therefore we have not included additional REC revenues for this solar generation. This cost is included in the direct costs shown in Section 2.3, although it may in practice appear either as a full subsidy to encourage further uptake of residential solar PV, or as a partial subsidy, in which case some of the direct costs would be borne by customers.

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[23] https://www.flickr.com/photos/blackdiamondimages/16630320867

Biomass Generation

There are high quality biomass resources on Kangaroo Island, particularly timber plantations. Much of this timber has been planted for commercial wood chipping, but this proposed venture was subsequently found to be uneconomical. There are currently 4,000 ha of pine, and 15,000 ha of eucalyptus plantations.[24]

Figure 14: Eucalyptus stems on Kangaroo Island[25]

Logs from these plantations represent over 2.4 million green tonnes of wood available for bioenergy.[26] This has been estimated as being capable of supplying a 10MW generator for up to 17 years. As this level of generation is higher than anything we are modelling, we have assumed that the on-island capacity in woody fuels is enough to meet the required biomass over the modelled period.

We note that, in the long term, there are multiple options for the forestry land: a second crop of trees could be grown from the coppiced stumps, or the land could be de-stumped and returned to agriculture (cropping or pasture), or it could be used for an alternative forestry operation growing timber specifically for fuel (high density short rotation harvest cycles).

As such, we are confident that a biomass solution would not need to import fuel to the island. We note that efficiencies of scale mean that the construction of a single biomass generator is more practicable than multiple smaller generators. Indeed, one possible biomass solution proposed by Earth Systems was the construction of a single central generator on the island.[27] We consider that this generator would likely be best located near the main load at Kingscote. Earth Systems noted that such a generator would produce waste heat and proposed that this be used for process heat in making briquettes or creating biogas for export. Another option is to use the waste heat for producing desalinated water. It is outside the scope of this study to examine the potential for such schemes to generate revenue or other benefits for the island.

[24] Earth Systems, 2012, *Bioenergy Resource Analysis and Technology: Feasibility for Kangaroo Island* (Report to Renewables SA), p. 14

[25] Earth Systems, 2012, p. 14

[26] Earth Systems, 2012, p. 15

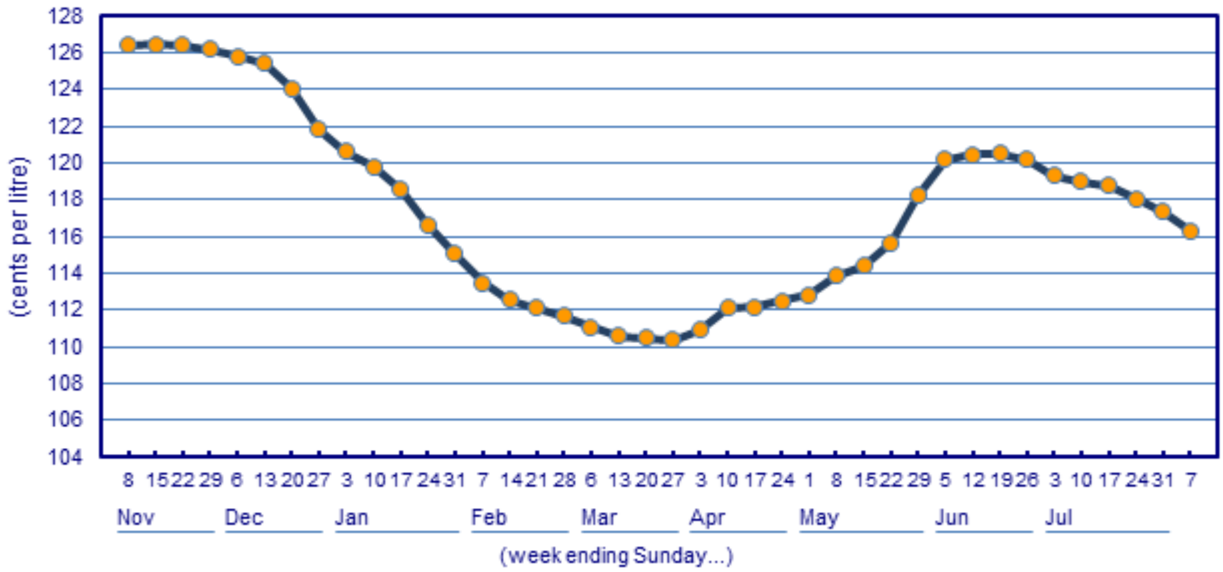
[27] Earth Systems, 2012, pp. 39-41

Diesel Generation

The price of diesel fuel is a critical input in the comparative analysis of scenarios. A price of $1.22/litre has been assumed for diesel fuel delivered to a remote site in South Australia for power generation purposes. This figure was derived in 2013 by consultants IT Power Australia looking at a project in Cooper Pedy[28] and they have clearly shown their working assumptions.

In preparing its analysis IT Power leant heavily on the historical diesel price graph from the Australian Institute for Petroleum[29], and at the time of their report, the retail diesel price was $1.54/litre. They deducted about 30c from the retail price to take into account the Business Fuel Tax Credit, because "electricity generation by commercial generator plant, stationary generator or a portable generator" is an eligible activity to do so.[30] Note that IT Power didn't include the whole credit as they recognised that prices in Cooper Pedy are probably higher than the SA regional average. This is probably true for Kangaroo Island as well. In addition, IT Power also modelled a carbon price and its impact on diesel costs, which is no longer relevant.

Figure 15: Retail diesel fuel price for the 40 Weeks to 7 August 2016



Today, the oil price is lower than when IT Power undertook its analysis, as can be seen in Figure 15 this leads to a lower retail diesel price. Replicating the process of taking the SA regional historical diesel price from the Australian Institute of Petroleum and then deducting a portion of the tax credit (the total tax credit currently is $0.396/litre), would likely result in a value of less than $1/Litre. Therefore, a fixed price of $1.22/litre is conservative, taking into account price trends and tax treatments.

[28] IT Power, 2013, *Data Collection of Diesel Generators in South Australia*, report to Renewables SA, pp. 52-54

[29] http://www.aip.com.au/pricing/retail/diesel/charts/south_australian_regional_average_charts.htm

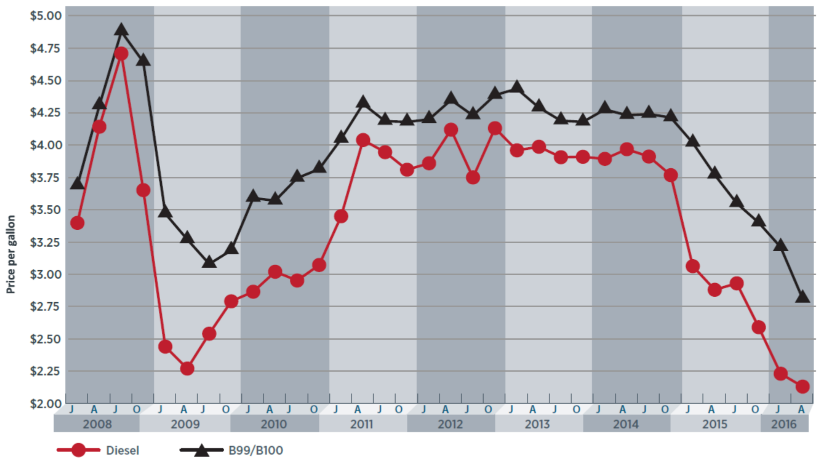
[30] https://www.ato.gov.au/Business/Fuel-schemes/Fuel-tax-credits---business/

Biodiesel Generation

Biodiesel is diesel fuel that has been sourced from renewable resources, for example animal or plant oil. As set out by Jacobs while examining the state bioenergy road map, biodiesel can be used as a substitute for diesel for stationary and transport energy requirements.[31]

For this project we have modelled biodiesel being used as a direct substitute for petroleum-based diesel. It has been used in such a manner in other locations, as can be seen in the King Island Renewable Integration Project.[32] Note that such generation is currently more expensive than conventional diesel, but would allow for diesel generators to be used while maintaining a 100% renewable energy supply. Figure 16 shows the price in the USA of biodiesel (B99/B100) and conventional diesel in US$/gallon. As biodiesel has a lower energy content, it also often requires extra volume to supply the same energy. The US Department of Energy estimates that on average, pure biodiesel is in the order of US$0.25/litre more expensive than diesel equivalent[33], a difference of about 20%. Biodiesel is similarly available from wholesale providers in Australia and we have assumed the cost is 20% higher than conventional diesel.

Figure 16: USA price of biodiesel (B99/B100) and conventional diesel in USD/gallon



Given that the facilities that create biodiesel generally develop millions of litres per annum, it is unlikely that the development of a biodiesel refining industry on Kangaroo Island would eventuate. We note that whilst Kangaroo Island has an appropriate climate and soil for the growth of canola, linseed, mustard and sunflower[34], there is little likelihood or appeal for these crops to be grown for fuel rather than premium food. Consequently, any biodiesel used would need to be imported to the island, similarly to conventional diesel.

An alternative to biodiesel is the production of synthetic diesel from woody biomass-derived oils and gases. Given the large areas of plantation timber on the island, the opportunity to use this resource for generation of electrical energy is real. Most biomass generators now rely on high temperature gasification processes to generate steam that is then used to drive turbines to generate electricity. This process does have the ability to be adapted to utilise the gases to produce a syn-gas or a pyrolysis oil which can then be converted to fully synthetic fuels. These fuels are straight drop-in replacements for conventional fuels and require no engine or fuel system

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[31] Jacobs 2015 *A Bio-energy Roadmap for South Australia*, pp. 29-32

[32] http://www.kingislandrenewableenergy.com.au/project-information/biodiesel-trial

[33] US Department of Energy 2016 *Clean Cities Alternative Fuel Price Report*, p. 24

[34] Earth Systems 2012 *Bioenergy Resource Analysis and Technology: Feasibility for Kangaroo Island*, p. 20

modification and are therefore more attractive that biodiesel alternatives. The production of motor and generation fuel on the island from the eucalypt biomass would be extremely attractive and would add significant value to the island's environmental credentials.

There are now small-scale commercial plants available that could potentially produce the six million litres of diesel fuel used on the island annually for the ferries, trucks, farm equipment, vehicles and generation needs. This is worthy of consideration, but because this technology is at an early stages of commercial development it has not been included in cost estimates for this study.

