20 November 2014

Mr John Pierce
The Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South
NSW 1235

Dear Mr Pierce,

EPR0039: Optional Firm Access Testing and Design

Thank you for the opportunity to provide input to the Information Sheet: Optional Firm Access Pricing Report as well as pricing model and supplementary information. The AEMC should be commended for the effort of putting together a working prototype model for market participants to experiment with the various methods of transmission network access pricing. DIgSILENT Pacific has observed these developments with interest and attach our report summarising our comments.

DIgSILENT Pacific Pty Ltd is part of the DIgSILENT international group of companies with head office in Germany. DIgSILENT are niche market specialists providing world-best power system analysis software and consultancy services to the electrical power industry. We are the provider of PowerFactory software which is an integrated power system analysis tool that combines reliable and flexible system modelling capabilities, with state-of-the-art solution algorithms and a unique database management concept. We have a strong presence in Australia with offices in Melbourne, Perth, Brisbane and Christchurch. Many Australian utilities, industries and consultants use our PowerFactory software for a variety of applications including network planning, operation and power system investigations.

This submission firstly carried out functional assessments of the prototype and benchmarked the loadflow results using the PowerFactory software. We confirmed some functionalities of the prototype to be correct, but also identified some deficiencies that may result in a distorted outcome.

In the absence of sufficient examples, we tried to compare the post-contingent power flows and access pricing results with theoretical results using a few simple cases. We believe a few working examples will be useful in understanding the calculations as some of the results calculated by the prototype did not align with the expected values.

We believe that with more transparency and better software tools, many of the deficiencies and limitations identified in the submission can be overcome. Recommendations are made in the submission report for the development following an alternative approach.

Our assessment is entirely from a technical perspective and DIgSILENT does not have a view on policy settings and implementation of LRIC and OFA concepts. As a company that works with generation companies, we believe that getting clear and accurate information on the OFA proposals is essential to support new investment. We trust that a transparent process as has been initiated by the AEMC will ultimately result in the best outcome for the power industry. We appreciate the work of the AEMC in this regard.

We are happy to meet with the AEMC to discuss our findings and comments further. Please do not hesitate to contact either myself or Joseph Leung on 03 9820 2320.

Yours sincerely

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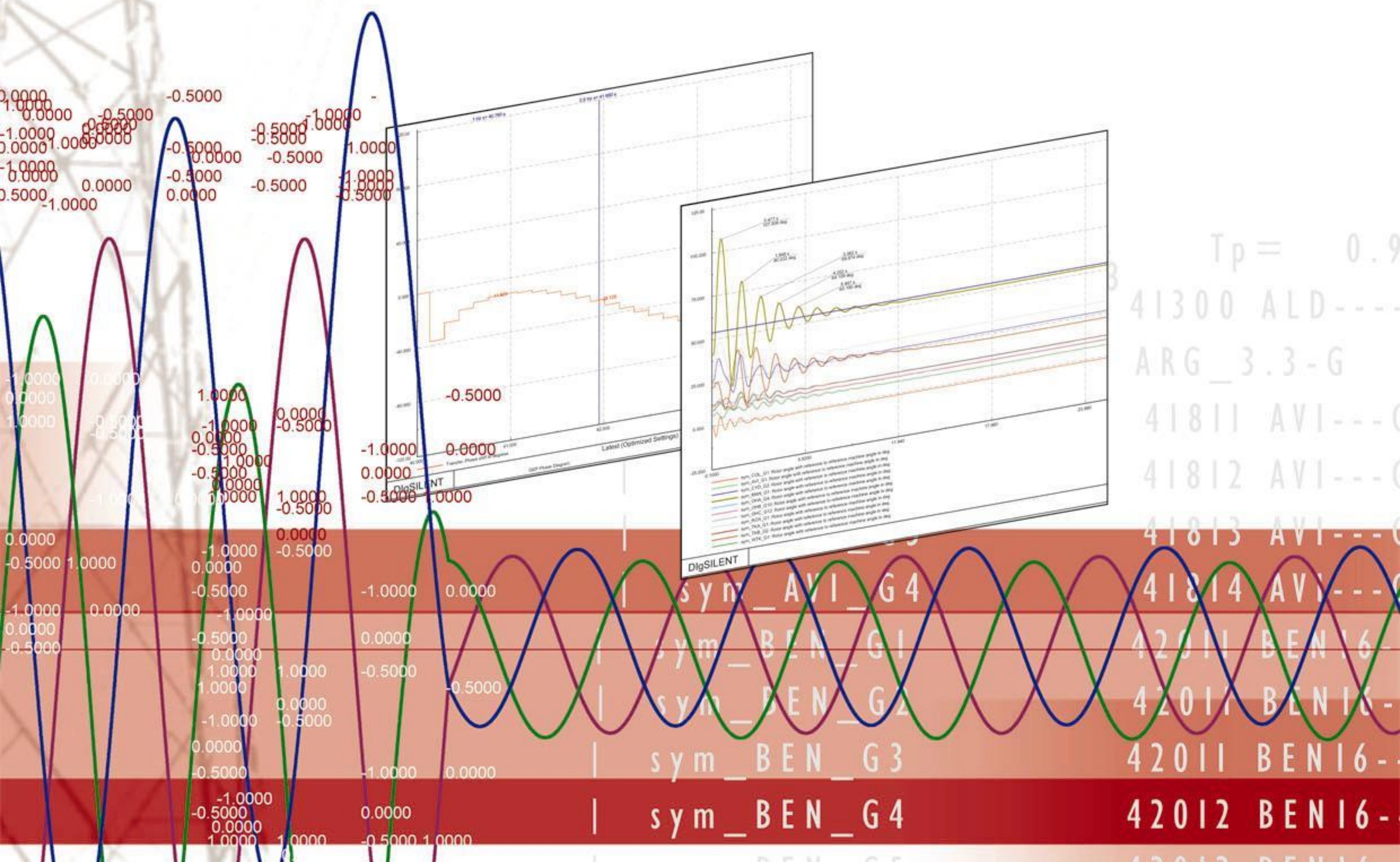
20 November 2014

Submission Paper to AEMC for:

Optional Firm Access Testing and Design Supplementary Report on Pricing

(AEMC Reference: EPR0039)

Revision 1



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Submission for AEMC Supplementary Report on Pricing

Revision history

Revision	Author	Date	Reviewed by	Comments
1	Joseph Leung	20/11/2014	Tim George	Final report for submission

Executive Summary

On 31 October 2014, the Australian Energy Market Commission (hereafter referred to as AEMC) published a Supplementary Report on Pricing [1] for public consultation in relation to the Optional Firm Access (OFA), Design and Testing review. The AEMC invited stakeholders to provide submissions on the Supplementary Report by Thursday 11 December, 2014.

DIgSILENT Pacific Pty Ltd (hereafter referred to as DIgSILENT), is a leading power system simulation software provider and engineering consultancy in the Asia Pacific region, and has been following the latest OFA developments and discussions. The company has an interest in the development of advanced power system tools and the integration of these tools into a range of other enterprise systems. DIgSILENT has carried out independent review of the pricing prototype model using its PowerFactory simulation software. This report presents some of our assessment results of this prototype and our recommendations for improvement.

The prototype model used by AMEC in the pricing report implemented the Long Run Incremental Cost (LRIC) pricing method as specified in the Transmission Framework Review report [10]. It adopted a stylised methodology that assumes away some of the complexity inherent in transmission planning. The prototype has also implemented the Long Run Marginal Cost (LRMC) and Deep Connection Cost (DCC) pricing methods for comparison purposes. While this prototype model is still a work in progress, it has afforded interested parties the opportunity to explore the basics of the OFA proposals. Relevant insight in the pricing mechanism and the optional firm access principles have been gained by the use of this prototype model.

