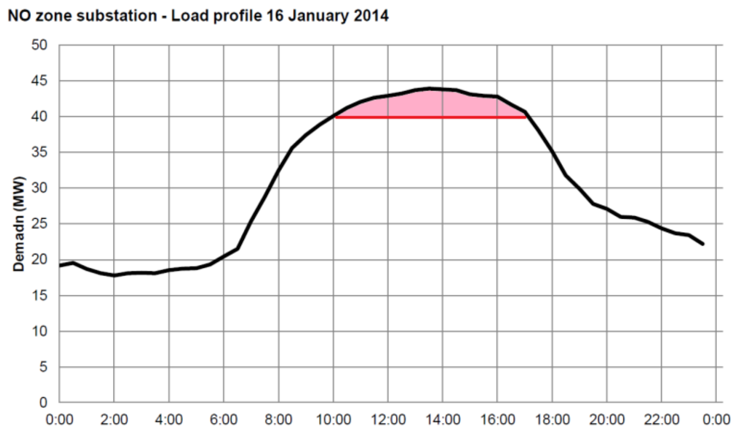
QUESTIONS AND ANSWERS BULLETIN

Notting Hill Supply Area RIT-D Non Network Options

#	Question	Answer
1	Are proponents able to submit proposals with more than one option for evaluation?	Yes
2	Is there spare real-estate available within the Notting Hill zone substation switchyard?	Refer to link: https://www.google.com.au/maps/@-37.8977006,145.1373939,112m/data=!3m1!1e3?hl=en
3	Are proponents able to form a consortia to aggregate non-network services?	Yes provided there is a single contracting party.
4	How many hours of non-network support are guaranteed to be called each year?	The services will be dispatched to address the identified need as described in the Non-Network Options Report. The proponent shall specify in their Proposal any requirement for a guaranteed number of operating hours.
5	Are proponents able to meet with UE to discuss this opportunity?	Yes. One hour duration meetings are available to all proponents. Any information shared with a proponent will be available to all other proponents.
6	How many years of capacity relief will the Notting Hill third transformer provide?	Based on the 2015 load forecast, third 20/33 MVA transformer at the Notting Hill zone substation will provide capacity relief for at least another 15 years.
7	How is the $43,596 per MWh VCR derived?	The VCR of $43,596 per MWh was derived from the sector VCR estimates provided by AEMO in September 2014, weighted in accordance with the composition of the load, by customer type, at the Notting Hill zone substations.

8	Does UE has a technology preference for connecting an embedded generation?	Fault levels are quite high at the Notting Hill zone substation, so any embedded generation connection proposal with be need to be further assessed by our Embedded Generation Connection team in line with the UE Network Access Standards.
9	How does UE calculate the Unserved energy (MWh)?	Unserved Energy per year (MWh) = Load-at-risk per year (MW) * Duration of load-at-risk per year (hours) * Unavailability factor for the critical asset in the zone substation per year
10	How is the annualised cost of network project calculated?	Annualised cost ($) = Capital cost of Network project ($) * UE WACC (6.12%) For the Notting Hill RIT-D, annualised cost of the preferred network project is $370k. It represents the maximum per year allowance, which is available for a Non-Network Option if it can defer the Network project by one year and fully eliminate the unserved energy from the Notting Hill supply area for that year.
11	How has reserve capacity been modelled in the NO RIT-D calculations where load forecast, transfer capacity and energy at risk is concerned?	Reserve capacity is not included in the zone substation load forecast. There are two NO feeders that can be transferred away. These and neighbouring feeders considered for transfers do not have any reserve. Hence reserve capacity has no impact on Energy-at-Risk calculations or the transfer capability limits away from NO.
12	Where a customer is on NO with a reserve capacity on another zone-substation, is this included in NO's transfer capacity? If not, why is this so?	Transfer capacity has not been considered for reserve capacity customers because there is a contractual obligation (for which the customer is paying for the service) for UE to provide the transfer capability for the customer's exclusive needs rather than broader network support for all other customers. For UE to consider this transfer capability as an option in this RIT-D, any option involving the transfer of load away from a primary feeder on NO to a contracted reserve capacity feeder on an adjacent zone substation must be accompanied by a letter from the customer agreeing to: i. terminate the reserve capacity agreement and fulfil any obligations under the agreement relating to early termination,

		ii. pay for recovery of costs associated with abandoning the primary supply which would otherwise have been recovered through customer contributions or DUOS, iii. disable the auto transfer scheme at the customer installation and handover operational control of its switching to UE.
13	Can we submit a proposal for a 20-year project and if so, how would the funding be structured?	A proposal can be submitted for as many year network deferral as reasonably practical. Generally the funding is structured on an annual basis which includes a Capacity availability charge and a dispatch charge, however anyone can propose their own pricing model for our consideration.
14	Does the non-network solution need to be renewable?	No. It can also be a non-renewable solution.
15	What is the no. of hours and MW support profile per day/event?	Depending upon the weather conditions and some other factors: • No. of hours and MW support required per day/event during summer 2017-18 can be as high as 7 consecutive hours and 4.5MW, respectively (as illustrated in the figure below). 
16	There is $142k -$153k of distribution feeder risk benefits in the NNOR.	$142k-153k is the portion of total distribution feeder benefits arising from installing two new distribution feeders, and offloading existing feeders in and around NO supply area. This figure