Marine Power

We note that the area around Backstairs Passage could be utilised to deliver ocean current power. The area has been examined for this purpose, with measurements indicating that tidal flows of up to 2.5 m/s can be expected in autumn and spring, high enough for tidal power to be potentially viable as an energy source.[35]

Due to its predictable nature, tidal power may be especially useful as a method of providing predictable power in a way that complements other renewable sources and minimises the size of batteries or the amount of fuel-based generation required on the island. However, considering the tight timeframes of installation before a solution is required for the cable, we have restricted ourselves to solutions based on more developed and commercially proven technologies. In addition, providing cost estimates on technologies without a record of historical rollout in Australia is difficult.

3.2 WHOLESALE ENERGY PRICE

Kangaroo Island is currently part of the South Australian NEM region. All electricity supplied over the existing cable is supplied by mainland generators. Therefore, Kangaroo Island consumers, through their chosen retailers, pay the wholesale price for generated electricity.

If the cable is not replaced, and the island is no longer electrically connected with the South Australian mainland, then the local community will not have to pay the mainland wholesale price for electricity. Even though the process of installing on-island embedded power would remove the need for network expenditure, it would also remove the need, and ability, for consumers to purchase electricity from the wholesale market.

Instead, the costs for an embedded energy solution would replace the cost of procuring energy from the South Australian wholesale market. In Section 5.5 we provide a possible model that would enable wholesale costs to be included in the electricity payments made by Kangaroo Island consumers.

We have assumed a wholesale energy price of $67.1/MWh as described in Section 2.3 and Appendix A3. This would be avoided by embedded energy use on the island. Note, however, that this is likely to be a conservative estimate as the average price in South Australia has been above this level since the closure of the Leigh Creek Power Station.

[35] Bachmann, R. *Tidal current energy in Backstairs Passage*. Honours Thesis, University of South Australia, p 98.

3.3 NETWORK COSTS

Network businesses are regulated monopolies that provide the connection between consumers and generators. There are two types of network businesses:

- transmission companies that are responsible for the construction and operation of high voltage transmission lines (in South Australia this is ElectraNet)
- distribution companies that are responsible for the construction and operation of low voltage distribution services (in South Australia this is SAPN).

All of the network infrastructure on the island and on Cape Jervis, including the submarine cable, is part of the distribution system operated by SAPN.

Costs for maintaining these networks are paid by consumers via their retailers, and the tariff structure used to pay the network businesses is identical throughout South Australia. This tariff is split between Transmission Use of Service (TUoS) and Distribution Use of Service (DUoS). This is the concept of “postage stamp” pricing which means that customers in the network are charged the same tariffs, regardless of their location. The cost to the network of supplying an individual customer in a rural area is often substantially higher than the cost of supplying an urban customer. However, a customer on Kangaroo Island sees the same network tariff as a customer in Adelaide.

Reflecting these cross subsidies, this study assumes *no change* to total network charges between scenarios. As discussed briefly in Section 2.3, even if and when the existing undersea cable fails, and Kangaroo Island is no longer physically connected to the transmission network, it is assumed that Kangaroo Island consumers would continue to pay the same *unit price for total* network charges.

The alternative of developing new cost-reflective tariffs without transmission pricing would be complicated and arguably inequitable, especially if the tariff attempted to recover the full costs of meeting distribution requirements on the island. We have therefore assumed that customers on Kangaroo Island will pay tariffs that are equivalent to the sum of their existing DUoS and TUoS contributions. Usage and annual supply rates are estimated from the presently applicable network tariffs published by SAPN.[36] However, the *volume* of network charges paid by Kangaroo Island consumers would be reduced in the local supply scenarios, due to reduced net consumption because of demand management and increased behind-the-meter solar on the island.

We note it may be possible for some embedded generators to access payments for “avoided TUoS” as their presence lowers the costs on the transmission network. However, this has not been included in the modelling for any of the scenarios, as it is unclear if avoided TUoS would be available to generators that are no longer physically connect to the transmission grid. Testing this question would be a useful task for future work in this space.

[36] SAPN 2015 Network Tariffs from 1st July 2015

3.4 RENEWABLE ENERGY CERTIFICATES

The Renewable Energy Target (RET)

To encourage the roll-out of renewable energy installations, the federal government has introduced a renewable energy target of 33,000 GWh per year of renewable energy generation by 2020. To facilitate the operation of this target, the government requires retailers and generators to surrender Renewable Energy Certificates (RECs). This policy is planned to remain in effect until 2030.

Renewable Energy Certificates impact on our analysis in a variety of ways. Firstly, any renewable generation on the island would generate certificates. There are two types of certificates that can be created: Small Scale Technology Certificates (STCs) and Large Scale Generation Certificates (LGCs).

A renewable generator may be eligible to create STCs if it is:

- a solar panel system that has a capacity of no more than 100 kW, and a total annual electricity output less than 250 MWh
- a wind system that has a capacity of no more than 10 kW, and a total annual electricity output of less than 25 MWh
- a hydro system that has a capacity of no more than 6.4 kW, and a total annual electricity output of less than 25 MWh.

Any renewable energy systems larger than this level may be eligible to create LGCs.

Modelling the RET

We assume for our analysis that most of the renewable generation deployed to meet a 100% renewable target will qualify for LGCs. Certainly, any wind systems deployed will be above the LGC threshold. In addition, biomass or biodiesel will create LGC certificates.

We observe that distributed solar installations may be eligible for STCs rather than LGCs. However, we consider the number of such systems will be small, relative to the roll-out of wind, biomass and centralised solar. For ease of analysis, we have assumed that all renewable energy will generate LGCs.

Figure 17 shows the cost of the LGCs over the last year. We have assumed a REC price of $57.0/MWh as described in Section 2.3 and Appendix A3. We have also assumed that the REC will be in place to 2030, which is the legislated end date of the target. We observe that it is likely that the government of the time will introduce a policy to encourage renewable generation, however, this is hard to predict what this policy will be. Beyond 2030 we have assumed that Australia will participate in an international carbon market and we have derived a price estimate of $3.61/MWh from the European forward carbon price of 4.94 Euro/tCO_2. This has little impact on the cost results.

We also note that consumers on Kangaroo Island would be liable to surrender some RECs to cover their own consumption. We have made an estimate of this level of RECs and included it in the modelling. In Section 2.3 it is shown as the “RET obligation”.

Renewable energy generators produce an LGC for each MWh exported. In situations where renewable generators are not able to sell their output when there is not enough available load, these generators are unable to claim RECs. In Figure 9 and Table 7 we have referred to this situation as “Curtailed RECs”. We note under the modelling, using renewable energy as a non-network solution requires the total system to be oversized relative to average demand, in order to provide the confidence that peak demand can be met. This means that the level of curtailed RECs can be high when a submarine cable becomes unavailable for export of surplus generation.

Figure 17: LGC Price over the last year[37]

Implications for 100% Renewable Energy

One issue when considering the value of RECs is that they have inherent value for messaging. Generally, statements on the usage of renewable power are linked to final ownership of RECs and their surrendering to the Clean Energy Regulator.

For example, under the GreenPower scheme, retailers purchase energy from the NEM along with a number of RECs to cover obligations to their customers. If it has purchased enough RECs, a retailer does not need to own or operate renewable generation to sell renewable energy-based retail products. If Kangaroo Island generates 100% renewable energy (and makes this claim) while selling the generated RECs to a mainland retailer, then it could conceivably be argued that this generation is being double counted.

Some programs, such as the ACT Renewable Energy Procurement Auction, require any RECs to be surrendered, to ensure that double counting does not occur.

If Kangaroo Island chooses to sell the produced RECs from local generation, it may not be able to claim 100% renewable energy status. Therefore, while we have included RECs, to be able claim 100% renewable status may require that the RECS be retained by the island. The cost of this option is referred to in Figure 9 and Table 7 as "Retired RECs".

[37] http://reneweconomy.com.au/2016/renewable-energy-certificate-prices-hit-record-highs-as-market-prices-in-failure-45170

3.5 PEAK DEMAND

Whichever mix of supply is used (involving a network or non-network solution), it must be able to demonstrate an ability to meet peak demand in current and future scenarios. SAPN have provided the forecast peak demand on Kangaroo Island over the next 25 years as shown in Table 10. Power supply options were modelled in 2017 and 2041 by scaling the annual load profile, also provided by SAPN, so that the actual peak demand equalled the 10% PoE forecast peak demand for the financial years 2016-17 and 2040-41.

Table 10: Peak load forecasts for Kangaroo Island

Year	10% PoE Forecast (MVA)	10% PoE Forecast (MW)	Year	10% PoE Forecast (MVA)	10% PoE Forecast (MW)
2016/17	8.0	7.8	**2029/30**	10.4	10.1
2017/18	8.1	7.9	**2030/31**	10.6	10.3
2018/19	8.3	8.0	**2031/32**	10.9	10.6
2019/20	8.4	8.2	**2032/33**	11.1	10.8
2020/21	8.6	8.3	**2033/34**	11.4	11.0
2021/22	8.8	8.5	**2034/35**	11.6	11.3
2022/23	9.0	8.7	**2035/36**	11.9	11.6
2023/24	9.2	8.9	**2036/37**	12.2	11.8
2024/25	9.4	9.1	**2037/38**	12.4	12.1
2025/26	9.6	9.3	**2038/39**	12.7	12.4
2026/27	9.8	9.5	**2039/40**	13.0	12.7
2027/28	10.0	9.7	**2040/41**	13.4	13.0
2028/29	10.2	9.9			

If a non-network solution is implemented, the total generation capacity on the island would need to be large enough to meet the peak demand as outlined above.

Under these circumstances, there would be periods where renewable resources, such as wind or solar, were present, but there would not be any load to meet this excess capacity. As a consequence, the generators would be constrained and unable to generate; that is, energy would be “curtailed”. Curtailment due to lack of load would impact the profitability of generators on the island, as they would not be able to earn revenue for their generation at their full capability. As discussed in Section 0, this would impact the ability of these generators to create RECs.

4 ENSURING RELIABLE SUPPLY

SAPN provides 99.97% network availability, on average, to its customers.[38] This equates to a total duration of power interruptions of 150 minutes per year. As with any distribution business, maintaining and improving reliability is a key concern. For customers, reliability represents the certainty that they will have access to supply when wanted. Having confidence in maintaining reliable supply of electricity to customers on the island will be a central part of SAPN's decision-making process in relation to the solution for Kangaroo Island.

This section sets out three areas that need to be considered to ensure reliability if a non-network option is chosen as an alternative to replacement of the submarine cable. They all address the concern, when using a renewable energy-based system, that the variable nature of supply can potentially lead to not being able to maintain supply at all times. Variable supply can be matched to variable demand through:

- demand management
- controllable generation
- energy storage
- dispatch and coordination.