In response to AEMC's invitation for feedback on user experiences, deficiencies of the current model and areas of improvements, we made the following observations:

1. Data and model:
    a. Data used in the prototype does not fully align with the reference sources.
    b. The prototype assumes no inter-connector flows and any increases in the regional firm access are balanced by increasing the "virtual demand" in the Regional Reference Node (RRN). In case of shortage of firm generation, "reliability access" generators are placed within the prototype automatically. Users have no control of the placement of these reliability access generators.
    c. The prototype assumes that the newly installed capacity can be used fully. This ignores need for balancing line impedances that have a direct impact on actual power flow redistribution.
    d. The prototype uses forecast demand, short-term zone growth, long-term zone growth and annual power flow growth rate to determine the power flows along the lines for each year. The forecast demand and short-term zone growth both have effects in the first 9 years but the long term zone growth only affects the demand in the 10th year. The assumption of long term power flow increase is proportional to the rating of each line may create incorrect power flow in the network.
2. Load flow solution:
    a. The loadflow calculation of the prototype model does not produce expected results because it does not calculate the equivalent impedance of multiple parallel branches (lines / transformers) correctly. This will result in incorrect network expansions for the upcoming years.

b. Loadflow calculation has not been performed after a network expansion. This creates incorrect power flow in the augmented network.

3. The dc loadflow solution will result in an average of 0.2% error in power flow and 2% error in bus voltage when compared with ac loadflow solution.
4. The assumption of lossless in the system is arguable. Typical losses in the transmission network of the NEM is about 2.5 – 4.5%.
5. The prototype ignores the real NEM operation such as the typical operating voltage of the transmission network is within 1.03-1.06 pu.
6. It is uncertain how the prototype calculates the post-contingent power flows. The example case shows different theoretical values to the prototype results.
7. Example case also shows different pricing calculations to the prototype results.
8. The prototype appears to be able to demonstrate the relativity of pricing due to different locations and spare capacity between the connection point and the RRN.

This assessment also identifies the following limitations of the prototype:

1. Upgrade option: The prototype currently can only offer duplicates of existing lines or transformers. It should provide more upgrade options and minimize the upgrade cost.
2. Detailed breakdown of costs: the prototype considers the equipment (lines or transformers) costs only. Other costs such as land acquisition, substation design, operating and maintenance costs are not included.
3. Other stability limits: The prototype considers thermal limitation only. The lossless dc loadflow methodology ignores the system losses and cannot assess voltage stability margin.
4. Security adjustment: The post-contingency line flows for the following years is based on the “system normal” loadflow results minus the security adjustment value calculated in the first year. However, changes in the network topology (due to augmentation), generation dispatch and system demand will all affect the post-contingency line flows.
5. Granularity: At present only three ratings are currently available for each type of line. The transmission access can easily be over-priced due to the lack of rating selections.
6. Other operational restrictions: The prototype does not provide any information about other operational restrictions. For example, it is uncertain how much firm access should renewable generators with run-back arrangements should acquire.
7. The prototype cannot handle multiple access requests at different locations and different times.
8. The prototype does not consider committed augmentation projects by the TNSPs.
9. The prototype has not included the replacement cost calculated as required from the Table 10.1 of the in the AEMC Transmission Frameworks Review final report.

We believe the deficiencies and limitations identified above can be addressed and improved. The following recommendations are proposed for the AEMC for considerations:

1. The programming issues of the prototype identified in this assessment, including the misrepresentation of equivalent impedance of parallel elements, should be fixed before the next prototype release.
2. An accuracy requirement should be specified for the prototype in order to better inform the generators in acquiring the transmission access.
3. The accuracy of the prototype can be improved by:
    - Adoption of a full ac loadflow program;

- Enrichment of upgrade options and refinement in the granularity of these options;
- Inclusion of other stability calculations and limits;
- Inclusion of detailed cost breakdown analysis; and
- Detailed calculation of post-contingency loadflow.

4. More considerations should be made in the methodology for calculating the access pricing. In particular:
    - What kind of network scenarios should be used?
    - Should it be regional case or full NEM case?
    - If regional case is preferred, what kind of inter-connector flows should be considered?
    - Should TNSP committed augmentations be factored into the base case development plan?
    - How to deal with multiple access requests?
    - What refinement needs to be made for the RIT-T process?
    - How can generators be more involved in the process of determining upgrade requirements?
    - Should a postage-stamp method be used to calculate the long-term expansion cost given the uncertainty of long-term demand forecast?

CONTENTS

1 Introduction

The optional firm access model aims to minimise the total system cost of building and operating both generation and transmission over time, and so potentially minimise prices for electricity consumers in the longer term.

On 31 October 2014, the Australian Energy Market Commission (hereafter referred to as AEMC) published a Supplementary Report on Pricing [1] for public consultation in relation to the Optional Firm Access (OFA), Design and Testing review. The AEMC invited stakeholders to provide submissions on the Supplementary Report by Thursday 11 December, 2014.

1.1 The pricing model

A prototype model based on a stylised approach was developed to model the power system expansion and to calculate the corresponding long run incremental cost (LRIC). Two additional pricing measures including long run marginal cost (LRMC) and deep connection cost (DCC) were also calculated for comparison purpose. The pricing report presents the development concepts of such model and the result of firm access prices based on the above pricing methods.

1.2 Scope of this review

This review aims to assess the prototype model in the following areas:

- Accuracy of inputs and assumptions;
- Accuracy and correctness of loadflow calculation; and
- Accuracy of pricing calculation.

This report also provides some further comments of the prototype model in general and recommendations for improvement.

2 Functional Assessment

The prototype model being assessed in this report has the following version ID: d1e88a5700edd7aafebad545961dae6e666676ee.

Details of the assessment and results are provided as follows.

2.1 Data and model

Most of the assessments carried out in this section are based on the Victorian case provided in the prototype package. Some basic information of this case is summarized in Table 1 below:

Table 1: Basic information of the Victorian case

Parameter	Value
Number of lines	128
Number of generators	21
Number of transformers	29
2013 firm access	11,273 MW
2013 10% POE demand	13,212.67 MW
2013 reliability access generation	1,393.67 MW

2.1.1 Demand forecast

The key inputs and assumptions of the pricing model were summarized in Table 3.1 of the AEMC Pricing Report [1]. The sources for the information are:

Table 2: Basic information of the Victorian case

Input	Source
Existing access	Results of the transitional access allocation test undertaken by AEMO, which are set out in the Appendix A of the First Interim Report [2].
Forecast access	Generator entry is sourced from data from the 2013 National Transmission Network Development Plan (NTNDP) [3].
Peak local demand	10 year forecasts of peak local demand are from the TNSP's 2013 Annual Planning Reports.

We have compared the values in the sources of references mentioned against the data used in the pricing report and have the following findings:

1. The AEMO transitional allocation test results were included in Appendix B of the First Interim Report. It mentioned the percentage of firm access on a state by state basis but not the allocation of firm access amount to individual generator.
2. The 2013 NTNDP had generator entry information but not the amount of forecast access. We believed that the initial forecast access was based on the registered capacities of the existing generators only.
3. The demand forecasts in the AEMC provided cases (aemc-demand-forecast.csv) do not match with the published information in the TNSPs' APR. For example, Table 3 and Table 4 compare the forecast demands (of NSW and VIC respectively) used in the prototype model against the forecast demands found in the corresponding sources. The results show that:
    a. The demand forecasts used in the prototype (for NSW and VIC case at least) do not match with those in the APRs; and
    b. The Victorian demand forecasts used in the prototype are 25-33% more than the actual and forecast values in the 2013 AEMO National electricity forecasting report [5]. This significant increase in demand forecast will impact on the amount of network expansion required and thus the associated development cost.