	a. Which feeders are contributing to this benefit? b. How much benefits is each feeder contributing?	is calculated by comparing the status quo against the reconfigured network with the two new feeders. So these are the maximum benefits available for deferring new feeder augmentations. a. Feeders considered in calculating the benefits include NO 2, 3, 4, 5, 6, 7; GW 3, 5, 10; CDA 11; SVW 41 and MGE 14. It should be noted none of the feeders in this study are expected to exceed their thermal rating under system normal conditions over the next 5-years except for a few highlighted in the NNOR. Given most of the feeders are highly utilised, the risk comes from switching risk (i.e. losing a feeder until it is restored) and Load transfer risk (is there capacity constraint on a feeder when part of neighbouring feeder is offloaded onto the feeder in question under an unplanned outage). The benefits realised due to the new feeders comes from the fact that there are now additional capacity in the network to absorb load from adjacent feeder without overloading, and reduced number of customers on the reconfigured feeders throughout the year. Therefore, if a non-network solution is to say reduce demand on one of the NO feeders, then there will be some portion of the load transfer risk that can be attributed to that proposal as a benefit. By comparison, given the amount of customers exposed to an outage would not change, there will be no switching risk benefit. In order to calculate the amount of distribution benefits (or % of the maximum amount provided in NNOR), UE will need to know the type of solution offered (pre contingent / post contingent), availability of solution, and location to identify the feeder. For the purpose of RIT-D, demand side aggregators can only capture a small portion of new feeder benefits, for the period which coincides with the station risk. b. In year 2018 benefits can be achieved from NO2 (19%), NO3 (2%), NO4 (13%), NO7 (1%) and CDA11 (65%). They are the ones which are being reconfigured (offloaded) as a result of two new feeders at NO associated with the proposed network solution.

17	In the NNOR, CDA-11 has 11% unused capacity. Can you please explain why this is not considered as spare capacity for load transfers away from NO?	Technically there is spare capacity available upstream of CDA11 feeder. However, due to a thermal limitation downstream of feeder, no load can be transferred away from NO onto this particular section of CDA11 during high demand periods.
18	In section 7.2 of the NNOR it is stated that a non-network support offered as a post contingent service would need to be carried out in conjunction with network Option 4 to protect against short term overload. a. Why 2 x 66kVline breakers are required? Shouldn't an ALS scheme be sufficient to protect the assets in the event of an outage? b. Would the ALS scheme shed load down back to the transformer cyclic rating? c. What would be the cost of implementation of an ALS scheme? d. If option 4 did have to be implemented would be the approximate reduction in cost of option 1?	a. One of the reason for a transformer outage would come from the sub-t line fault. The likelihood of a transformer outage occurring due to sub-t fault is higher compared to a transformer failure. However, the impact of transformer failure is significantly more than the sub-t line outage. Therefore, Intention is to provide maintained network security in the absence of NO 3rd transformer augmentation. The ALS would be required to protect the in-service transformer during other transformer failure. Under this case, a number of feeders will need to be tripped automatically to ensure the load is below the cyclic rating of the remaining in-service transformer. We are open to exploring options without 66kV line breakers, however it should be noted that the benefit stream would be diluted with a higher frequency of operation expected from the ALS. b. Yes c. We would need a proposal describing how such a scheme would operate to be able to cost it. However on rough estimates, we expect the cost of ALS scheme could be around \$50k - \$200k. d. Option 4 cost is \$0.75m while Option 1 cost is \$6.0m. The scope of these two options is independent of each other. If Option 4 is implemented, it may only have a marginal impact on the Cost of Option 1, however it may defer the optimal timing of Option 1.
19	In the event of a transformer fault which feeders from GW and SVW can load be transferred to	Loads can be transferred are as per the table below:

and how much of the load transfer capacity is from each feeder?

(in MVA)

From	To	2017	2018	2019	2020
NO 4	GW 3	4.1	4.2	4.3	4.4
NO 4	GW 10	0.9	0.9	0.9	0.9
NO 5	SVW 41	1.3	1.0	0.6	0.6
NO 5	GW 10	0.6	0.6	0.6	0.6
NO 5	GW 5	4.5	4.6	4.6	4.5
NO 7	CDA 11	0.0	0.0	0.0	0.0
Total LTC		11.4	11.3	10.9	11.0

20 What is the building block break down of the $ station risk per year? Can you please explain each of these four categories of station risk?

