Case Studies RIT-D

It is important to note that all figures provided in this example are for illustrative purposes only. In particular, no inference should be drawn from these numbers as to the value of any actual contract for the provision of Network Support Services.

Theory

Accounting Rules

Residual Asset Value

As network assets typically last significantly longer than the analysis period of any RIT-D study, it is necessary to correct for the differences in effective life remaining at the end of the study period. For instance, a new line built at the start of a 10 year period of analysis has in theory, 10 years less life remaining at the end of the study period than one constructed in the final year of the analysis. This difference is accounted for by adding the depreciated residual value of the asset back into the Net Present Value calculations.

Depreciation is calculated on a straight line basis over the expected life of each asset. As lines, substations and generation equipment each have different effective lives, the expenditure on these items is split into these three categories depreciated over 55, 45 and 20 years respectively. Note that depreciation first appears 12 months after the asset is commissioned (ie on the last day of the following year, such that for an element built in 2014, then it is first depreciated in 2015.

$$Depreciation = \frac{Capital\ Cost}{Life\ of\ Asset}$$

$$Residual\ Value = \sum Capital\ Costs - \sum Depreciation$$

This methodology removes the issue of a study period falling just prior to the requirement for a major upgrade under one option but not others. In this case, the option containing the major upgrade has the bulk of the expenditure added back as the Final Book Value will include most of the option's major expenditure.

Treatment of third party payments

SA Power Networks treats payments to third parties as operational expenditure and assumes that those payments reflect the true economic costs of providing the service. Consequently, we do not assess any 'private' benefit that a third party may obtain from providing the service (eg reduced network connection costs) as we assume that these benefits are used to offset the cost charged to the DNSP; as would occur in an efficient market.

Equivalent Capital Amount

This is the amount of capital that could be spent on a project to improve reliability that can be "paid" for by the savings in VCR loss to the community. This is used as an indicative measure of the break even point at which the marginal cost = marginal benefit.

$$Equivalent\ Capital\ Amount = \frac{Value\_of\_VCR\_benefit}{Discount\_Rate}$$

Inflation Treatment

All costs and benefits are expressed in the same base year dollars in order to remove from the calculations uncertainties about inflation rates etc. This assumes that:

- all costs and benefits change over time at the same rate; and
- all third party service providers have a price escalation clause in their contracts that escalate their charges by the rate of inflation.

Variations in key assumptions

Due to the complexity of the calculations, SA Power Networks typically uses three states of the world – corresponding to a high, medium and low load forecast. For each state of the world corresponding to a different load growth rate we test the sensitivity of the outcome to the following parametric changes:

- Capital costs (SA Power Networks spend only) – base, ±20%
- Costs of capital (discount rate) – Regulated WACC, 10%, 12.5%
- Value of Customer Reliability per MWh - $25k, $50k, $75k per MWh
- Value of losses per MWh - $20, $35, $50 per MWh

This results in a total of 36 different evaluation scenarios for sensitivity analysis purposes. Note that the variations deliberately lie at the extremities of the likely true values in order to capture the sensitivity of the result to these elements.
The advantage of treating potential sensitivities in this manner rather than as states of the world is that they can be parametised within the model and are therefore relatively easy to perform.

Material benefits

Potential impact of embedded generation on Wholesale market

We have looked at this benefit in terms of:

- Impact on wholesale pricing. This is expected to be negligible given the small size of the generator with respect to the overall peak demand in the state.
- Fuel displacement. Close to zero as the only times when the generator is likely to be on is at peak in which case it will be displacing other diesel powered peaking plant.

Consequently we do not believe that there is any potential impact and therefore this class of benefits can be disregarded at the scale typical in the given example.

Electrical losses

In the case study line losses are in the order of 10% to 15% of the electrical demand at the supply point, which is towards the larger end of the spectrum. Following an upgrade they drop to 2½ % giving a calculated saving of over 1,500 MWh per annum. However these savings still form less than 10% of the total benefits from the upgrade. In our experience this is a typical result.
Consequently SA Power Networks argues that the only reason to include changes in electrical losses in any calculation is one of public interest rather than material impact on the result.