We understand that the actual forecast demands are not critical in this prototype model and discrepancies may arise from the processing of demand forecasts at different connection points. However, more realistic demand forecasts should yield a more realistic base expansion plan which in turn will reflect the suitability of the stylised approach for transmission system planning.

Table 3: Comparison of NSW demand forecast (MW)

Year	AEMC prototype	TransGrid 2013 APR 10%POE demand forecast (MW) [4]					
		Summer demand projection			Winter demand projection		
		Fast World Recovery	Planning	Slow Growth	Fast World Recovery	Planning	Slow Growth
2013	12,655	14,100	14,033	13,920	13,456	13,501	13,398
2014	12,655	14,257	14,103	13,946	13,551	13,468	13,319
2015	12,993	14,460	14,152	13,922	13,593	13,544	13,260
2016	13,359	14,865	14,377	14,042	13,895	13,636	13,346
2017	13,598	15,241	14,594	14,020	14,340	13,883	13,449
2018	13,828	15,481	14,840	14,257	14,615	14,138	13,603
2019	14,037	15,653	15,006	14,274	14,841	14,358	13,782
2020	14,242	15,923	15,151	14,374	15,065	14,552	13,850
2021	14,427	16,146	15,322	14,485	15,336	14,741	14,042
2022	14,624	16,177	15,309	14,376	15,492	14,847	14,065
2023	14,803	-	-	-	-	-	-

Table 4: Comparison of VIC demand forecast (10% POE) (MW)

Year	Actual[1]	Prototype	AEMO [5]	Difference
2011	9,267			
2012	9,283			
2013	9,542	13,213	10,530	25%
2014	10,182	13,490	10,697	26%
2015		13,755	10,855	27%
2016		13,966	10,920	28%
2017		14,191	11,046	28%
2018		14,416	11,123	30%
2019		14,660	11,177	31%
2020		14,869	11,276	32%
2021		15,060	11,390	32%
2022		15,251	11,446	33%
Average annual growth		1.6%	0.9%	

2.1.2 Regional case

The prototype calculates the transmission costs on a regional (state) basis. It has the following limitations:

1. There is no power flow through the interconnector. This unrealistic assumption will provide a false signal suggesting no inter-connector reinforcement would be ever required.
2. All additional firm access requests will be matched by the corresponding demand increase at the regional reference node (RRN). For example, the pricing report [1] highlighted in Table C.1 that over 50 per cent of additional demand (on top of the 10% POE maximum demand) is entered into the RRN in the QLD case. In addition, as mentioned in both the pricing report [1] and the EMCA assessment report [6], all sensitive transmission demands were transferred from their original connection nodes to the RRN. These two arrangements will create an unrealistic demand in the RRN and may trigger some unnecessary expansions for the relevant flow paths into the RRN.
3. The prototype will automatically create some “reliability access” generators next to the existing ones when the demand exceeds the total optional firm access generation. This was discussed in Table C.2 of the pricing report [1]. While the report suggests this mimics a situation where a TNSP provides additional generation so that demands-side reliability standards are met, the implemented scenario in the Victorian case is rather unrealistic.

   As mentioned in Section 2.1.1, the Victorian forecast demands were at least 25 per cent higher than those in the AEMO report [5]. As a result, 1939.67 MW of reliability access generation is required in 2013. The distribution is summarized in Table 5. It is obvious that none of these existing generators can double their generation capacity. In addition, these reliability access generators will use up the

[1] *The actual aggregate state demand (including sensitive loads) information is available in the AEMO website.*

transmission capacities available to these generators, potentially forcing these generators to pay higher firm access prices.

Table 5: Comparison of existing and reliability access generation in VIC (MW)

Generator	Firm access	Reliability access
Laverton North	312	309.08
Somerton	160	158.50
Mortlake	566	560.70
Newport	500	495.32
Macarthur	420	416.07
Total	1,958	1,939.67

2.1.3 Stylised duplicate

The prototype adopts a stylised approach that duplicates transmission elements (either line or transformer) by applying a pre-defined "lump" to the network. For example, the transmission line from Eildon PS to Thomastown is a 220 kV line, size "M" with a continuous and short-term ratings of 479.3 MVA. Once the capacity is used up, a new 220 kV size "M" line will be installed in parallel with the existing one. This pre-defined new line (from the linetypes.csv) has a rating of 1450 MVA. The prototype combines the ratings of the existing and new lines and claims that the total capacity is 1,929.3 MVA. However, this is not true in reality because:

- Assuming the two lines having equal impedance[2], power will flow equally through these two parallel lines. The maximum allowable power flow is 958.6 MVA which is two times of the line rating under system normal (N-0) condition. It is because any increase in power flow through these two lines will overload the existing line. In this case, one would wonder why a new line of three times the rating would be built next to the existing line.
- Assuming the new line has a much lower impedance such that 1,450 MVA can flow through it without overloading the existing line[3]. Based on operating security criterion where the loss of one line will need to transfer load onto the remaining line, a maximum of 479.3 MW can only be transmitted from Eildon PS to Thomastown.

2.1.4 Construction of demand growth

The prototype has several methods for constructing the forecast demand:

1. In the period of 2013-2023 (first 11 years), the forecast demand in the aemc-forecast-demand.csv file will be loaded into the program;
2. If no forecast-demand was given for a particular load node, additional "short-term" forecast demand[4] (specified in the zone-growth.csv) will be added to the zone (and distributed among the nodes within the zone) annually starting from the second year within the first 9 years (e.g. 2014-2022);

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[2] *This is unlikely to happen as the two lines have already had different ratings.*

[3] *This is also unlikely to happen in reality as the impedance of every transmission line would be minimized during the design by careful selection of transmission route and conductor material.*

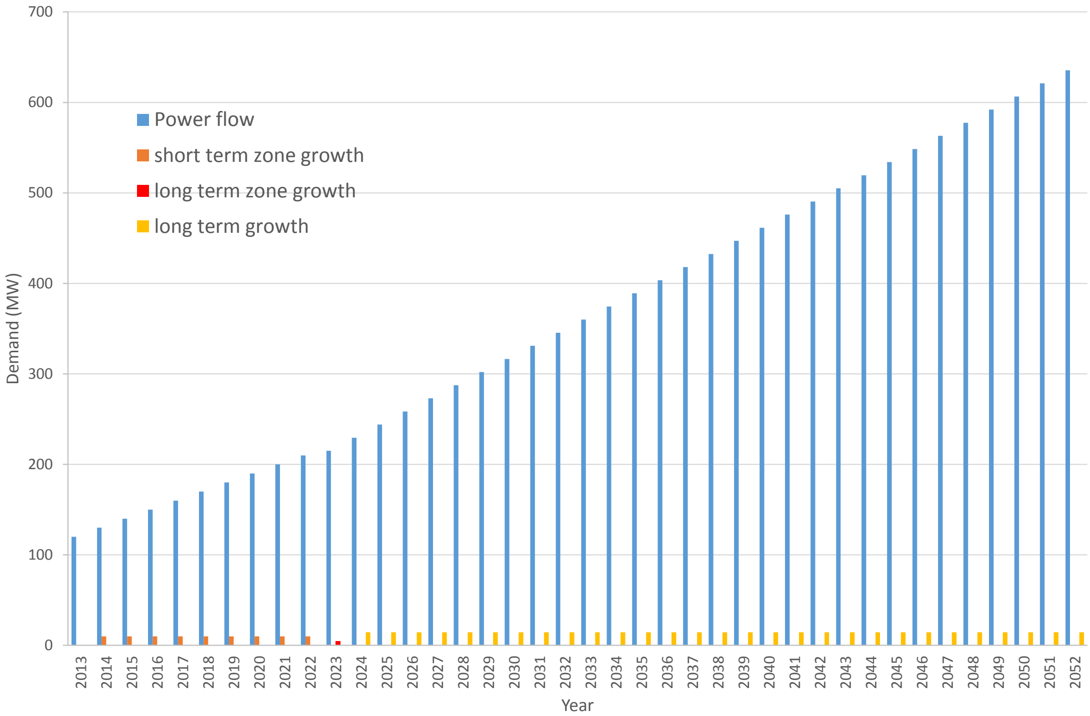
[4] *The zone growth is in MW and the prototype does not allow 0 MW zone growth.*