Station risk has the following four building blocks:

Year	NO Risk	Neighbouring ZS Risk	Distribution Feeder Risk	Risk due to over load shedding	Station Total Risks
2017	$ 36,789	$ 3,056	$ 125,422	$ 6,625	**$ 171,892**
2018	$ 160,042	$ 3,147	$ 132,077	$ 7,067	**$ 302,332**
2019	$ 349,471	$ 3,477	$ 135,655	$ 9,235	**$ 497,838**
2020	$ 486,246	$ 3,849	$ 137,234	$ 10,680	**$ 638,010**
2021	$ 658,887	$ 4,484	$ 141,408	$ 12,523	**$ 817,302**
2022	$ 880,685	$ 5,167	$ 145,705	$ 14,684	**$ 1,046,242**

NO Risk = Notting Hill zone substation risk following a NO TF or a sub-T line outage after considering load transfers. It is not zero post transfers. There is 5.2 MVA load at risk post transfers in the first year. It includes shedding risk following a transformer outage at NO before load transfers can be implemented and is around 3-4% of the station risk at NO in year 2018.

Neighbouring ZS Risk = Following load transfers, amount of incremental risk passed on to the neighbouring (GW, SV/SVW) zone substations. As this becomes a very low probability N-2 contingency scenario .i.e. loss of a TF at NO and the neighbouring zone substation, the value of unserved energy becomes very small.

		<u>Distribution Feeder Risk</u> = Incremental risk on NO and neighbouring distribution feeder network post load transfers after loss of TF at NO. As this also becomes a low probability N-2 condition .i.e. loss of a TF at NO and loss of a distribution feeder, the value of unserved energy becomes smaller then it would have been otherwise. It can be further broken down into System normal, Switching and Overload risk categories. There is no significant system normal risk in the next 5 year period. Incremental Switching risk is the difference in STPIS for a feeder outage before and after load transfers. Incremental Overload risk is the STPIS incurred due to not being able to transfer load from the adjacent feeders because of capacity limitation after a network contingency. **<u>Risk due to overload shedding =</u>** Following the loss of TF at NO, and to keep the loading at NO below 36.5MVA ALS will shed some load until the non-network support kicks in. Due to the discrete size of feeder switch zones, load shed can be more than the required. $6.6k is not the STPIS for full 5.2MVA load shedding. This column only represents the STPIS for incremental customer shed due to the configuration of switch zones on the NO feeders.
21	For the incremental risk on the adjacent zone substations what is the approximate breakdown of incremental risk by zone-substation (GW and SV/SVW)?	100% of the risk is coming from GW ZSS in the first 5 years (until 2021). After that 2-5% of the risk is being contributed from SV/SVW ZSS.
22	For the increment distribution feeder network risk what is the approximate risk breakdown by feeder?	Incremental distribution feeder risk breakdown for 2018 is as below:

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<tr><th>Feeder</th><th>Incremental risk</th></tr>
<tr><td>NO 7</td><td>34%</td></tr>
<tr><td>NO 3</td><td>25%</td></tr>
<tr><td>NO 4</td><td>17%</td></tr>
<tr><td>NO 5</td><td>8%</td></tr>
<tr><td>NO 2</td><td>8%</td></tr>
<tr><td>GW 5</td><td>2%</td></tr>
<tr><td>GW 3</td><td>2%</td></tr>
<tr><td>GW 10</td><td>1%</td></tr>
<tr><td>SVW 41</td><td>1%</td></tr>
<tr><td>MGE 14</td><td>1%</td></tr>
<tr><td>NO 6</td><td>0%</td></tr>
<tr><td>CDA 11</td><td>0%</td></tr>
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<u>Note</u>: The incremental distribution feeder risk at NO is higher following loss of NO transformer, because load transfers from neighbouring feeders on to NO feeders are now restricted due to the N-1 station capacity of NO (due to increase in Overload risk).
GW3, GW5, GW10 and SVW41 have a very small risk increment which is mainly due to the increase in switching risk (due to taking on more customers and extended feeder length).
<u>For example:</u> Under system normal condition there is a load transfer capability from CDA 11 on to NO3. Following loss of transformer at NO ZSS, switching risk will remain the same, however N-1 station capacity at NO will now restrict any load transfers from CDA11 on to NO3 following a fault on CDA11 (overload risk). This incremental overload risk has been weighted by the NO transformer outage probability.
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<td>In doing risk analysis is the incremental feeder risk or neighbouring zone substation risk weighted by the NO transformer outage probability?</td>
<td>Yes.</td>
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24	a. Approximately what % of the incremental feeder risk as in the table in Question 22 is due to having insufficient transfer back to NO due the station capacity? b. Approximately what level of load reduction in MVA would be required on NO to remove this risk by allowing faulted feeders to transfer load back (i.e. if station load was reduced to 30MVA)?	a. It is around 95% in year 2018. b. In 2018, up to 6.0MVA load reduction will be needed at NO substation to eliminate all the 'Overload Risk' component from the distribution feeder risk category.
25	What is probability of failure per annum for a major outage and for a minor outage at NO zone substation?	Probability of failure per annum for a major outage is 0.025 and 0.016 for a minor outage at NO zone substation
26	Of the $6M for Option 1, what is the cost attributable to the establishment of the two new NO distribution feeders which are removing the distribution feeder risk?	Two new distribution feeder cost is around $690k. This is just the cost of the distribution works. It excludes feeder CB costs, relays and protection review etc.