VCR from loss of Transformer in a Multi Transformer substation

In our experience the VCR contribution from failures of transformers at multi transformer substations is negligible and can be safely ignored. This is illustrated in the case study attached.

Useful Formula

Loss calculations

SA Power Networks calculates peak system losses from network models and converts these into annual system losses by applying a Load Loss Factor (LLF) and the number of hours in a year.

The LLF is a scalar function, which when multiplied by the peak losses gives the average loss.

$$Annual\ Energy\ Loss\ (MWh) = \ Peak\ loss\ (MW) * hours\ in\ year\ * LLF$$

where,

$$LLF = \frac{Average_{Loss}}{Peak_{loss}}$$

$$LLF = \frac{\sum Values^2}{Count\ of\ values} * \frac{1}{Maximum\ (value\ ^2)}$$

The values are determined using the half hourly SCADA readings over a year.

Value of Customer Reliability

SA Power Networks uses the following formula to calculate the expected annual energy lost due to unplanned outages in MWh. The MWh's are then converted to a dollar value (Value of Risk) and are included within the overall NPV calculation.

$$Value\ of\ Risk = Energy\ at\ Risk * VCR\ value$$

where,

$$Energy\ at\ Risk\ (MWh) = \ Load\_at\_Risk\ (MW) * Period\_of\_Risk * Probability\_of\_\ Outage$$

How the Load_at_Risk, Period_of_Risk and Probability_of_Outage are calculated all depend on the type of risk being assessed.

For a zone substation on a radial sub-transmission line, the following rules are used:

Load_at_Risk = Average Load on Substation (as the outage may occur at any time)
Period_of_Risk = Average repair time of a Sub-Transmission line
Probability_of_Outage = Number of expected line outages per year.

For a constraint that only occurs when load is above a certain threshold we use the following rules:

$$Load\_at\_Risk = \frac{(Forecast_{Peak} - \ Constraint\_Threshold\ )}{2}$$

This division by two, approximates the shape of the load duration curve above the threshold value (ie a triangular approximation).

$$Probability\_of\_Outage = No\ of\ Elements * Element\_Outage\_Rate * \frac{Hours\ at\ Risk}{8{,}760}$$

The Constraint_Threshold represents the capacity of the system with one element out of service, while the Element_Outage_Rate equate to the likelihood of losing this element of the network. Hours at Risk is the number of hours per annum when the load exceeds or is forecast to exceed the Constraint_Threshold. This assumes that the Constraint_Threshold is in excess of the average load on the line or substation.

Therefore, for risks that occur for only a few hours a year, the probability of the outage occurring is very small. This implies that for most systems where there are multiple sources of supply, the VCR value at a DNSP level is also small. An example is, for a two transformer substation where peak load exceeds the emergency rating of a single transformer by 5 MW for 500 hours per year and having a repair time of 4 days (ie 96 hours) and a failure rate of once every 50 years. In this case the expected annual energy at risk is

$$Energy\ at\ Risk\ (MWh) = \frac{(Forecast_{Peak} - \ Constraint_{Threshold}\ )}{2} * Period\_of\_Risk * No\ of\ Elements * Element\_Outage\_Rate * \frac{Hours\ at\ Risk}{8{,}760}$$

$$Energy\ at\ Risk\ (MWh) = \frac{5}{2} * 96 * \left(2 * \frac{1}{50} * \frac{500}{8760}\right) = 0.55\ MWh$$

Based on a VCR value of $50k / MWh, this would equate to an annual VCR value of approximately $27.5k and a capital equivalent amount of $275k; a value far below that required to add a third transformer or upgrade the existing transformers.

1. Distributed Generation in a rural context

Purpose

To illustrate the treatment of:

- Third party generation proposals;
- DNSP generation alternative;
- VCR on a radial sub transmission line;
- Differences in timing of alternative solutions;
- Changes in electrical losses;
- Treatment of differences in network configuration at end of study period.