3. One additional "long term" forecast demand (specified in the zone-growth.csv) will be added to the demand at the 10th year (2023); and
4. From 2024 onwards, because the prototype no longer calculates the power flow in the network using the dc loadflow program, the line flow will be increased annually as a percentage of the rating of the corresponding line type[5]. The percentage is specified in the "flow_model" table of the settings.txt file.

Figure 1 illustrates how the above methods influence the demand at a particular node. Note that:

- the forecast demand for 2013-2023 (method 1) is set to 0;
- the short term zone growth is set to 10 MW;
- the long term zone growth is set to 5 MW; and
- the long term annual growth rate is set to 1% (of a line of 1450 MVA rating).

Figure 1: Impact of short term, long term zone growth factors and long term growth rate on demand forecast



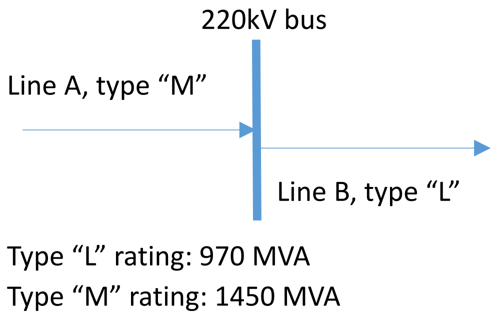
This arrangement raises some questions:

1. It is not easy to work out the contribution of forecast-demand and short-term zone growth to a particular node.
2. The long term zone growth can only influence the demand at 2023. It is believed that this factor will not have any "long term" effect as the future demand is controlled by the annual increase rate of the transmission line power flow instead.
3. From 2024, the annual growth is based on a percentage of the rating of a particular line type[5]. This will create a mismatch in the load flow. For illustration, Figure 2 shows a bus with one incoming line and one outgoing line. In the first 10

[5] *The pricing report [1] writes that the amount of flow on each line is based on a percentage of the peak line flow calculated in the final year that the short term method was applied (Page 27). The analysis carried out in this report suggests the annual increase is dependent on the percentage of the line rating instead.*

year period, the power flow into the bus will be equal to the power flow out of the line as the dc loadflow program is used to recalculate the power flows. However, if we set the long term growth rate to be 1% of the rating of that particular line type, the increase in power flow in line A will be 0.97 MW and that in line B 1.45 MW in 2024. This creates an impossible power flow situation for the network.

Figure 2: Illustration of mismatch in power flow



2.2 Loadflow solution

DIgSILENT has created an equivalent Victorian case using the PowerFactory simulation tool based on the network, demand and generation information from the prototype. This section presents the assessment results.

2.2.1 Original Victorian case

The original Victorian case in PowerFactory (using dc loadflow method) has produced a set of completely different results to the one produced by the prototype. Further investigation has revealed that the prototype did not correctly calculate the equivalence impedance of parallel lines and transformers.

By switching off all additional parallel lines and transformers in the Victorian case, the PowerFactory results match with prototype results, with a maximum error less than 0.1 MW.

To confirm this hypothesis that the dc loadflow calculation did not consider the number of parallel lines or transformers, the numbers of duplicates of the lines and transformers (the dupe entries in the aemc-lines.csv file) are all set to 1 only. The new prototype results show no difference to the original one with different dupe entries. This confirms that this “dupe” entity has no influence to the dc loadflow calculation.

2.2.2 SMIB case example

A single-machine-infinite-bus SMIB case has been used to illustrate the findings in Section 2.2.1. The SMIB case is made by modifying the existing Victorian system in the prototype as follows:

1. Reduce all firm access generations in the aemc-access.csv file to 0 MW and Eildon PS has 120 MW firm access;
2. Reduce all forecast demand to 0 MW in the aemc-demand-forecast.csv;
3. Force the power flow from Eildon PS to Thomastown (RRN) through the direct EPS220-THO220 line and EPS-MBT-DED-SOU-THO path by blocking the other possible branches, i.e. by increasing the impedances of the relevant lines and transformers to infinity. Figure 3 shows the equivalent setup in PowerFactory.

Table 6 compares the load flow results calculated by the prototype against the PowerFactory results. It is clearly seen that the PowerFactory case can only align with the prototype results by switching off all the parallel lines and transformers. Figure 4 shows the equivalent setup in PowerFactory and the corresponding load flow results.

Figure 3: PowerFactory setup

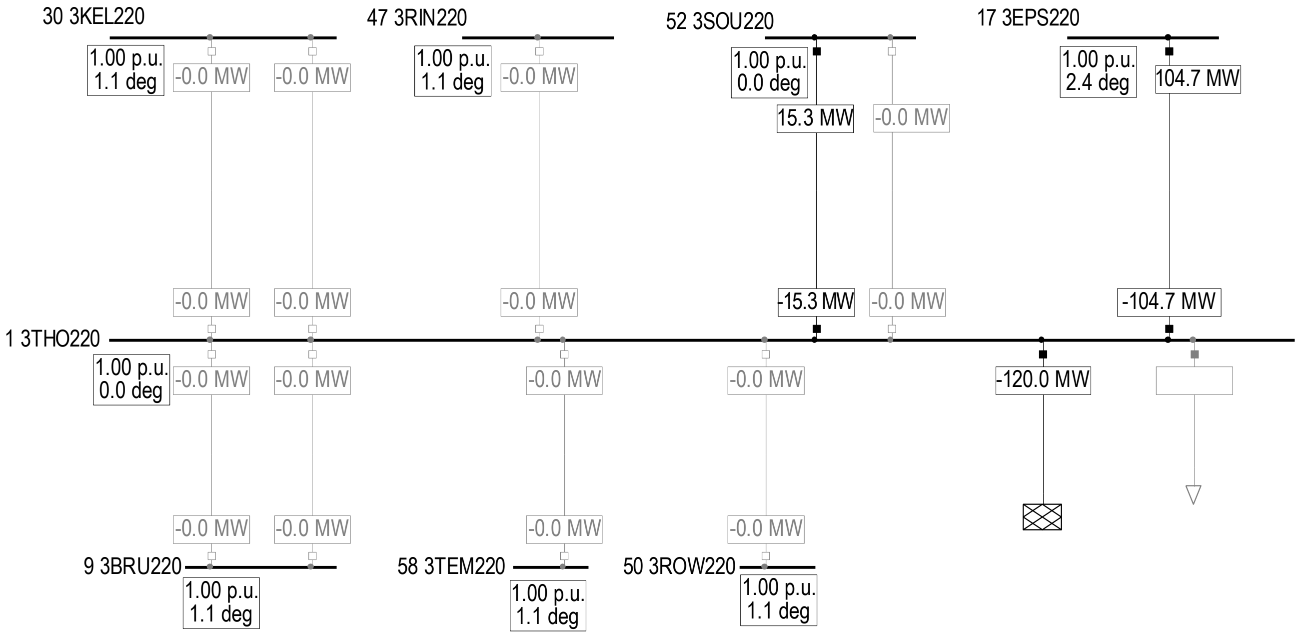


Figure 4: PowerFactory solution (SMIB)