4.1 DEMAND MANAGEMENT

Demand management involves deliberate action by a supplier to reduce demand for a commodity rather than reducing supply to meet demand. In terms of energy supply, it includes actions by consumers to reduce their demand when such actions provide the most value.

There are two specific times when demand management activities have value for the network. The first is where, in the absence of demand management, the load would be approaching the peak. If there were actions to reduce peak demand at these times, they would reduce the amount of generation necessary. This would reduce both the investment in generating capacity that would otherwise be necessary, and the losses associated with renewable energy curtailment at other times.

The second situation in which demand management would have value is when supply from renewables is minimal, specifically times when there is minimal wind and sunlight. In these circumstances, confidence in demand management would allow for lower expenditure on contingency support.

Reliable demand management for Kangaroo Island would identify loads that could be controlled up or down, or switched off, with little or no impact on the customer. Industrial loads that are not time critical, such as pumping, sometimes fall into this category. But the stand-out opportunity is most likely approximately 2 MW of residential hot water systems presently operating on timers. It seems reasonable that these could be brought under effective control for real-time demand management. According to SAPN, the peak demand on Kangaroo Island occurs "on a few hot/cold days a year". Load is in excess of 95% of the peak for approximately five hours per annum, and the average load of 3 MW is approximately 50% of the peak.[39] These figures suggest that there is additional demand management potential that should be investigated.

[38] http://www.sapowernetworks.com.au/centric/industry/our_network/reliability_improvements.jsp

[39] SAPN 2016 *Non-Network Options Report: Kangaroo Island Submarine Cable*, p. 12

In addition to active demand management, energy efficiency measures resulting from concerted efforts to improve the productivity of energy use would make a substantial contribution to ensuring energy independence on the island. Every kWh saved is a kWh of generation not needed. The Council of Australian Governments (COAG) Energy Council has committed to a National Energy Productivity Plan that aims to achieve a 40% improvement in the effectiveness of energy use by 2040.

The expectations of demand on Kangaroo Island, shown in Table 10, do not assume any specific energy efficiency programs in the state. However, a focused energy efficiency program looking into residential and business energy use on the island will provide a reduction in generation requirements for the island if the submarine cable is not replaced.

In all the local generation scenarios, apart from Scenario 3A, we have assumed that there can be a demand management impact of 10% achieved quickly by 2017, followed by incremental improvements to an impact of 20% by 2041. These levels of demand reduction are regularly achieved by demand management programs[40] at an average cost of $70/MWh. This cost is similar to our assumed wholesale electricity price and is likely to be an overestimate for a demand management program that targets “low-hanging fruit” such as the residential hot-water opportunity. However, detailed analysis would be required to obtain a firmer costing.

There is also the question of who would pay for a demand management program. It could be either the network operator or the owners of new local power generators, both of whom are beneficiaries of the program, and both of whom might recoup the cost from energy bills. This is a cost assignment problem alongside other issues discussed in Section 5.

4.2 CONTROLLABLE GENERATION

In isolation, variable output renewable energy options such as wind and solar generation are unable to guarantee power availability at all times, particularly when they are not geographically dispersed. As a consequence, it is necessary to provide additional, controllable generation to supply the amount of load that cannot be met at any given time by variable renewable generation. This is often referred to as the “residual load”. Renewable generation curtailment, when it is in excess compared to the load, represents wasted investment in renewable generation capacity and should be reduced if possible.

Controllable generation can be provided by:

- diesel generation
- biodiesel generation
- biomass generation
- real-time load management
- generation curtailment
- energy storage (e.g. batteries).

Some of these options are more desirable than others. Diesel generation, for example, is effective but reduces the fraction of renewable energy supply. Biomass is excellent when available but is not always amenable to rapid changes in output to balance variability of wind, solar, and load. Load management is cost effective provided that it can be implemented without adversely affecting the participating households and businesses. Energy storage is the ideal solution from the point of view of responsive control, but fault current levels need to be considered when using energy storage over rotating machines such as diesel or biomass generators. Energy storage is the most expensive option for energy provision, although it can be cost effective from the perspective of power capacity. Due to the rapidly evolving energy storage market, this option is given more detailed consideration below.

[40] US Energy Information Administration (EIA) 2011 The Annual Energy Review

4.3 ENERGY STORAGE

Energy storage can be used to maintain supply where variable energy supply is temporarily not available. Highly responsive types of energy storage, including many types of batteries, can also be used to help balance supply and demand in real time, a balance which is challenging to achieve for an island power supply. In our modelling we have assumed that responsive batteries will be used for energy storage, and we have used representative costs for lithium ion batteries because these are readily available at scale from a variety of vendors. It is important to distinguish between batteries used for "energy shifting" which may require several hours of storage duration according to the variable supply, and batteries used only for "balancing" to reduce the ramping rates of fuel-based generators (diesel or biomass). Representative costs and storage durations (power-to-energy ratios) of both types of battery are shown in Table 11. These are installed costs which include the cost of inverters and balance of plant for typical lithium ion battery systems.

The residential market segment can be considered for batteries on Kangaroo Island. This is now a competitive market in Australia, with strong downwards price pressure. Many residential customers are highly motivated to obtain energy storage, particularly if they already have rooftop PV systems, and this suggests that a subsidy scheme to encourage residents to purchase batteries could be attractive both for customers and as a means of obtaining low-cost storage capacity for energy shifting or balancing purposes. A typical residential battery is one of the three types represented in Table 11, which clearly shows that the type of battery has a profound effect on the price per capacity, whether this is shown per kWh or per kW. The residential storage opportunity has not been modelled for this study, partly because there are many variables related to the business model that need to be determined. Nevertheless the potential for obtaining low-cost energy storage services from residential batteries is a present reality and opportunity.

We note that there are other storage technologies that are potentially available, but for simplicity, given the limited time available to complete this study, we have confined our analysis to one commonplace technology. This should not discourage proponents of other technologies from developing an investment case in partnership with a system integrator.

Table 11: Cost and storage duration assumptions for lithium ion batteries

Type of Battery	Price [$/kWh]	Storage duration	Price [$/kW]
Energy shifting	1,700	3 hours	5,100
Balancing	2,500	30 minutes	1,250
Residential	1,250	2.4 hours	3,000

4.4 DISPATCH AND COORDINATION

Currently, as Kangaroo Island is connected to the NEM, generation dispatch and payments is the responsibility of the Australian Energy Market Operator (AEMO) as part of the general South Australia region of the NEM. This includes not just energy supply, but also ancillary services such as frequency control and system restart capabilities. In the event of the cable being disconnected, Kangaroo Island would no longer receive these services through the NEM framework. Responsibility would need to be allocated to a different authority.

This body would need to be in charge of ensuring that enough supply was available and was dispatched. In making these decisions the operator would, on a full-time basis, have to take into account:

- the fuel availability and operational status of generators on the island
- load forecasts
- network capacity
- security and reliability of the power system.

We have not modelled a cost for the operation of this role, as it would be built into the operation of the network. The costs for grid management will need to be assessed in future studies.

A renewable power-based supply system requires a significantly different power dispatch and coordination compared to a conventional power system. In many power markets around the world renewables take an increasing market share in the electricity supply, and the integration of large-scale renewable energy is becoming less problematic as more and more experience has been gained with power systems that have large shares of flexible power generation.

To maximise the use of solar and wind generation, these sources can be given priority dispatch in the power grid, followed by storage technologies that either store surplus generation or provide additional generation until the battery capacity is reached. Once there is no solar, wind and battery generation available to meet the demand, fuel-based generation will be used to supply the remaining demand. The generation "cascade" adopted for this study is shown in Table 14.

Solar and wind generation can be forecast up to 72 hours ahead in 15-minute steps, using technology that is well established in power grids in Spain, Germany, Denmark, and Australia that have high wind shares.[41] This permits well-regulated dispatch of fuel-based generation, and with effective planning the share of curtailed solar and wind generation can be kept to a minimum to keep capacity factors high and generation costs low.

[41] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

4.5 POWER GRID CONTROL ISSUES

It is essential that a power grid in island operation mode can maintain voltage and frequency stability in response to demand fluctuations as well as weather-induced variations in renewable generation. Furthermore, power quality must be kept within certain standards, and there should be strategies to ensure stable operation during network disturbances such as the failure of a significant generator or the removal of a large load. During the time that the existing cable remains operational, Kangaroo Island has an opportunity to build local generation capacity and develop and test a local grid control system.

If community engagement is at a high level, the island might be disconnected from the mainland grid for short periods of time to practise operating in "islanded" mode. At the conclusion of each such period, the island grid would be switched back to grid-connected mode, making sure that the voltage, frequency, and phase of the Kangaroo Island grid is synchronised with that of the mainland grid at the point of common coupling. This would be another responsibility of the local grid control system.

When the Kangaroo Island grid is connected to the mainland grid, its frequency will be dictated by the mainland grid, and the voltage at the point of common coupling will be controlled by the central grid. It would be unusual to require any active voltage control within the Kangaroo Island grid.

When the Kangaroo Island grid is operating in islanded mode, voltage and frequency must be maintained within the correct tolerance limits to ensure the correct operation of grid equipment and the safety of customers and operators. The largest generator is typically selected to be responsible for frequency control. If it is solar PV, the droop control method[42] is commonly implemented in the control mechanisms of associated batteries. This process has the advantage that expensive communication systems and extra cabling for a control bus can be avoided. This approach presents several advantages including low cost, simple expansion of the system, increased redundancy and simplified supervisory control.[43] If the largest generator is a wind turbine, power conversion systems are available that are capable of acting as the frequency reference for the local grid. If the largest generator is a diesel power station or a biomass generator, these are synchronous rotating machines that are commonly used to maintain frequency control in interconnected power grids.

[42] D. Kanellos, A. I. Tsouchnikas and N. D. Hatziargyriou 2005 Micro-Grid Simulation during Grid-Connected and Islanded Modes of Operation," in *International Conference on Power Systems Transients*, Montreal

[43] Martensen, Kuwahata, Ackermann, and Teske 2012 E[R] Cluster for a smart energy access, Amsterdam/Delhi

5 INSTITUTIONAL ISSUES

The focus of this study is on the practical and financial feasibility of local renewable generation on Kangaroo Island, as an alternative to building a new electricity supply cable from the mainland. While the detailed institutional arrangements of such a strategy are beyond the scope of this study, the following brief discussion outlines the institutional assumptions underlying the assessment and raises some issues for further consideration.