Background

A radially supplied zone substation servicing a rural area at the end of a long sub-transmission line is facing the following constraints:

- Low voltage at periods of peak demand;
- Line is at thermal loading limit at periods of peak demand;
- Substation transformers are nearing their N capacity and have exceeded their N-1 capacity at peak demand;

The zone substation has 2 x 6.25 MVA 33/11kV OLTC transformers supplying 4 x 11kV feeders. There are no impending 11kV feeder constraints. There is an existing voltage regulator approximately 60% along the sub-transmission line from the source - the installation of an additional regulator is not considered to be a viable option.

Element	Values
Substation peak load [as measured at 11kV Bus]	12 MW / 12.5 MVA at 18:30. Load Factor of 0.33, Loss Load Factor of 0.14
Sub transmission load as measured at source (ie Transmission System Connection Point)	13.5 MW / 15 MVA
Load Forecasts	Medium load growth rate forecast is 2.5%, low forecast is 1.75% and high growth forecast is 3.75%
Customers	About 4,000 customers are supported from the substation with a mix of small industrial, agricultural, residential and commercial loads as typically found in a rural network.
Estimated impact of PV (1)	2 MW at solar noon, 0.5 MW at system peak, growing at 6% per annum. PV impact is included within the forecast growth rate and overall demand forecast.
Sub Transmission line capacity (2)	14 MVA (thermal Limit)
Sub Transmission line reliability data	Average line repair time of 6 hours Average number of outages per annum = 0.4 based on 0.01 outages per annum per km of line.
Sub Transmission line losses (base) (3)	1.5 MW at 12.5 MVA load 0.3 MW at 7.5 MVA

Element	Values
Sub Transmission line losses (after100% new line)	0.3 MW at 12.5 MVA load. Losses to grow at load growth squared (ie I^2R).
Transformer capacity	2 x 6.25 MVA, emergency rating 1 x 7.5 MVA. Transformer reliability of 2.0% per annum i.e. 1 outage every 50 years per transformer. Replacement time of 4 days = 96 hours

Notes

1. PV penetration levels at 25% which is not uncommon in SA.
2. Line already designed and constructed at ultimate design rating. Capacity limit is caused by infringement of statutory clearances.
3. Increase in line losses over those predicted by Ohms Law caused by voltage drop increasing current. All losses estimated from modelling.

Options

1. Private Generation

Third party to build a 5 MVA private peak lopping power station next to the substation to delay the constraints by 7 years. Costs considered are:

- DNSP capital costs = $1 million (new 11kV feeder exit, protection changes, communications upgrade etc.)
- Operational costs of $500 k per year availability fee and run time costs of $25k per year based on fee of $420 per MWh generated (approximately 13 hours per year of generation support).

The power station can run in islanded mode offering partial support to substation following loss of sub transmission line or as system support following loss of a transformer. Contract life of 8 years + 1 x 3 year extension. At the end of the contract, the generator will remain connected and will only generate to the market.

In Year 8, both the third transformer and sub-transmission line upgrade as per option 3 are considered to be required as the load is forecast to exceed the combined capacity of the network and the generation solution. The option to extend the contract for a further three years is to cover the case of low load growth.

Note that these costs do NOT reflect true costs due to commercial confidentiality. Please make this clear in the use of this example.

2. DNSP Generation

As for option 1, however the generation is owned by the DNSP. Costs are:

- DNSP capital costs = $7 million ($1 million to connect plus $6 million for power station). Asset life of 20 years.
- Expected operational costs of $25k per year run time based on $420 per MWh generated and approximately 13 hours per year of generation support.
- Annual maintenance and overheads $100k per year.

The power station can run in islanded mode offering partial support to substation following loss of sub-transmission line.

3. Network Only Solution

Relax constraints by building new network infrastructure according to the following schedule:

Year	Augmentation	Impact	Cost
1	Add third transformer	Delay N constraint on transformers, decrease in losses gives 1 year delay to requirement for new line.	$2 million
2	Build new double circuit line and remove existing line in parallel due to planning permission requirements.	Reduce line losses, increase reliability and improve voltage regulation. Assume rebuilt line is 100% reliable ie can still supply all load following the loss of 1 circuit.	$25 million
8	Build second substation and 3 km of sub-transmission line	Increase distribution capacity	$5 million

RIT-D Elements

Our understanding is that the RIT-D should cover in this case the following elements:

1. Differences in capital and operational costs between the options;
2. Treatment of difference in electrical losses between the options;
3. Difference in system reliability between the options;
4. Potential impact of generation on the wholesale market;

Evaluation of Capital Costs

Table 1 Comparison of Capital costs

Year	Option 1 Third Party Generation	Option 2 DNSP owned Generation	Option 3 Network Solution
2013	$1 M	$7 M	$2 M
2014	-	-	$25 M
2018	-	-	$5 M
2021	$32 M	$32 M	-
Total	$33 M	$39 M	$32 M
Total Depreciation	$0.8 M	$3.5 M	$4.4 M
Residual values (1)	$32.2 M	$335.5M	$27.6 M
Capital NPV	$2.3M	$6.9 M	$15.6M

Evaluation of System Support Operational Costs

These costs include:

- Any annual fee charged by external groups for the provision of system support such as an availability charge
- Any specific maintenance costs or license fees incurred by the DNSP in operating the power station;
- The costs of generating power expressed as a $ / MWh figure multiplied by the MWh generated for peak lopping at the DNSP's request;
- The costs of generating power expressed as a $ / MWh figure multiplied by the MWh generated for running islanded following the loss of the sub-transmission line or a transformer;

Table 2 Option 1 Operational costs for power station

Year	Peak Lopping Load at Risk (MW)	Peak Lopping Hours at Risk	"N" Energy at Risk (MWh)	Cost "N" Support ($k per annum)	Cost "N-1" Support ($k per annum)	Availability Charge ($k per annum)	Annual Total ($k)
2013	0.3	0	0.0	$ -	4.0	$500	$ 504
2014	0.6	1	0.3	$ 0	4.0	$500	$ 504
2015	0.9	1	0.5	$0	4.0	$500	$ 504
2016	1.2	6	3.8	$ 2	4.0	$500	$ 506
2017	1.6	12	9.6	$ 4	4.0	$500	$ 508
2018	1.9	18	17.0	$ 7	4.0	$500	$ 511
2019	2.3	24	27.6	$ 12	4.0	$500	$ 516
2020	2.6	29	37.9	$ 16	4.0	$500	$ 520
2021	3.0	40	59.1	$ 25	4.0	$500	$ 529
2022	3.4	50	83.6	$ 35	4.0	$500	$ 539
Total							5,141
NPV							3,457

As can be seen from the table above, the operational expenses for option 1 are dominated by the availability charge, with the run time costs for both N and N-1 being immaterial. For N, this is due to the low hours at risk and for N-1, the low probability of being called on to generate. Consequently the study is relatively insensitive to assumptions about run time hours and the exact load requested to be generated in any one year.

Option 2 – the DNSP owned generator has a similar pattern except that the annual charge is made up of the cost of maintenance, permits etc. For Option 2 The NPV contribution is $702k.

Network Losses

For the example above, assume that the existing network's losses at times of peak demand is 1.5 MW and after construction of a second line as detailed in Option 3, these losses reduce to 0.3 MW. Similarly, assume that the system's LLF has been determined to be 0.14.

For the line option (which has the largest loss improvement of the three options) it can be seen from the table below that the value of the annual savings is small due to the low average wholesale cost of electricity. For instance, in the first year, the savings in losses from the line upgrade have a capital equivalent amount of approximately $0.5 million. This represents less than 2% of the capital costs of the new line. This is a typical result in even in high loss system such as this example. The returns from the generator options are even smaller as the power station only runs for a few hours a year and the losses occur continuously through out the year.

As an example, in the unaugmented network in year 1 line losses are:

$$Annual\ base\ losses = 1.5 * 8760 * 0.14 = 1{,}840\ MWh$$

And following the construction of the new line losses will drop to

$$Annual\ new\ line\ loss = 0.3 * 8760 * 0.14 = 368\ MWh$$

Table 3 Network Loss savings for new line

Year	Peak Losses	MWh per annum	Loss Reduction Per Annum (MWh) (1)	Value of change ($'000's)
2013	0.30	368	-1,472	-$52
2014	0.32	387	-1,585	-$55
2015	0.33	406	-1,706	-$60
2016	0.35	427	-1,837	-$64
2017	0.37	448	-1,977	-$69
2018	0.38	471	-2,128	-$74
2019	0.40	495	-2,291	-$80
2020	0.42	520	-2,465	-$86
2021	0.45	546	-2,652	-$93
2022	0.47	574	-2,854	-$100