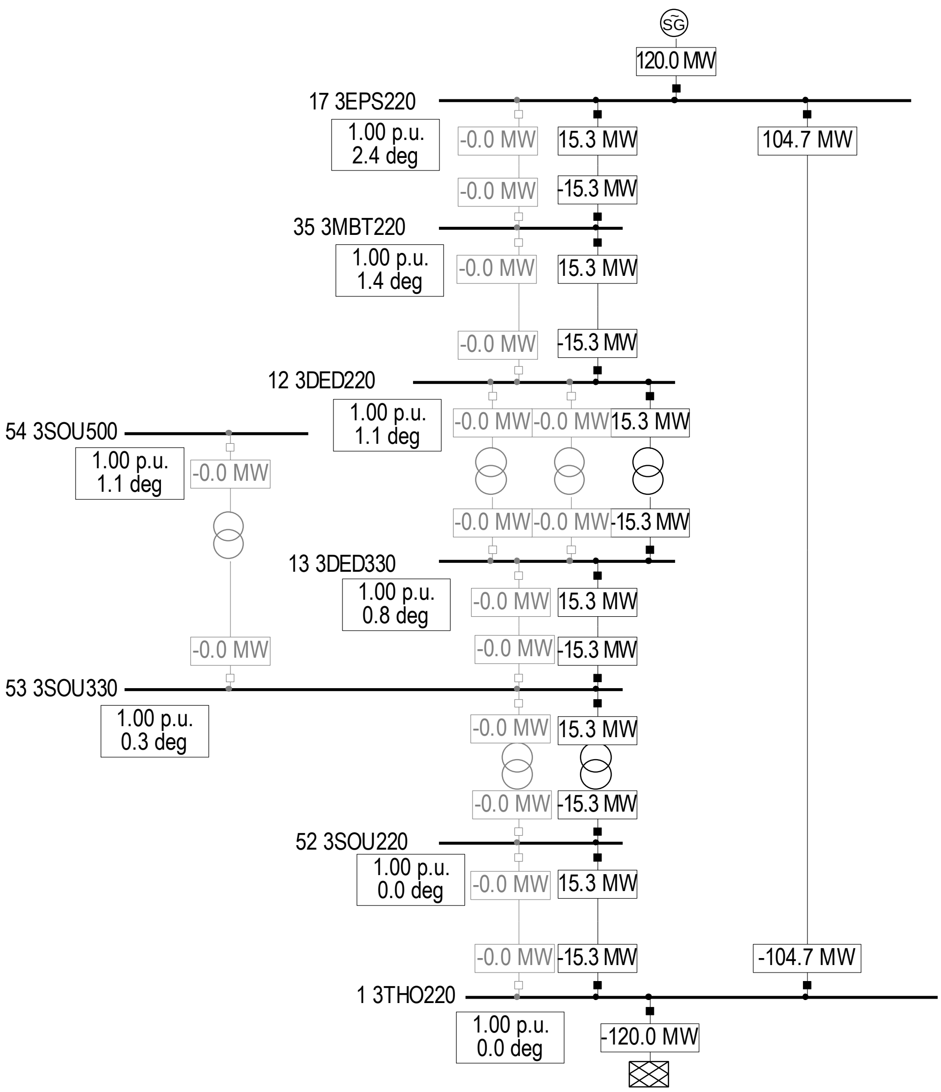


Table 6: Comparison of PowerFactory and Prototype results (SMIB)

	Flow (MW)		
Line	PowerFactory (system normal)	PowerFactory (parallel line OOS)	Prototype
EPS220-THO220	92	104.7	104.7
EPS220-MBT220	14	15.3	15.3
MBT220-DED220	14	15.3	15.3
DED220-DED330	14	15.3	15.3
DED330-SOU330	14	15.3	15.3
SOU330-SOU220	14	15.3	15.3
SOU220-THO220	14	15.3	15.3

2.2.3 Network expansion

This case aims to examine how the prototype handles the additional elements due to the network expansion. The same SMIB case in Section 2.2.1 was used here. This time, the Eildon PS generation has changed from 120 MW to 620 MW (500 MW firm access request). This will trigger the addition of a second EPS220-THO220 line, which has a rating of 1450 MVA according to the stylised approach. The loadflow results are shown in Table 7. The results show that the prototype does not re-calculate the new network impedances and the load flow solution is therefore not correct.

Table 7: Comparison of PowerFactory and Prototype results (Expansion)

	Flow (MW)		
Line	PowerFactory (with additional line)	PowerFactory (without additional line)	Prototype
EPS220-THO220	577.7	540.9	540.9
EPS220-MBT220	42.3	79.1	79.1
MBT220-DED220	42.3	79.1	79.1
DED220-DED330	42.3	79.1	79.1
DED330-SOU330	42.3	79.1	79.1
SOU330-SOU220	42.3	79.1	79.1
SOU220-THO220	42.3	79.1	79.1

2.3 dc loadflow versus ac loadflow

With a validated Victorian network model[6] in PowerFactory, this section examines the differences in load flow results using ac and dc loadflow techniques. The differences in bus voltage and power flow are summarized in Table 8. The results show that there is an average of 2% error in bus voltages with a maximum difference of 0.13 pu. This is due to the dc loadflow assumption that all bus voltages are at unity. The differences in power flow along the lines are comparatively smaller, with an average of 0.2% difference.

[6] *The Victorian case with all parallel lines and transformers switched off cannot be solved by ac loadflow due to the excessively high impedances in the network.*

Table 8: Comparison of dc and ac loadflow solutions

	Voltage difference (pu)	Loading difference (%)
Maximum	0.13	1.7
Average	0.02	0.2
Standard deviation	0.03	0.5