The following institutional and regulatory issues are considered:

1. access to the National Electricity Market
2. managing the market and price control
3. network management
4. local generation ownership and management
5. retailing electricity
6. the RIT-D process.

5.1 ACCESS TO THE NATIONAL ELECTRICITY MARKET

As Kangaroo Island is currently connected to the main South Australian electricity grid, it is also electrically and administratively part of the National Electricity Market (NEM) and regulated under the NER. This means that:

1. Electricity supply on Kangaroo Island is electrically synchronised with the mainland.
2. Kangaroo Island has access to the competitive generation and retail market.
3. Kangaroo Island is subject to the laws and regulations of the NEM.

If Kangaroo Island were to establish self-sufficiency in electricity supply on the island, this would not automatically change any of these arrangements, so long as the existing cable to the mainland remains operational. Conversely, if the cable were to fail today, Kangaroo Island would lose access to NEM electricity supply and markets, but would remain administratively part of the NEM.

Therefore if Kangaroo Island were to become electrically self-sufficient, ***and*** the existing cable were to fail at some point in the future, it does not automatically follow that Kangaroo Island would be required to cease being administratively part of the NEM. Indeed, the potential for Kangaroo Island to remain part of the NEM despite being physically separated has recently been highlighted by the Western Australian Government's consideration of whether it should also join the South Western Interconnected Market to the NEM[44], as well as Tasmania joining the NEM before the completion of the Basslink submarine cable.

Therefore, for the purposes of this study, it is assumed that in the case of Kangaroo Island becoming electrically self-sufficient and the existing cable failing at some point, then Kangaroo Island would remain administratively within the NEM. This also assumes that normal NEM administrative and regulatory obligations and charges, including the Renewable Energy Target (RET), would still apply on Kangaroo Island.

However, if the cable fails then the cessation of access to the competitive market of the NEM would have significant implications that would need to be addressed, particularly in relation to retailing electricity and price control. These issues are considered briefly below.

[44] http://www.energyaction.com.au/news/latest-news/2015/04/08/wa-electricity-market-review

5.2 MANAGING THE MARKET AND PRICE CONTROL

In order to establish viable and equitable local electricity supply, it is necessary to balance, on the one hand, sufficient secure economic return for the owners of electricity supply (generation and storage) in order to justify initial investment, and on the other hand, sufficient control over market power to ensure that customers are able to access electricity supply at a fair price.

If the electrical connection between Kangaroo Island and the mainland fails, then there would be no effective competition in the provision of electricity supply services on the island. As the size of the market on Kangaroo Island is too small to support effective competition in generation and retail, this raises the question of how the monopoly position of the electricity suppliers on the island would be managed in a way that ensures cost-effective supply of the electricity.

There are a number of ways in which this can be achieved. One way is through direct price regulation by, for example, the Australian Electricity Regulator (AER) or the Essential Services Commission of South Australia (ESCoSA). However, for a small community of just 4,500 people such as Kangaroo Island, the process of direct price regulation may be unnecessarily cumbersome and costly. So consideration should be given to other more localised and flexible approaches.

The key components of electricity costs that need to be considered in setting fair prices are:

- network
- generation
- regulatory and market administration
- retailing and billing.

Each of these elements is briefly discussed below.

5.3 DISTRIBUTION NETWORK MANAGEMENT

Whether Kangaroo Island is electrically connected to the mainland or independently served by local generation, it still requires an electricity distribution network system to reticulate power to the energy users on the island. Consequently, Kangaroo Island requires a distribution network service provider (DNSP) to manage the network. The network is currently owned and managed by South Australia Power Networks (SAPN). As in other rural and regional areas of Australia where a relatively large distribution system serves a relatively small and dispersed population, it is likely that the cost of service provision on the island significantly exceeds the network charge revenue collected from the island.

In principle, it is possible that a different owner and service provider for the Kangaroo Island electricity distribution system could be established. For example, these services could also be contracted out by Kangaroo Island Council or the South Australian Government to be provided by another party, as is the case for some remote area power supplies in the north of South Australia.

However, given that well-established and efficient network service provision is already in place via SAPN, there appears no strong argument to change the current arrangements. Therefore, this assessment assumes that the network service provider role will continue to be performed by SAPN throughout the next 25 years, regardless of whether the electricity connection to the mainland is maintained or not.

Reflecting the desire on the part of the Kangaroo Island community for high-quality electricity services, and the prevalence of Single Line Earth Return (SWER) lines in parts of the network away from the main towns, SAPN has a regular budget for maintaining and upgrading the distribution network on the island, and we assume that this level of expenditure would be similar for a Local Hybrid Solution to power supply. In principle, by strategic placement of local generation resources and demand management, peak loads on the distribution network could be managed so as to reduce the need for future network augmentation.

5.4 LOCAL GENERATION OWNERSHIP AND MANAGEMENT

For local generation and storage to be established on Kangaroo Island, some party needs to invest in, own and manage it. The total present value of investment for local generation and storage is likely to exceed $55 million (as per Scenario 3A). There are a range of possible parties who could in principle take on these roles, including:

- Kangaroo Island Council
- community ownership
- commercial investors
- individual consumer ownership
- State or Federal government ownership
- SAPN.

The following is a discussion of some of the pros and cons of each of these options. Different ownership structures may be appropriate for different supply technologies.

Provided the business case is attractive, the **Kangaroo Island Council** may be interested in having some ownership and management stake in the local generation, as is the case on Lord Howe Island, where the Lord Howe Island Board owns and operates the power station. However, the Kangaroo Island Council may not have either the relevant expertise to manage the plant technically, the financial capacity to cover the full investment cost, or the willingness to carry the full financial risk.

Members of the local Kangaroo Island community may also be interested in acquiring an ownership and management stake in some local generation, either through a cooperative or a company structure with diverse ownership. There a numerous examples of community ownership of wind and solar generators in Australia and overseas. Again, this will depend on an attractive business case and how secure the revenue stream is perceived to be.

Commercial investors, particularly those with existing commercial interests on Kangaroo Island, may be very interested in acquiring an ownership and management stake in local generation, provided the business case is attractive. This may be particularly so for larger and more complex plant such as a diesel, biodiesel or biomass generator. Such investors may seek to increase community acceptance of such plants by sharing ownership and management with local community or local government stakeholders.

Individual consumer ownership will likely be most appropriate for small-scale plant such as household and small enterprise rooftop solar and battery systems. These are likely to be most valuable for dispersed consumers on the Single Wire Earth Return (SWER) network away from the main townships.

The state and federal governments are unlikely to wish to take a large ownership stake in local generation, except to the extent that it helped promote existing policy objectives. In this context, government agencies such as the Clean Energy Finance Corporation or ARENA may be interested in offering equity to facilitate more rapid investment in local generation.

In principle, SAPN may be interested in investing in some key supply infrastructure such as diesel stand-by generation or large-scale batteries that have strong grid support capacity. There are precedents in Australia for network businesses doing this.[45] However, if it were to do this, SAPN would need to be satisfied that this represents an efficient investment and is consistent with current ring-fencing guidelines regarding ownership of non-network assets.

In summary, it seems likely that the optimum ownership and management structure of local generation is some mix of most, if not all, of the above options. For the purposes of the analysis we have not assumed any particular ownership mix, but simply that an appropriate mix can be found.

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[45] For example, the battery-diesel hybrid network support system demonstrated by Ausnet Services and described in http://www.seiavic.org.au/uploads/2/7/8/3/27837477/seia_vic__19_feb_2016_ausnet.pdf

5.5 RETAILING ELECTRICITY

In the absence of a cable connection to the mainland, there would not be effective retail competition for electricity supply to Kangaroo Island. However, efficient and affordable pricing can still be facilitated. Network charges can be pegged to mainland rates as discussed above. Normal NEM administrative and market charges could still be applied. Generation charges could be set through long-term power purchase agreements. However, to facilitate collection of these charges and to provide a counterparty for power purchase agreements, there is still a requirement for a retailing entity to provide wholesale purchasing and billing functions. In principle, there could be more than one retailer, but given the small population of Kangaroo Island, a single retail entity is likely to be more efficient.

The most obvious possible candidates to undertake these retailing functions are:

- an existing electricity retailer
- Kangaroo Island Council
- an integrated community energy company
- SAPN.

The following is a brief discussion of some of the pros and cons of each of these options.

An **existing licensed electricity retailer** (such as AGL, Origin, Enova, etc.) could be engaged to enter into long-term power purchase agreements with the generators on the island and to provide retailing services over a long period, such as 20 years. However, there are major drawbacks with this approach and it is unclear how this could work in practice. Firstly, it would require some entity to select the retailer on behalf of the whole island community. Neither Kangaroo Island Council nor the South Australian Government is likely to be willing or able to do this, and the local community as a whole is unlikely to support such an approach. Secondly, once engaged in such a long-term contract, the retailer would have great market power, which would likely require some long-term price regulation system, as discussed above.

Alternatively, an existing licensed electricity retailer could be engaged to provide billing services according to fixed tariffs over a shorter period, say three to five years without entering into long-term power purchase agreements with the generators. This would allow the retailer to provide crucial billing services for customers but they would be subject to regular market discipline through tendering without undue market power. However, this would require another entity to enter into long-term power purchase agreements with the local generators.

In this context, the **Kangaroo Island Council** could be the party to enter into long-term power purchase agreements with the local generators, on behalf of the island community. This would be a significant undertaking as it would involve a commitment to purchase tens of millions of dollars' worth of wholesale electricity over a period of say, fifteen to twenty five years. On the other hand, in return for carrying this risk there could be a significant financial return to the Council via the margin between wholesale and retail electricity prices.

A third option would be for the Council to share the risk and return associated with the long-term power purchase agreement with the community through a **community energy company** as discussed under generation ownership and management above. If ownership of the energy supply was sufficiently broadly owned by the community (including the council), this could provide a natural brake on monopoly power because the owners of the generation would be directly responsible to the same community that is purchasing the power.

In principle, **SAPN** could also enter into long-term power purchase agreements with the local generators, but given ring-fencing requirements this is unlikely. On the other hand, in order to facilitate the establishment of local generators as an alternative to the new cable option, it would likely be essential for SAPN to enter into long-term "network support contracts" with local generators. Such contracts would likely be essential to ensure that SAPN could be confident that local supply will be available when required to support the local grid, and these contracts would likely be worth tens of millions of dollars. The existence of such contracts would offset the scale and risk associated with the long-term power purchase contracts.