1. Compared to the existing system without improvements at $35 MWh

Value of Customer Reliability

The Value of Customer Reliability calculations can be split into three components:

- Load shedding caused by the loss of the single sub-transmission line supplying the substation;
- Load shedding caused by the loss of either of the two transformers at the substation;
- Load shedding caused by the requirement to operate the line within its ratings (line thermal) forcing the DNSP to disconnect customers at peak times.

Radial line loss

For Option 3 (the new Double Circuit line) the risk of a dual outage of both circuits can be assumed to be small enough that it can be set to zero (ie new poles, new conductors, new insulators, overhead lightning protection and new bus work supporting both circuits).

Options 1 and 2 are identical as the ownership of the generation plant can be assumed to have no impact on reliability.

Table 4 Radial Line available VCR

Year	Base case MWh	Base VCR cost
2013	9.7	$487
2014	10.0	$499
2015	10.2	$512
2016	10.5	$525
2017	10.8	$538
2018	11.0	$551
2019	11.3	$565
2020	11.6	$579
2021	11.9	$593
2022	12.2	$608

Line Thermal

In all three options, no load is required to be shed because of demand forecast not exceeding the line's thermal rating:

- In Options 1 and 2, this is because the peak lopping generation will hold load below the line's rating; and
- In Option 3, the new line has a higher thermal limit.

Consequently no calculations are required as there is no effective difference between the options.

Transformer failure

Detailed calculations are not required as there is no significant difference between the three options.

However, as an example of the scale of available benefits in year 1 of the study, the following calculations are used to determine the maximum VCR that is available in the base case (ie the "do nothing" scenario).

$$Load\_at\_Risk = \frac{(Forecast_{Peak} - \ Constraint\_Threshold\ )}{2}$$

Where the "Constraint _Threshold" is the capacity of the substation following the loss of 1 transformer. The Load at Risk corresponds to the average amount of load that would have to be shed if an outage occurred during a peak period.

$$Load\ at\ risk = \frac{12.5 - 7.5}{2} = 2.5\ MVA \approx 2.4\ MW$$

The probability of the outage using the formula provided previously and assuming load exceeds the N-1 transformer capacity for 737 hours per annum is:

$$Probability\_of\_Outage = 2 * 0.02 * \frac{737}{8760} = 0.0034$$

Assuming it would take 4 days to replace a transformer if it failed (ie 96 hours), The Energy at Risk would equate to:

$$Energy\ at\ risk = 2.4\ MW * 96\ Hours * 0.0034 \approx 0.78\ MWh$$

Therefore, the VCR value attributable to the loss of a substation transformer in year 1 is

$$VCR\ Value \approx 0.78 * \$50k = \$49k$$

These low values are common for transformer outages.

Sensitivity Analysis

The following table illustrates the results of performing a sensitivity analysis for a medium growth rate scenario. In all cases under this scenario, the third party owned generation option is revealed as the preferred choice although it should be noted that it does not have a net benefit to the market under the values used in this example.

Sensitivity Summary

Scenario	Preferred option	Total value	Direct Costs	Benefits	Margin
Default	External Gen	2,062	5,912	-3,850	2,363
Low Discount	External Gen	1,926	6,019	-4,093	2,168
High Discount	External Gen	2,311	5,638	-3,328	2,779
Low Losses	External Gen	2,065	5,912	-3,847	2,363
High Losses	External Gen	2,059	5,912	-3,853	2,361
Low VCR	External Gen	3,985	5,912	-1,927	2,363
High VCR	External Gen	140	5,912	-5,772	2,363
Low Dist Capital	External Gen	1,571	5,421	-3,850	2,363
High Dist Capital	External Gen	2,553	6,403	-3,850	2,363

Direct costs include capital, Operational and Maintenance (O&M) and generation support operational charges. Benefits considered include VCR and system losses. The margin figure is the important column which illustrates that the choice is relatively insensitive to changes in model parameters.