2.4 Lossless loadflow solution

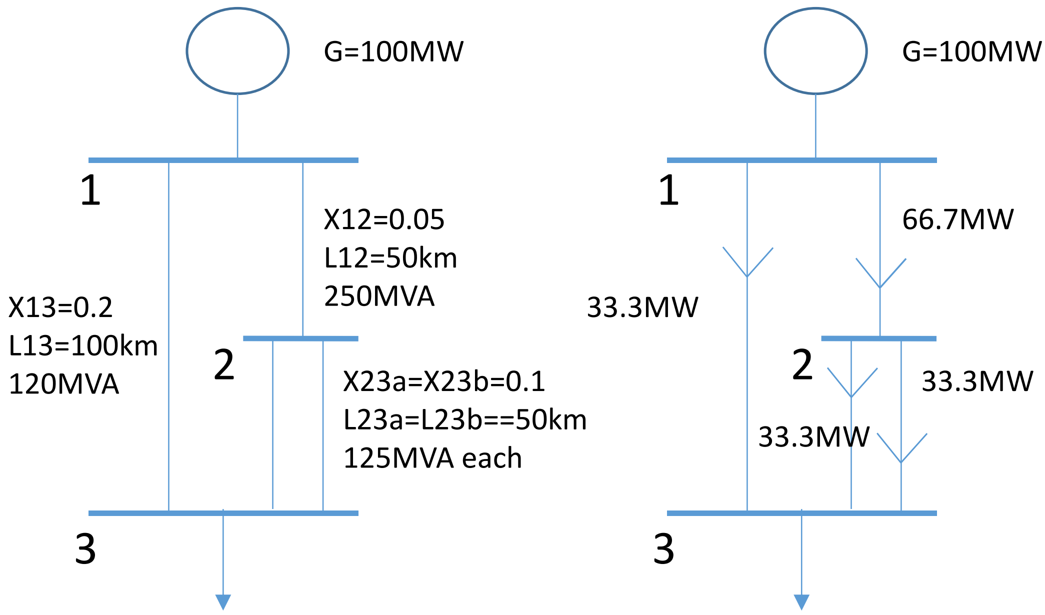
The prototype assumes no losses in the transmission network. This is an arguable assumption. According to the AEMO's marginal loss factor report [7], the losses in the NEM transmission network are typically around 2.5 – 4.5% of the power transmitted, while losses in the distribution networks may be much higher. The removal of loss consideration may simplify the dc loadflow algorithm, at the expense of accuracy in the load flow solution.

2.5 Contingency analysis

In order to compare the post-contingent power flows and the security adjustment results, a simple 3-bus example was constructed using the prototype. The single line diagram of the example and the pre-contingent loadflow solution are shown in Figure 5. The data used in this example is provided in Appendix A. The theoretical N-1 post-contingent power flow through the lines are shown in Table 9. The post-contingent power flows through the lines calculated by the prototype are shown in Table 10. It is shown that:

- The post contingent spare capacities of lines 1-3, 1-2 and 2-3a are similar to the theoretical values but not exact; and
- The post contingent spare capacities of lines 2-3a and 2-3b are not the same while the properties of these two lines are identical.

Figure 5: 3-bus example and loadflow solution



It is unclear how the contingency analysis of the prototype works. It is important for the next release of the prototype to provide sufficient examples to demonstrate this function. It is worth mentioning that this contingency analysis function is common in most of the established power system software such as PowerFactory and PSS/E. These programs will calculate the post-contingency power flow by performing another loadflow study because of the change of network topology will redistribute the power flow in the network non-linearly.

Table 9: Theoretical N-1 post-contingent power flows

Line	Post-contingent flow (MW)	Post-contingent spare (MW)	Worst case contingency
1-3	100	20	Loss of 1-2
1-2	100	150	Loss of 1-3
2-3a	50	75	Loss of 1-2
2-3b	50	75	Loss of 1-2

Table 10: Post-contingent power flows from the prototype

Line	cts rating	pre contingent flow	pre contingent spare	post contingent spare	adjust
1-3	120	33.33	86.67	19.44	67.23
1-2	250	66.67	183.33	149.44	33.90
2-3a	125	33.33	91.67	74.72	16.95
2-3b	125	33.33	91.67	67.54	24.13

2.6 Pricing calculation

The 3-bus example in Section 2.5 is used for checking the access pricing results. An additional 200 MW of firm access was requested at Bus 1, making 300 MW of power flow from Bus 1 to Bus 3. The new power flow solution is shown in Figure 6. With the post-contingent power flow exceeding the rated capacity of 120 MVA, an upgrade of Line 1-3 is required. According to the prototype solution, the lumpiness of Line 1-3 is 3, and the line type of Line 1-3 has a capacity of 200 MVA. Therefore, a line of 66.7 MVA will be added in parallel with Line 1-3, making the total capacity = 186.7 MW.

The pricing results calculated by the prototype are summarized in Table 11.

Figure 6: New loadflow solution of the 3-bus system

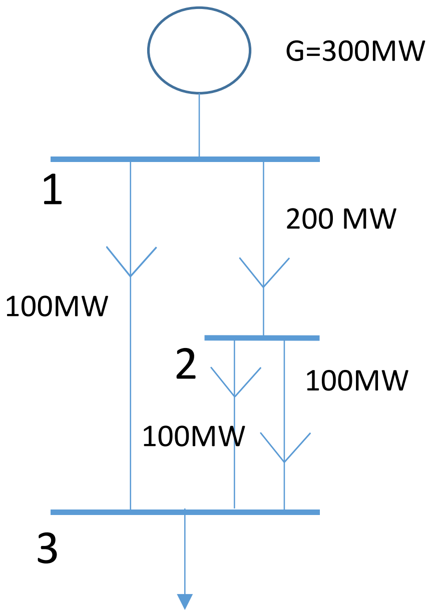


Table 11: Access prices

Access cost	LRIC	LRMC	Deep C
$/kW	28.84	50	16.35

In this example, the cost of the new line is calculated as follow:

Cost per km per MW = $500

Line length = 100 km

Therefore, cost = $500 x 100 /MW = $50/kW. This equals the LRMC value.

The deep connection cost (DCC) will be the amount of money spent divided by the lumpiness of the line (which is 3) = $16.67/kW. This is similar but not exactly equals to the calculated cost.

It is uncertain how the LRIC is calculated in this case.

In order to explore further about the pricing calculation, the ratings of all the lines in the 3-bus examples are reduced such that a base case expansion for each line is required and an additional line (3rd line) is required for Line 1-3. The changes in line ratings are summarized in Table 12. In theory, the access price should only cover the additional upgrade of Line 1-3 which is not in the original base expansion plan, i.e. the costs should be the same as those in Table 11. However, Table 13 shows that the LRIC and DCC are different from those in Table 11.

In this revised example, however, the DCC aligns with the theoretical value. The LRIC can also be calculated by dividing the deep connection cost by the factor of (1+WACC) = $16.67 / (1+0.064) = $15.66.

However, as the augmentation actually happens in the first year, it is uncertain whether there is a need for the LRIC to calculate the NPV for the first year.

In summary, attempts have been made to understand the calculation of different access prices. However, due to the lack of transparency and examples, different access prices were produced even for the same augmentation. It is important for the next release of the prototype to provide sufficient examples to demonstrate the calculation of these access prices.

Table 12: Changes in ratings

Line	Old rating (MVA)	New rating (MVA)
1-3	120	100
1-2	250	100
2-3a	125	50
2-3b	125	50

Table 13: New access prices

Access cost	LRIC	LRMC	Deep C
$/kW	15.66	50	16.67

2.7 Pricing results

Due to the issues identified in the above sections, we believe more work is required to refine the prototype in its current form. We agree with the AEMC and EMCa findings that the pricing results produced at this stage can provide some rough ideas about the sensitivities of the LRIC method to the level of spare capacity and distance between the connection node and the RRN.

We are unable to further comment on the pricing results at this stage.

2.8 Real NEM operation

Apart from the issues identified in Sections 2.1 to 2.4, the prototype also has some other deficiencies in light of the real NEM operation. The deficiencies are:

1. The real transmission network typically operates at 1.03 to 1.06 pu voltage (instead of 1.0 pu in the prototype). Higher operating voltages reduce the line flows proportionally. This will effectively delay the timing of expansion and thus reduce the LRIC price.
2. The dc loadflow program cannot provide any information about system voltage. This limitation prevents the program from the investigation of any voltage stability constraints and determination of reactive power margins. The cost of reactive power compensation elements (e.g. capacitor banks, shunt reactors, and SVCs, etc.) will not be factored into the LRIC calculation.
3. Standard designs are typically adopted for transmission lines in a particular region. However, variation in line route and design standards (such as EMF) may mean that there are variations between two ostensibly similar lines. The current approach does not capture these variations. The cost calculated by this stylised approach cannot capture the complexity involved at present.