5.6 THE RIT-D PROCESS

In making its decision on the cable, the SAPN will be following the process in the AER guideline for investments, which follows the requirements of the National Electricity Rules.

The RIT-D process is designed to "assist market participants in making efficient investment decisions and enable non-network providers to put forward non-network options as credible alternatives to network investment."[46]

However, the current RIT-D process does not ensure a balanced consideration of network and non-network options development of the process. Under the RIT-D process, a network business is required to identify an issue to be resolved and publicly consult on potential solutions. Such consultations generally involve public comparisons of cost-benefit analyses of a variety of different network and non-network solutions. Using the information, the business chooses the solution with either the highest net benefit, or the lowest net cost, if the solution is required to maintain reliability.

In preparing the costings and plans for the different network solutions, a network business is able to call upon its own experience and knowledge of the relevant technical matters. In addition, planning studies and investigations undertaken as part of the network's regulated activities can be used as inputs into the assessment of the RIT-D.

On the other hand, for non-network opportunities the RIT-D largely relies on external input, mostly from commercial businesses. In simple cases this can be easily developed, for example where a single customer with a large load in an area can be invited to supply cost estimates for demand management in response to peak demand times.

However, for the development of more complex non-network solutions which involve the interaction of demand management and distributed generation, it may be difficult to develop comprehensive costings. For such solutions to be considered, information supplied to the RIT-D needs to include:

- a high level system design
- rigorous estimates of costs
- evidence that the all requirements of the networks, including reliability, can be met.

For a commercial business, research and preparation of such information can represent a substantial investment of resources. However, for the network business, this is not an application for a tender, but rather an input into a regulated assessment process.

At the completion of the RIT-D, the business will choose the solution that resolves the identified need, with the information provided at lowest net cost. If this is a non-network solution, the network will likely call for tenders for provision of the service. Certainly, any proponent that contributed to the RIT-D will have a slight advantage in preparing a tender response, but that doesn't mean they are in a position to guarantee they will be the chosen provider.

This may mean that a business, despite spending resources on an RIT-D submission, will not be successful in a tender to provide services they specified, and one of their competitors will be selected to provide the non-network solution. This creates a free-rider problem whereby the optimal strategy for a non-network proponent may be not to provide information to the RIT-Ds, but instead to wait for calls for tenders where non-network solutions are already chosen.

This may result in network businesses making decisions that are not fully informed, as external commercial enterprises may have an incentive not to provide all the relevant information.

[46] AEMC 2012 Rule determination: *Distribution Network Planning and Expansion Framework*, p. i

APPENDICES

A1. List of Interested Parties

A2. Precedents for Renewable Energy Islands

A3. Modelling Inputs

A4. Detailed Modelling Results

APPENDIX A1: LIST OF INTERESTED PARTIES

The following table lists companies with relevant expertise that have been in contact with the report authors in relation to this study. Only those parties who have given explicit permission to include their contact details have been listed.

Company	**Contact Person**	**Contact Details**	**Company focus** (self-described)
Atlantis Resources	Andrew Dagley Head of Asia Pacific	+65 6248 4688 andrewdagley@atlantisresourcesltd.com	Atlantis is the world's leading global developer of tidal stream generation equipment and utility scale projects.
EDL	Keith Barker Executive General Manager	(07) 3275 5667 keith.barker@edl.com.au	Energy Developments Pty Limited owns and/or operates a diverse, global portfolio of over 900MW of power generation in two core business areas - Remote Energy and Clean Energy.
Efficient Power Alternatives	Colin Rohde General Manager	(08) 8981 7544 colin@efficientpower.net.au	Efficient Power Alternatives provides 100% renewable energy and efficient solutions of any scale to residential, commercial, industrial and utilities applications as a base load system.
Environmental Energy Australia	John Thomas Managing Director	+61 437 061852 johnthomas@lloydte.onmicrosoft.com	Environmental Energy Australia Pty Ltd was formed by a small group of people, with an interest in power generation and power solutions, principally focused in South Australia. Our company has experience in agribusiness, business innovation, telecommunications, power generation and energy trading. EEA was the major proponent behind the Fleurieu Power Project, a proposed non network solution to the needs of the eastern Fleurieu Peninsula.
Epuron	Andrew Durran, Executive Director	+61 (0)2 8456 7400 A.Durran@epuron.com.au	Epuron is a leading Australian renewable energy company. Epuron has been developing utility-scale wind & solar energy projects in Australia since its formation in 2003.

Flow/Brookfield Energy Australia	Daniel Hilson Executive Manager Energy and Urban Renewal	(02) 8016 1014 dhilson@flowsystems.com.au	Flow designs local embedded networks for new developments and precincts. We harness the latest innovations bringing together water and energy infrastructure and services to reduce costs, underpin sustainability and deliver customers benefits. Flow is an Australian company, 51% owned by Brookfield Infrastructure.
GreenSync	Phil Blythe Managing Director	(03) 9008 5986 phil@greensync.com.au	GreenSync is a high growth Australian technology company that specialises in distributed energy for the global electricity market; embracing the new genre of embedded generation, storage and internet enabled devices.
Hydro Tasmania	Ray Massie Development Manager Hybrid Off-Grid Solutions	(03) 6230 5293 ray.massie@hydro.com.au	As an Owner-Operator of utility grade hybrid off-grid power systems Hydro Tasmania understands the challenges of reducing operating cost while maintaining system stability and can offer world leading proven integration solutions to significantly reduce diesel in remote off-grid power systems.
Kangaroo Island Plantation Timbers Ltd	John Sergeant Managing Director	0412345359 john.sergeant@kipt.com.au	Kangaroo Island Plantation Timber can supply timber for biomass solution.
Optimal Group	Deke Faile Business Development	1300 67 84 76 deke.faile@optimalgroup.com.au	Optimal Group is focused on lowering the cost of power, heating & cooling for commercial, industrial and government clients.
Resonant Solutions	Graham Davies Director	08 8418 3892 graham.davies@reson.com.au	Resonant Solutions provides innovative and practical solutions that improve business performance. Key industries include renewable energy (including solar PV, solar thermal, wind), micro-grids, waste heat recovery, energy efficiency and energy management.

SGK Stanger	Shotaro Tsuyumu Sales Manager, Insulator Business and NAS battery Business	(03) 9401 6215 shotaro@ngkstanger.com.au	SGK Stanger supplies high capacity sodium-sulphur batteries for use in response to large power fluctuations.
SkyFarming	Andrew Woodroffe	(08) 94307371 awoodroffe@skyfarming.com.au	SkyFarming Pty.Ltd. is a small consultancy with experience in the fields of infrastructure project development and financing, renewable energy and wind resource evaluation, structural engineering and project management.
Tesla	Lara Olsen Regional Manager - Business Development	+61 401 660 628 laolsen@tesla.com	Tesla is committed to accelerating the transition to sustainable energy. Tesla has installed more than 50 GWh of stationary storage globally and provides both residential and commercial/utility level storage options. In addition to Powerwalls in homes across Australia, Tesla have numerous grid scale storage projects in Australia and New Zealand.
VSun	Samantha McGahan Business Development Manager	(08) 9228 3333 samantha@vsun.com.au	VSUN offers customers a series of products and services centred around the generation and storage of renewable energy including vanadium redox flow batteries.
Zinfra	Umer Mohammed Business Development Manager – Southern Contracting	0427 730 531 umer.mohammed@zinfragroup.com.au	Zinfra Group is a leading service provider to the utility infrastructure sectors delivering a comprehensive range of engineering, operations, maintenance and construction services. Our services include engineering and design, project management, construction, civil, maintenance and asset operations.

APPENDIX A2: PRECEDENTS FOR RENEWABLE ENERGY ISLANDS

This appendix looks at other islands, both in Australia and internationally, that have made movements towards full or substantial renewable electricity supply. The five other islands that we examine are:

1. King Island in Tasmania (Australia)
2. Samsø in Denmark
3. Pellworm in Germany
4. Tokelau, New Zealand
5. the DeGrussa Mine in Western Australia.

The DeGrussa Mine is not an "island" but exemplifies remote communities with a significant electrical demand that are not connected to the national grid. Such situations occur frequently in Australia. A summary of the main features of each island is shown in Table 12 below.

Table 12: Island power supplies

Island	Popul-ation	Visitors per annum	Area	Current Peak Load	Energy Demand	Existing Renewable Energy Summary
Kangaroo Island	4,500	>500,000 Visitor nights[47]	4,405 km²	8 MW	32 GWh p.a.	1.7 MW solar PV (rooftop)
King Island	1,700	>5,000[48]	1,098 km²	2.5 MW	12 GWh p.a.	2.5 MW wind, 0.4 MW solar PV, 6 MW diesel with biodiesel blending plant, storage via flywheel and batteries, resistors for load balancing[49]
Samsø	4,000	500,000 overnight bookings	114 km²	12 MW	31 GWh p.a.[50]	Wind, solar PV, and biogas power, supported and exporting via submarine cable connection
Pellworm	1,200	>300,000	37 km²	1.5 MW (est.)	7 GWh p.a.[51]	Wind, solar PV, and biogas power, supported and exporting 14 GWh p.a. via submarine cable connection
Tokelau	1,500	-	10 km²	1 MW capacity system	-	100% RE, mainly from solar energy, no connection with larger electricity system
DeGrussa Mine	420	-	-	19 MW	-	10.6 MW solar PV, 6 MW Li-ion battery, 19 MW diesel power station, no connection with larger electricity system

47 http://tourism.sa.gov.au/assets/documents/Kangaroo_Island_-_Copy.pdf
48 http://www.tourismtasmania.com.au/__data/assets/pdf_file/0013/20074/Economic_Impact_Analysis_Tourism_King_Island.pdf
49 http://www.kingislandrenewableenergy.com.au/project-information/overview
50 http://vbn.aau.dk/ws/files/220291121/Sams_report_20151012.pdf
51 http://www.electronics-eetimes.com/news/pellworm-project-blueprint-smart-energy-future

A2.1 KING ISLAND, TASMANIA

King Island is located in the Bass Strait and has a population of just under 2,000 people. It is electrically islanded, and not connected to the mainland or Tasmania.

Historically, electricity was largely supplied from diesel generators on the island. Hydro Tasmania, which is responsible for supply, introduced the King Island Renewable Energy Program (KIREP). The objective of the program is to reduce diesel fuel consumption for power generation by up to 65% on average every year, and to provide the ability to generate 100% of the island's power needs using renewable energy when conditions allow. In late 2015, the island ran for two full days with zero diesel operation.