3 General discussions

3.1 Prototype limitations

It is understood that the prototype using the stylised approach only aims to provide an approximation of the access price. However, it is important to determine the level of accuracy that the prototype results can meet. This will give the generators more confidence in purchasing the access. The prototype accuracy can be improved in the following areas:

1. Upgrade option: The prototype currently can only offer duplicates of existing lines or transformers. The prototype should provide more upgrade options and minimize the upgrade cost.
2. Detailed breakdown of costs: The prototype considers the equipment (lines or transformer) costs only. Other costs such as land acquisition and substation design, supplementary voltage control devices (capacitors, SVCs), operating and maintenance costs are not included.
3. Other stability limits: The prototype considers thermal limitation only. For example, the pricing report [1] mentioned that the LRIC calculated on the generation corridor between Latrobe Valley and Melbourne was low because the other stability constraints were not considered in the prototype. However, the lossless dc loadflow methodology ignores the system losses and cannot calculate voltage stability margin. Other more established ac loadflow method should be used to give a more realistic system solution that will also provide information to other stability limitations.
4. Security adjustment: The post-contingency line flows for the following years is based on the “system normal” loadflow results minus the security adjustment value calculated in the first year. However, changes in the network topology (due to augmentation), generation dispatch and system demand will all affect the post-

contingency line flows. It is recommended to re-calculate the post-contingency line flow for every year.

5. Granularity: At present only three ratings are currently available for each voltage level. The transmission access can easily be over-priced due to the lack of dynamic rating selections. Refinement in the granularity can improve the pricing accuracy immediately.
6. Other operational restriction: The prototype does not provide any information about other operational restrictions. For example, it is uncertain how much firm access renewable generators with run-back arrangement should acquire.

3.2 Treatment of multiple access requests

The prototype at this stage can only calculate the access request one at a time. This creates two potential issues:

1. Locational issue: If there are two generators at two locations which are far apart requesting firm access at the same time, the prototype cannot co-optimize the two requests and produce a more economical augmentation solution.
2. Temporal issue: Assume two generators request firm access at the same location but at different times, if the first generator's firm access request triggers a network expansion, new spare capacity will be created because of the lumpiness nature of network augmentation. The second generator may be able to enjoy a free ride as long as its firm access request does not trigger any further expansion needs.

3.3 Treatment of TNSPs' committed augmentation projects

At present, the prototype calculates the access prices based on the network configuration of the current year and forecast demands only. TNSPs' committed network augmentations for the next few years as published in the APRs are not included in the base case expansion plan. If any generator triggers the development of these committed projects, the prototype currently does not have any function to exclude these projects from the access price calculation. This may result in double-counting the cost.

3.4 Peak demand case

The use of one regional peak demand case only to determine the transmission access price may not reflect the more relevant congestion issues a generator faces. For example, wind farms in South Australia tend to output more at night time when SA system demand is relatively low. TasNetworks also reported that Tasmania's peak demand occurs in winter whilst network thermal constraints occur during summer [1].

The First Interim Report [2] suggests the firm access planning standard to be based on system conditions, including a predefined set of contingencies specified by the TNSPs and approved by the AER. It is worth considering the use of multiple system scenarios to determine the access price. For example, AEMO calculates the cost of shared transmission services by using the average of the transmission customer's half-hourly maximum demand recorded at a connection point on the ten weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during the most recently completed 12 month period (t-1), expressed as $/MW [9]. The final transmission access price can be calculated as the average of the transmission prices calculated over a set of scenarios agreed between the TNSP and the generators.

3.5 Full NEM case

The regional peak demand case used by the prototype at present does not consider inter-connector flows and assumes all additional power generated is absorbed at the RRN. This arrangement will promote more connection upgrade in the flow paths connected to the RRN and ignore the needs for inter-connector upgrade.

An alternative is to use a full NEM (5 state) model to calculate the access price. AEMO in the NTNDP process creates a 5-state full NEM loadflow model that takes into account of committed augmentation and forecast demands (of each state) for the next 10 years. Using the same set of loadflow cases from NTNDP will promote more consistency in the development plans.

3.6 Review of the RIT-T process

The Transmission Framework Review [10] suggested that the key aspects of the planning process would be the same as currently, with TNSPs being required to produce both APR and RIT-T planning documents. TNSPs would be required to plan to meet both the firm access and reliability standards. However, the RIT-T assessments will no longer include benefits and costs that accrue to generators as they would be able to directly indicate their preferred access levels.

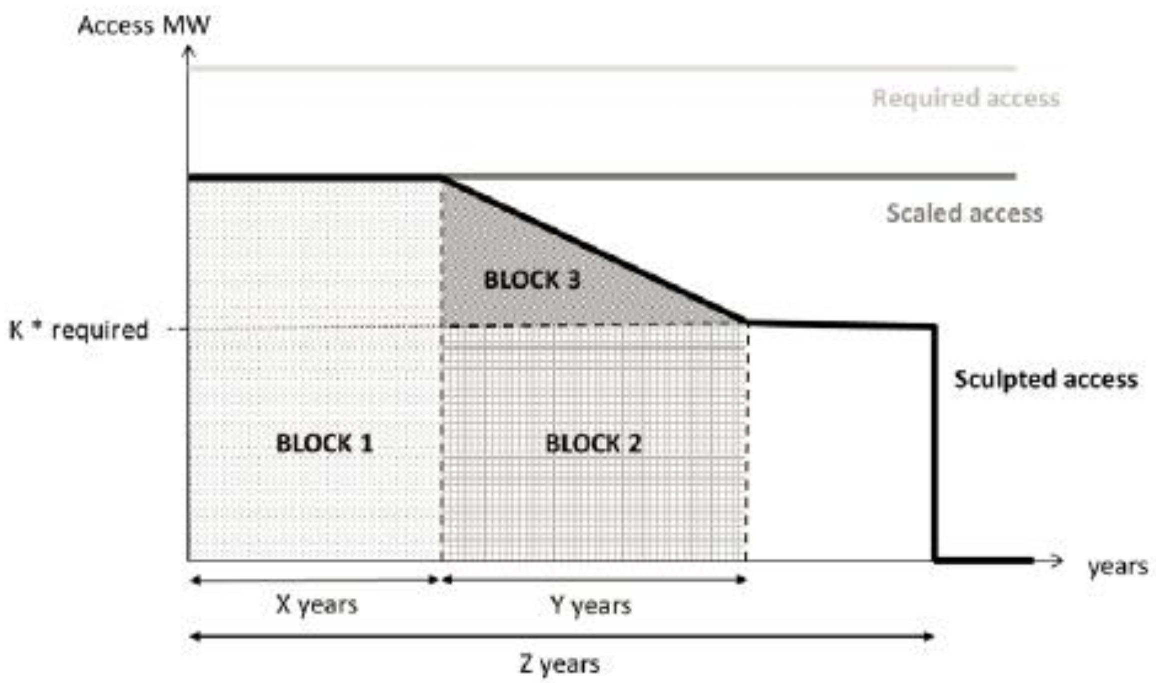
It is however unclear how the process will work. Will a generator sponsored network augmentation (through the transmission access cost) still require a public consultation and approval by the AER? Will the difference between the final project cost and the agreed transmission access cost be the reliability standard cost that the TNSP will bear?

3.7 Sculpting of transitional access

The First Interim Report [2] proposed an initial firm access allocated to existing generators, followed by a sculpting process that reduces the grandfathered access within a period of time. Figure 7 shows the sculpting of transitional access for a power station. The process is determined by the following four parameters:

- X, the "learning period" over which initially allocated transitional access would not be sculpted back;
- Y, the period of time over which initially allocated transitional access would be sculpted back to provide a gradual transition;
- K, the proportion of a generator's capacity to which transitional access would be sculpted back over the Y period and then retained until Z years elapse; and
- Z, which is a proxy for the residual power station life.

Figure 7: Sculpting of transitional access for a power station (Figure 9.1 of [2])



The prototype model provides some insights into the selection of these four parameters:

1. The total amount of initial firm access allocation to generators should not cause any base case expansion in the first year (i.e. the firm access standard is met);
2. In a low demand growth scenario, where the future demand forecast is not large enough to trigger any base case expansion plan and there is no new generation requesting firm access, the cost for any existing generator to buy back its firm access after sculpting (Z years) will be zero or minimal. If this happens, it is very likely that the existing generators will buy back the firm access with a zero or minimum price. The existing generators would also like to reduce the transition period (e.g. X, Y and Z) such that they can buy back their firm accesses as soon as possible.
3. In summary, the longer the transition process, the less will be the spare capacity and the more the generators will need to pay for their firm access after sculpting.

4 Recommendations

The following recommendations are made based on our assessment of the prototype:

1. The programming issues of the prototype identified in this assessment, including the misrepresentation of equivalent impedance of parallel elements[7], should be fixed before the next release;
2. An accuracy requirement should be specified for the prototype in order to better inform the generators in acquiring their transmission access;
3. The accuracy of the prototype can be improved by:
    - Adoption of a full ac loadflow program;
    - Enrichment of upgrade options and refinement in the granularity of these options;
    - Inclusion of other stability calculations and limits;
    - Inclusion of detailed cost breakdown analysis; and
    - Detailed calculation of post-contingency loadflow.
4. More factors should be considered in the methodology for calculating the access pricing. In particular:
    - What kind of network scenarios should be used?
    - Should it be regional case or full NEM case?
    - If regional case is preferred, what kind of inter-connector flows should be considered?
    - Should TNSP committed augmentations be factored into the base case development plan?
    - How to deal with multiple access requests?
    - What refinement needs to be made for the RIT-T process?
    - How can generators be more involved in the process of determining upgrade requirements?
    - Should a postage-stamp method be used to calculate the long-term expansion cost given the uncertainty of long-term demand forecast?

[7] *As a temporary fix, user can ignore the "dupe" entries in the aemc-lines.csv file and create the required parallel lines or transformers by putting another record (row of data) in the file.*

5 Specific questions raised in the AEMC report

Our comments on the specific questions are summarized in Table 14.

Table 14: Comments on specific questions raised in the report

Item	Question	Comment
1	Could it be possible to improve the model to produce prices that are reflective of incremental transmission costs?	Yes. We believe an accurate ac loadflow calculation method and a detailed augmentation plan for the first 10 years will improve the modelling accuracy. As it is hard to develop accurate forecast beyond 10 years and the prototype suggested that long term expansion plan has little effect on LRIC, a postage stamp method may be considered instead.
2	If not, why not?	Ultimately, as the pricing report suggested, the LRIC pricing is significantly dependent on the assumptions made. While the accuracy of the pricing model can be improved using more accurate computation method, the LRIC pricing will still be heavily dependent on the assumptions.
3	How does the model need to change?	The model needs to be able to take into account of real network augmentation options. Intelligence is also required to assess if the proposed expansion plan is economical and practical. A detailed base plan and adjustment plan is preferred than this stylised approach.
4	What inputs need to change?	The expansion cost, the amount of reliability generation and the use of the long-term zone growth factor and the concept of using long-term growth rate for the transmission line.
5	Inclusion of stability constraints	It is important to include stability constraints in the LRIC computation. Voltage stability can be easily computed using a proper ac loadflow program. It is more difficult to consider transient and small signal stabilities as the dynamics of the generators have direct impacts on these stability limits.
6	the ease of usability of the model, and whether there are additional features that could make the model easier to use	In general, the program is easy to operate. However, there are not enough examples to guide the user through the design concepts.

7	the inputs, and assumptions that have been used in the model	Proper references to the sources of the inputs are required.
8	the outputs of the model, including whether it could be possible to improve the model to produces prices that are reflective of incremental transmission costs	Sufficient information has been provided in the spreadsheet.
9	should this model be progressed, how much transparency on the inputs and assumptions is required to understand the numbers	The calculation of the access cost should be transparent. It should involve the breakdown of different augmentations and the NPV calculation of each expansion.
10	how frequently should the inputs and assumptions into the model be reviewed	The inputs and assumptions should be reviewed annually. As the LRIC calculation has a direct impact on generators, the generators should be involved in the review process.

6 References

[1] AEMC, “Supplementary Report: Pricing, Optional Firm Access, Design and Testing”, 31 October 2014.

[2] AEMC, “First Interim Report, Optional Firm Access, Design and Testing”, 24 July 2014.

[3] AEMO, “National Transmission Network Development Plan”, 12 December 2013.

[4] TransGrid, “New South Wales Transmission Annual Planning Report 2013”, June 2013.

[5] AEMO, “National Electricity Forecasting Report 2013”.

[6] EMCa, “Review of Prototype Firm Access Pricing Model”, October 2014.

[7] AEMO, “Treatment of loss factors in the National Electricity Market”, 1 July 2012.

[8] AEMC, “Pricing prototype program: user guide”, October 2014.

[9] AEMO, “Final pricing methodology for prescribed shared transmission services for 1 July 2014 to 30 June 2019”, 28 March 2014.

[10] AEMC, “Transmission Framework Review, Final Report”, 11 April 2013.

Appendix A – Input data for the 3-bus example

Aemc-access.csv:

```
name,MW,node,firm,start,end
Eildon Power Station,100,3EPS220,100,2011,2060
```

Aemc-demand-forecast.csv:

```
load node,net
node,volts,poe,2013,2014,2015,2016,2017,2018,2019,2020,2021,2022,2023
3THO220,3THO220,kV,10% POE,0,0,0,0,0,0,0,0,0,0,0
```

Aemc-lines.csv:

name,from name,to name,admit,cts rating,st rating,type,size,length,dupe,region,from voltage,to voltage,stype,ckt

3EPS220_3THO220,3EPS220,3THO220,5.0,120.0,120.0,L,M,100,1,VIC,220,220,M,1

3EPS220_3SOU220,3EPS220,3SOU220,20.0,250.0,250.0,L,M,50,1,VIC,220,220,M,1

3THO220_3SOU220,3THO220,3SOU220,10.0,125.0,125.0,L,M,50,1,VIC,220,220,M,1

3THO220_3SOU220,3THO220,3SOU220,10.0,125.0,125.0,L,M,50,1,VIC,220,220,M,2

(Note: the two lines 2-3a and 2-3b are entered as circuit 1 and 2 separately. This will force the program to realise there are two lines in parallel.)

Aemc-nodes.csv:

```
name,zone
3THO220,mel
3EPS220,mel
3SOU220,mel
```

Aemc-zones.csv:

ode,zone,percent of zone

3EPS220,mel,0.056285178

Linetypes.csv:

```
type,from_voltage,to_voltage,size,lumpiness,cost,
L,220,220,M,200,500,
```

Zone_growth.csv

```
zone,reference,st_growth,lt_growth
Melbourne,mel,1,1
```

Setting.txt

(No change)