The KIREP program increased renewable energy generation on the island, leading to a reduction of diesel consumption from 4.5 million litres to around 2.6 million litres per annum since the beginning of the program.

A2.2 SAMSØ, DENMARK

Samsø is an island 15 km off the coast of the Jutland Peninsula, shown in Figure 18, with a population of 4,000. As well as having a population similar to Kangaroo Island, Samsø is also host to a substantial number of tourists, with over 500,000 overnight bookings annually. Some analysis claims that Samsø's 100% renewable energy status has led to increased tourism.

In 1997, the Danish government committed to powering Samsø with 100% renewable energy. This has been a success and Samsø is currently a large net exporter of renewable energy into the Danish grid, with system reliability able to be maintained using the connection to the mainland. The island is predominantly powered by 11 onshore and 10 offshore wind turbines, along with installed distributed solar PV.

The systems installed in Samsø are community owned. Of the 21 turbines, 20 are partially owned by locals who receive a payment for their generation. It is our understanding that the community involvement and ownership of the generation led to increased acceptance of the roll-out in an economically depressed area.

Figure 18: Map of Samsø[52]

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52 http://ecowatch.com/2014/05/01/samso-renewable-energy-island-sustainable-communities/

A2.3 PELLWORM, GERMANY

Pellworm in the North Sea started to install solar and wind systems in the 1990s. In 2012, under the “Smart Region” program, work began on installing a smart grid to better utilise the island’s resources. In 2014, the overall smart grid concept was successfully implemented and the demonstration phase started. During this phase, the optimal interaction of locally produced electricity and local demand is being tested. The aim is to significantly reduce imports from the German mainland.

The island features a Redox-Flow battery to store electrical energy. This technology uses a fluid to charge and discharge. By using a liquid, storage capacity can be extended by external tanks as opposed to other battery technologies that can only increase storage capacity by adding new battery cells.

Over 75% of the local population of 1,500 people support the island’s renewable energy project. Pellworm is an island which is visited by over 300,000 visitors per year. As part of the renewable energy project there is a visitor centre, which increases public knowledge as well as organising trips to wind farms and solar fields.

The German utility and transmission grid operator E.ON operates the local grid and project partners for the publicly funded research project. The following diagram provides an overview of the power supply system.

Figure 19: Pellworm power system

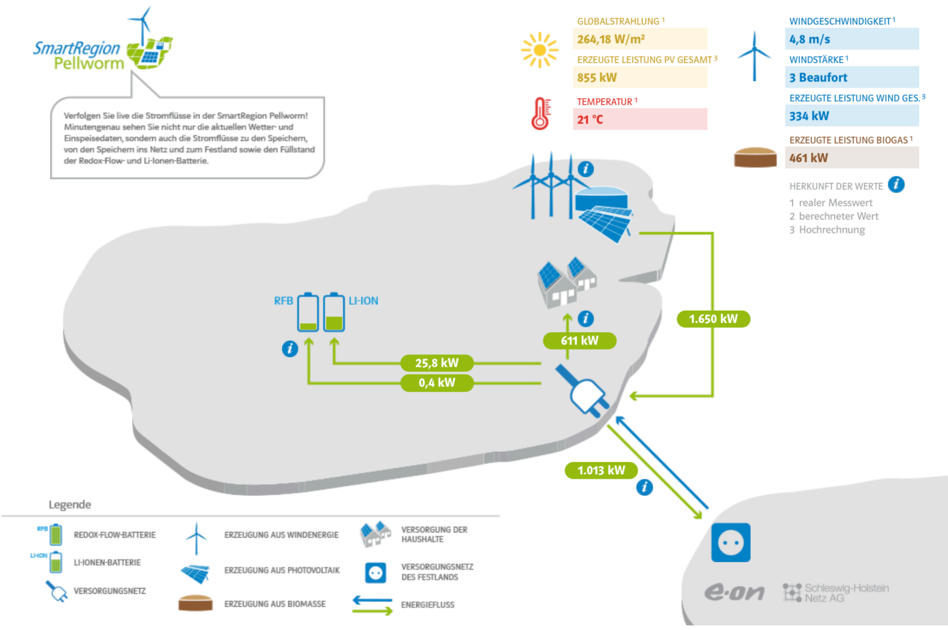
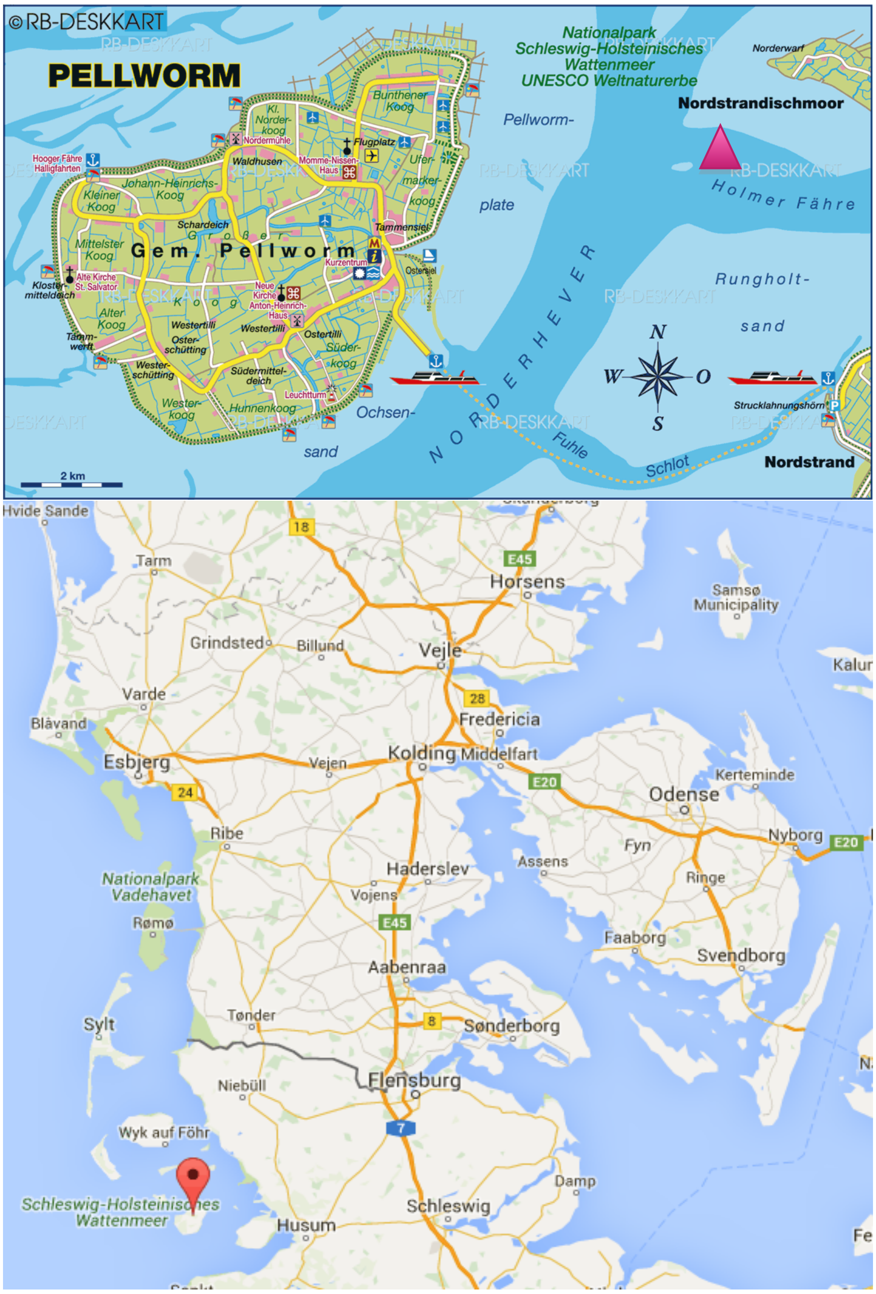


Figure 20: Location of Pellworm (bottom left of map) and Samsø (top right of map) [53]



53 https://www.welt-atlas.de/map_of_pellworm_1-950

A2.4 TOKELAU ISLANDS

Tokelau consists of three small coral atolls that lie between the latitudes 8 and 10 degrees south and between the longitudes 171 and 173 degrees west. Atafu, the most northern atoll, has a surface area of 3.5 km^2; Nukunonu, the central atoll is 4.7 km^2 and Fakaofo, the southern atoll is 4 km^2. From Atafu in the north to Fakaofo in the south, Tokelau extends for less than 200 km and the atolls are 3 to 5 metres above sea level.

Tokelau's population is 1,383. Tokelau currently has no air transportation, and the only means of transport is by sea from Samoa (the trip usually takes between 24 and 30 hours). All travel and supplies into and out of Tokelau originate and terminate in Samoa, Tokelau's closest neighbour.

Tokelau Power Project (TTP)

The Tokelau Power Project (TPP) was funded by the Government of New Zealand and in 2003 TPP published a plan for a fully functional power generation and distribution system for reliable power supply for the next 20 years. The plan included the refurbishment of three diesel-powered generators (one on each atoll) that burned 200 litres of fuel a day, and cost the country nearly $800,000 on an annual basis, providing Tokelauans with electricity 15-18 hours each day.

In 2005 the first solar PV generator was installed, a 10 kWp solar PV 240V AC system including 60 industrial grade solar batteries, an inverter, a controller, and accessories. Initially, the solar system was set up as a mini-grid to supply several households, but it was later fully integrated within the existing diesel supplied power grid of the island of Fakaofo. The project is implemented by the Government of Tokelau and funded jointly by the Government of New Zealand, the Government of France, UNESCO Apia and UNDP Samoa.[54]

Pacific Islands Renewable Energy Project (PIREP)

The next expansion of the solar PV project took place under the PIREP which assessed the barriers to the development and commercialisation of renewable energy systems, in Pacific Island countries. Tokelau participated in a regional technical assistance project with 14 other Pacific Island countries. The project was executed by the Secretariat of the Pacific Regional Environment Programme (SPREP), implemented by UNDP Samoa and funded by the Global Environment Facility (GEF) and UNDP. In 2011, at the Durban Climate conference, Foua Toloa, the head of Tokelau, announced the goal to move to 100% renewable energy by 2012.

This goal was accomplished in October 2012 when Tokelau installed three solar PV generators with a total capacity of close to 1 MW and an associated battery system. Backup power is provided by a bio-energy generator fuelled with locally produced coconut oil.[55] The Government of New Zealand provided funding of $7 million to Tokelau to install the PV systems, and the simple pay-back time due to fuel cost savings was estimated to be around nine years.

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[54] http://blog.rmi.org/blog_2013_09_24_high_renewables_tomorrow_today_tokelau_south_pacific

[55] http://www.tokelau.org.nz/Tokelau+Government/Government+Departments/Energy+and+Telecommunications/Energy.html

A2.5 DEGRUSSA MINE, WESTERN AUSTRALIA

The high-grade DeGrussa Copper-Gold Mine, 900 km north of Perth, is the largest copper producer in Western Australia, producing up to 300,000 tonnes of high-grade copper concentrate annually. The 19 MW diesel power station supplying the mine was recently augmented, with the help of ARENA and CEFC funding, with a 10.6 MW solar PV array and a 6 MW lithium ion battery system.

These capacities required an investment of $40 million which is consistent with the cost assumptions for solar PV and storage in Appendix A3. They result in a 20% reduction in diesel fuel consumption. The mine's new power station is presently the largest integrated off-grid solar and battery storage facility in Australia. The mine site and solar array can be seen in Figure 21 15.

Figure 21: Aerial view of the DeGrussa Mine near Meekatharra

APPENDIX A3: MODELLING INPUTS

Input	Value	Unit	Source
Economic inputs			
Wholesale electricity price	67.1	\$/MWh	ASX SA Base Load Electricity Strip Futures Sep 19 (as at 14/08/2016)
REC price until expiry in 2030	57.0	\$/MWh	ASX REC Futures Jan 21 (as at 14/08/2016)
European forward carbon price	4.94	Euro/tCO2	EUA Futures (as at 14/08/2016)
Emissions intensity of SA electricity	0.5	tCO2/MWh	Data SA SASP target 66 - Emissions Intensity
Exchange rate AUD / Euro	1.46	\$/Euro	Present exchange rate (as at 14/08/2016)
EU carbon price used from 2031	3.61	\$/MWh	Calculated from above 3 parameters
Discount rate	7.0%		Estimate (used for entire 25 years)
Inflation rate	0.0%		Analysis is done in present dollar terms
Demand and tariffs			
Kangaroo Island peak demand (2017)	7.8	MW at 10% POE	According to growth curve in SAPN NNOR
Kangaroo Island peak demand (2041)	13.0	MW at 10% POE	According to growth curve in SAPN NNOR
Demand management potential (2017)	10.0%		ISF based on typical early adoption measures
Demand management potential (2041)	20.0%		ISF based on typical dispatchable demand
Cost of demand management	70.0	\$/MWh	U.S. Energy Information Administration (EIA) 2011 The Annual Energy Review
Residential single-rate 2017-2022 supply	31.78	c/day	SAPN Tariff Structure Statement 2017-2020
Residential single-rate 2017-2022 block 1	15.03	c/kWh	SAPN Tariff Structure Statement 2017-2020
Residential single-rate 2017-2022 block 1	18.05	c/kWh	SAPN Tariff Structure Statement 2017-2020
Business single-rate 2017-2022 supply	31.78	c/day	SAPN Tariff Structure Statement 2017-2020
Business single-rate 2017-2022 block 1	14.59	c/kWh	SAPN Tariff Structure Statement 2017-2020

Input	Value	Unit	Source
Business single-rate 2017-2022 block 2	14.59	c/kWh	SAPN Tariff Structure Statement 2017-2020
Usage rate portion that is TUoS	25.0%		SAPN Network Tariffs from 1st July 2015 (based on residential and LV business actual monthly)
DUoS supply annual rate	31.78	c/day	Calculated (average of residential and LV business)
DUoS usage rate average	11.67	c/kWh	Calculated (average of residential and LV business)
TUoS usage rate average	4.54	c/kWh	Calculated (average of residential and LV business)
Time-series net load data for Kangaroo Island		MW	SAPN 2016 Non-Network Options Report: Kangaroo Island Submarine Cable
Load growth forecast for 2017-2041		MW 10% POE	SAPN 2016 Non-Network Options Report: Kangaroo Island Submarine Cable
Submarine cable			
Capital cost of new submarine cable	36	$ million	SAPN 2016 NNOR: Kangaroo Island Submarine Cable (used centre of range)
Operating cost of new submarine cable	0.5	$ million /year	Estimate arrived at in discussion with HOMER
Lifetime for new submarine cable	35	years	Estimate arrived at in discussion with SAPN
Probability of old cable failing in 2017	10.0%		Page 15 states, "in the 2015-2020 reset period, the cable is likely to fail"
Probability of old cable failing in 2026	10.0%		We presume that the probability of failure is 10% in each year 2017-2026
Solar PV generation			
Capital cost of solar PV generation (large)	2000	$/kW	AECOM
Capital cost of solar PV generation (small)	1500	$/kW	AECOM (includes upfront RECS so REC revenues are not included for small-scale solar PV)
Operating cost of solar PV generation (large)	20	$/MWh/year	AECOM
Operating cost of solar PV generation (small)	0	$/MWh/year	Not applicable to rooftop PV
Lifetime of solar PV generation	25	years	AECOM

Input	Value	Unit	Source
Existing solar PV capacity	1.7	MW	ISF 2016 Network Opportunity Mapping (data made available to this project)
Technology used for utility-scale solar PV		Single-axis tilt	Precedent projects of similar or larger scale
Derating for rooftop compared to utility PV	50.0%		Estimate allowing for fixed panels with non-optimal tilt and location
Time-series output for solar PV generation		MW	ROAM Consulting 2012 Wind and Solar modelling for AEMO 100% Renewables project
Wind generation			
Capital cost of wind generation (1-2 MW)	2000	$/kW	AECOM (provided that usual transport and construction options exist)
Capital cost of wind generation (<1 MW)	3500	$/kW	AECOM
Operating cost of wind generation	20	$/MWh/year	AECOM
Lifetime of wind generation	20	years	AECOM
Time-series output for wind generation		MW	ROAM Consulting 2012 Wind and Solar modelling for AEMO 100% Renewables project
Biomass generation			
Capital cost of biomass generation	5000	$/kW	AECOM confirmed by ERK Eckrohrkessel
Operating cost of biomass generation	20	$/MWh/year	AECOM
Lifetime of biomass generation	20	years	AECOM
Minimum loading of biomass generation	50%		ERK Eckrohrkessel but not applied in model (would be achieved by turning off at night or seasonally)
Energy content of woody biomass	19	GJ/dry tonne	CSIRO 2012 for AEMO 100% RE study
Unit conversion (to MWh thermal)	0.278	MWht/GJ	Conversion factor
Efficiency of electricity generation	27%		CSIRO 2012 for AEMO 100% RE study
Electrical output per dry tonne	1.426	MWh/dry tonne	Calculated from above 3 parameters

Input	Value	Unit	Source
Lower bound biomass price expectation	25	$/green tonne	RuralAus 2011 Kangaroo Island biomass generation plant precursor study: Summary report.
Upper bound biomass price expectation	55	$/green tonne	RuralAus 2011 Kangaroo Island biomass generation plant precursor study: Summary report.
Typical woody biomass cost at mill gate	40	$/green tonne	Calculated – average estimated mill gate cost
Cost of preprocessing woody biomass	39	$/green tonne	Ghaffariyan et al. 2011 Biomass harvesting in Eucalyptus plantations in Western Australia
Moisture content	55%		RuralAus 2011 Kangaroo Island biomass generation plant precursor study: Summary report.
Fuel cost for biomass plant	123	$/MWh	Calculated – used in this form in the model
Battery energy storage			
Capital cost of batteries (energy shifting)	5100	$/kW	AECOM provided 1700 $/kWh for a 3-hour lithium-ion battery
Energy capacity of batteries (energy shifting)	3	hours	AECOM typical example
Capital cost of batteries (balancing)	1250	$/kW	AECOM provided 2000-3000 $/kWh for a 30-minute lithium-ion battery
Energy capacity of batteries (balancing)	0.5	hours	AECOM typical example
Operating cost of batteries	1.5%	of capital/year	AECOM
Lifetime of batteries purchased in 2017	10	years	Estimate
Lifetime of batteries purchased in 2041	15	years	Estimate
Round-trip AC efficiency of batteries	78.7%		AECOM for lithium-ion battery and typical inverter
Diesel and BioDiesel			
Capital cost of diesel generation	1500	$/kW	AECOM
Capital cost markup for biodiesel	10.0%		Estimate
Operating cost of diesel generation	20	$/MWh/year	AECOM

Input	Value	Unit	Source
Operating cost markup for biodiesel	20.0%		Estimate
Lifetime of diesel generation	20	years	AECOM
Cost of diesel fuel on KI	1.22	$/litre	IT Power 2013 Data Collection of Diesel Generators in South Australia (Appendix B)
Efficiency of diesel generation	34%		AECOM (35% for engine running at 50-70% load and 98% generator electrical efficiency)
LHV of diesel fuel	43.2	MJ/Kg	Assumption from HOMER
Density of diesel fuel	0.82	Kg/litre	Assumption from HOMER
Conversion factor	3600	MJ/MWh	Conversion factor
Fuel cost expressed as $/MWh	365	$/MWh	Calculated - used in this form in the model
Fuel cost markup for biodiesel	20.0%		US Department of Energy 2016 Clean Cities Alternative Fuel Price Report (page 17)
Uncertainties			
Uncertainty in cable cost estimate	-30%	30%	SAPN 2016 Non-Network Options Report: Kangaroo Island Submarine Cable
Uncertainty in wholesale electricity price	-20%	20%	Estimate
Uncertainty in cost of solar PV generation	-10%	10%	Estimate
Uncertainty in cost of wind generation	-30%	30%	Estimate (allow for logistics of erecting large turbines on KI)
Uncertainty in cost of batteries	-15%	10%	Estimate
Uncertainty in cost of biomass generation	-50%	50%	Estimate (not widely used in Australia)
Uncertainty in cost of diesel generation	-10%	10%	Estimate
Uncertainty in cost markup for biodiesel	-10%	10%	Estimate
Uncertainty in cost of demand management	-50%	20%	Estimate (effective techniques targeted at KI loads may be inexpensive)
Uncertainty in REC revenue	-10%	10%	Estimate
Uncertainty in RET obligation	-10%	10%	Estimate

Input	Value	Unit	Source
Uncertainty in DUOS	-10%	10%	Estimate
Uncertainty in TUOS	-100%	20%	Estimate (TUOS does not apply if islanded but alternative network support may be levied)
Scenario parameters			
Existing solar PV	1.7	MW	Clean Energy Council
Solar PV capacity in 2017 and 2041	4	MW	Equally divided between utility-scale solar farm and (new) customer rooftop solar
Additional solar PV capacity in scenario 5	2	MW	Additional customer rooftop solar
Wind generation capacity in 2017	8-17	MW	11 MW in scenario 3A, 10 in 3B, 17 in 4A, 10 in 4B, 10 in 4C, and 8 MW in scenario 5
Wind generation capacity in 2041	8-17	MW	20 MW in scenario 3A, 16 in 3B, 28 in 4A, 17 in 4B, 15 in 4C, and 13 MW in scenario 5
Biomass generation capacity in 2017	5	MW	In Scenarios 4C and 5
Biomass generation capacity in 2041	5-10	MW	10 MW Scenario 4C, 5 MW in scenario 5
"Balancing" battery capacity in 2017	3	MW	Scenarios 3A, 3B, 4B, 4C, and 5 (energy capacity is for half-hour discharge)
"Balancing" battery capacity in 2041	3-4	MW	4 MW in scenarios 3A, 3B, 4B, 4C, and 3 MW in scenario 5
"Shifting" battery capacity in 2017	36	MWh	Scenario 4A
"Shifting" battery capacity in 2041	90	MWh	Scenario 4A
Diesel or BioDiesel capacity in 2017	8-10	MW	10 MW in scenarios 2A, 2B, 4B and 8 MW in scenarios 3A, 3B, and 5.
Diesel or BioDiesel capacity in 2041	12-16	MW	16 MW in scenarios 2A, 2B, 4B and 12 MW in scenarios 3A, 3B, and 5.

APPENDIX A4: MODELLING DETAILS

The analysis of supply options for Kangaroo Island has been undertaken using two different energy models: the commercial software Hybrid Optimization of Multiple Energy Resources (HOMER)[56] and RE24/7 which has been developed by ISF staff.[57] This allowed us to have the flexibility to add bespoke features to the RE24/7 model that were helpful for this study, while cross-validating the results obtained by both software models to ensure that the analysis follows accepted industry norms.

The commercial software for micro grid simulation called HOMER has been used to explore an optimal generation mix. This software uses generation capital and operating costs, as well as operational characteristics, as inputs to calculate different combinations of generation technologies and capacities. It aims to find the least whole-of-life cost combination based on energy production simulation to meet the demand. The assumptions made regarding the generation costs and operation are vital for HOMER because the optimisation is cost driven. Thus, a change in the cost assumptions might result in a different energy mix.

To achieve a power supply approaching 100% renewable energy requires broader considerations than the optimisation provided by HOMER, which compares energy supply options according to their net present cost. This is particularly true regarding the treatment of curtailed wind and solar generation, which is calculated as part of the energy balance by RE24/7 and included in the integrated financial analysis through its impact on Renewable Energy Certificate (REC) revenues.

Our modelling approach used HOMER and RE24/7 in a complementary way, with the general process outlined as follows:

- Develop models for several supply scenarios (defined in the next section) using RE24/7 to ensure supply adequacy through a single modelled year at hourly intervals, in order to evaluate the intermittency profile of typical individual years.
- Implement the same models in HOMER and use this software's sensitivity and optimisation tools to explore the cost impacts of changing capacities of each energy supply or storage technology.
- Select preferred supply mixes for each scenario based on cost, curtailment, likely community appeal, and potential for continuous 100% renewable supply.
- Model the same supply mixes in both RE24/7 and HOMER to cross-validate on the basis of cost and energy output per technology.

Table 3 discusses some areas of difference between the models to indicate their relative strengths.

The data presented by this study are calculated by RE24/7 and this software, like HOMER, has limitations compared to software that would be used for a full engineering design. The RE24/7 model is based on a grid analysis tool that uses the commercial MESAP/PlaNet[58] software. The original model simulates power flows across multiple voltage levels including the high voltage transmission level. For the present study, power flows are not modelled and impacts on the

[56] HOMER is an energy modelling software package for designing and analysing hybrid power systems. A trial version of the software can be downloaded free at the website: http://www.homerenergy.com/ .

[57] RE24/7 is based on [R]Evolution which was developed in a thesis by ISF Research Principle Dr Sven Teske (2015), 'Bridging the Gap between Energy-and Grid Models: developing an integrated infrastructural planning model for 100% renewable energy systems in order to optimize the interaction of flexible power generation, smart grids and storage technologies', University Flensburg, Germany.

[58] MESAP/PlaNet is from the German software company seven2one, Karlsruhe: http://www.seven2one.de.

distribution network on Kangaroo Island, which may be beneficial, are not calculated. The analysis is based on hourly intervals, which is not sufficiently granular for assessing grid frequency or simulating other system stability requirements. However, normal engineering practices exist for operating Local Hybrid Solutions of the kind modelled for this study, and they would be within the scope of an engineering study subsequent to this work.

Table 13: Feature comparison between HOMER and RE24/7 modelling software

Feature	HOMER	RE24/7
Models of renewable generation	Sophisticated models including automatic “typical year” solar profiles	Basic models with time series developed manually for solar and wind generation
Models of diesel and biodiesel generation	Sophisticated and richly featured models based on years of user experience	Basic models with assumptions suitable only for a first-pass analysis
Battery operation	Limited choice of operation regimes with batteries used for balancing not energy shifting	Batteries used to store surplus RE and supply residual load
Reliability	Ability to specify contingency reserves	System reserves specified manually with calculated system adequacy measures
Financial analysis	Net present cost in total and per generation technology	Discounted cash flow over modelling period with explicit RECs and other local features

Supply and Demand

The RE24/7 model is an equilibrium model that harmonises demand and supply on Kangaroo Island in hourly steps. Table 14 shows the supply cascade of the RE24/7 model and how it has been used in the calculated scenarios. The chosen preference or dispatch order avoids curtailment of variable solar and wind sources, and minimises fuel use by using diesel generation to supply residual load only after all other energy sources have been used.

Much of the solar generation is small-scale, rooftop PV with RECs accounted for at the time of purchase. Thus, the reason for the preference or dispatch order in Table 14 is to ensure that curtailment reduces the REC revenue of wind generation before solar generation.

Batteries are used to minimise the residual load by storing renewable energy output to the maximum capacity of the battery, and releasing it when there is insufficient renewable energy output to meet load. The battery would also help to manage ramp rates of the biomass and diesel generators, but this cannot be effectively modelled in hourly time steps, and so is not represented in RE24/7.

If the biomass generator is present in a scenario, it is used to its maximum output capacity, assumed to be 5 MW, before diesel generation is dispatched. The biomass generator should, as a steam turbine, be subject to a minimum load requirement; this was not modelled with RE24/7, but was included when using HOMER by scheduling the biomass generator off during low-load periods. This did not greatly affect its total energy output. All scenarios use diesel generation as a contingency power supply and, to varying degrees, for balancing the variability of load and renewable energy. Individual diesel generation units have a minimum load requirement, which was respected when using HOMER, but not modelled with RE24/7, again because it has little impact on the total energy output. The diesel power plant comprises several units that can be turned off individually to achieve a low overall loading.

Table 14: RE24/7 supply cascade (dispatch order)

Technologies	Preference / Dispatch Order	Characteristics
Solar PV	1	Variable – solar radiation
Onshore wind	2	Variable – wind speed
Battery energy storage	3	Limited capacity 0.5–3 hours
Biomass generation	4	Dispatchable – fuel dependent
Diesel generation	5	Dispatchable – fuel dependent

Scenario Configurations

The RE24/7 model was set up to compute energy contributions and net present costs for each of the scenarios sequentially, and to record the results presented in Section 2.3. Fixed and variable inputs are shown in Appendix A3 in an abbreviated format that is not convenient for comparison between scenarios. For greater clarity,

Table 15 and Table 16 show the variable inputs as provided to RE24/7, including the installed capacities of each generation technology and any cost assumptions that change between secenarios. In particular, the cost of diesel plant, maintenance, and fuel is different for biodiesel compared to mineral diesel fuel. The inputs are shown for the modelled years 2017 and 2041, between which an incremental build is assumed including replacement of any plant when it reaches the end of its design lifetime (shown in Appendix A3). A spreadsheet containing the detailed modelling results, and including the time series inputs that could not be represented here in tabular form due to their length, is available on request.

Table 15: Variable scenario inputs to the RE24/7 model for 2017

Scenario	1A	1B	2A	2B	3A	3B	4A	4B	4C	5
PV existing (MW)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
PV utility (MW)	0	0	0	0	2	2	2	2	2	2
PV rooftop (MW)	0	0	0	0	2	2	2	2	2	4
Wind utility (MW)	0	0	0	0	11	10	17	10	10	8
Batteries (MW)	0	0	0	0	3	3	12	3	3	3
Batteries (MWh)	0	0	0	0	1.5	1.5	36	1.5	1.5	1.5
Battery lifetime (yrs)	N/A	N/A	N/A	N/A	10	10	10	10	10	10
Biomass (MW)	0	0	0	0	0	0	0	0	5	5
(Bio)Diesel (MW)	0	0	10	10	8	8	0	10	0	8
Diesel capital cost ($/kW)	N/A	N/A	1500	1650	1500	1500	1500	1650	1500	1650
Diesel fuel cost ($/MWh)	N/A	N/A	365	438	365	365	365	438	365	438
Demand increase	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Demand management	0	0	10%	10%	0	10%	10%	10%	10%	10%

Table 16: Variable scenario inputs to the RE24/7 model for 2041

Scenario	1A	1B	2A	2B	3A	3B	4A	4B	4C	5
PV existing (MW)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
PV utility (MW)	0	0	0	0	2	2	2	2	2	2
PV rooftop (MW)	0	0	0	0	2	2	2	2	2	4
Wind utility (MW)	0	0	0	0	20	16	28	17	15	13
Batteries (MW)	0	0	0	0	4	4	30	4	4	3
Batteries (MWh)	0	0	0	0	2	2	90	2	2	1.5
Battery lifetime (yrs)	N/A	N/A	N/A	N/A	15	15	15	15	15	15
Biomass (MW)	0	0	0	0	0	0	0	0	10	5
(Bio)Diesel (MW)	0	0	16	16	12	12	0	16	0	12
Diesel capital cost ($/kW)	N/A	N/A	1500	1650	1500	1500	1500	1650	1500	1650
Diesel fuel cost ($/MWh)	N/A	N/A	365	438	365	365	365	438	365	438
Demand increase	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%
Demand management	0	0	20%	20%	0	20%	20%	20%	20%	20%