Transmission Pricing Methodology – Better Outcomes for Customers

BETTER OUTCOMES FOR CUSTOMERS
TRANSMISSION PRICING METHODOLOGY

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1. Introduction and overview

This paper is submitted to the AER to explain and support TransGrid's proposed transmission pricing methodology for the period from 1 July 2015 to 30 June 2019.

TransGrid considers that its proposed pricing methodology is consistent with the National Electricity Rules and the AER's pricing methodology guidelines, dated October 2007. A compliance checklist, which demonstrates that TransGrid's proposed pricing methodology complies with these requirements, is provided separately.

TransGrid has consulted its customers and other stakeholders on the transmission pricing methodology that should apply from 1 July 2015. Details of the consultation process, including the papers prepared by TransGrid and submissions received are available on TransGrid's "Have Your Say" website.[1]

A number of common themes were conveyed by stakeholders' written submissions and in face-to-face meetings:

- All respondents commented that TransGrid's current pricing arrangements result in charges that are not sufficiently cost reflective.
- The current 50% proportion of transmission use of system (TUOS) costs that are postage stamped is too high.
- The current methodology misallocates asset costs between customers and/or leads to cross subsidies between customer groups.
- Transmission pricing should be primarily or entirely demand based, rather than energy based.
- TransGrid should be able to provide customers with pricing certainty.

In parallel with the stakeholder consultation activities, TransGrid conducted its own assessment of the current pricing methodology and the options for change. TransGrid shared its views with stakeholders in its 'Provisional Views' paper, which was published on TransGrid's website in February 2014.

With one exception, TransGrid agrees with the concerns raised by stakeholders. The exception relates to the percentage of TransGrid's costs that are fixed, and whether the current 50% of TUOS costs which are recovered on a non-locational (postage stamp) basis is too high. TransGrid's analysis, which was presented in section 3 of the Provisional Views paper, suggests that it is difficult to establish a persuasive case for moving away from the current 50% allocation.

[1] http://www.yoursaytransgrid.com.au/projects/pricing-consultation

TransGrid's proposed pricing methodology sets out 6 changes, as follows:

1. Increased flexibility is provided to:
    a. enable amendment of the pricing methodology following a Rule change; and
    b. introduce the modified CRNP methodology where this approach is likely to result in prices that are more cost reflective.
2. Locational pricing is to be more focused on peak demand by applying the CRNP methodology during a 20 day peak period, rather than 12 months. Locational prices will continue to be applied to maximum monthly demand in the year ahead.
3. All postage stamp prices will be set according to maximum demand, and therefore will no longer apply on an energy basis.
4. The annual change in transmission costs for any TransGrid customer, or large distribution customer, will be capped at a maximum of CPI + 3%. The cap will compare the transmission charges in the most recent financial year with charges in the forthcoming year, assuming that the customer's demand is unchanged.
5. Arrangements are proposed to enable TransGrid to provide pricing certainty for customers including distributors.
6. Excess demand charges will be set on a cost reflective basis.

These proposed changes address the issues raised by stakeholders in TransGrid's consultation exercise. In aggregate, the changes are relatively modest improvements to the current methodology, which are consistent with the Rules provisions and the AER's pricing guidelines. The remainder of this paper explains the rationale for each change.

In addition, as explained in further detail in Appendix A, TransGrid's consultation process has identified a number of more fundamental questions regarding the efficiency of the current transmission pricing arrangements. It is unclear at this stage whether these issues warrant a change to the current Rules, noting that any change to the Rules must be justified in terms of promoting the achievement of the National Electricity Objective.

In considering the case for change, TransGrid is also mindful of the importance of a common approach to transmission pricing across the TNSPs. Therefore, any proposal for change must be assessed in this broader context, noting that operational considerations differ across TNSPs, and these differences may have implications for the optimal pricing arrangements.

2. Increased flexibility in the application of the pricing methodology

At present the pricing methodology is fixed for the duration of the regulatory control period.

A minor exception applies in 2015, as a recent Rule change made by the AEMC will introduce inter-regional transmission pricing and require TNSPs to amend their pricing methodologies by 27 February 2015. TransGrid's proposed pricing methodology will be updated to reflect these changes, as explained in further detail in section 7.

The recent AEMC Rule change raises a broader question – how much flexibility should a TNSP be afforded to amend or update its pricing methodology? TransGrid's consultation process with customers has identified a number of concerns with the existing pricing methodology. In TransGrid's view, these concerns have been exacerbated by the current prohibition on making changes to the methodology during the regulatory control period.

TransGrid considers that two changes should be made in the proposed methodology to provide for greater flexibility. We discuss each in turn below.

2.1 Flexibility to amend the pricing methodology following a Rule change

TransGrid's preference for greater flexibility reflects, in part, the possibility that the company may lodge a Rule change proposal later this year. The details of any Rule change proposal need to be developed further. However, Appendix A sets out in broad terms the rationale for change.

If TransGrid lodges a Rule change proposal and it is accepted by the AEMC, it would not be appropriate for the current proposed methodology to remain in place until 1 July 2019. More broadly, if other Rule changes are introduced that affect the pricing arrangements, TransGrid should have the option of modifying its pricing methodology to accommodate any such Rule changes.

2.2 Flexibility to introduce modified CRNP

The benefit of applying modified CRNP is that it allows prices to reflect the level of network utilisation. In the absence of this adjustment, locational prices may fall as the network becomes more heavily loaded, while prices will tend to be higher for more lightly utilised assets. In effect, the price signal may be inappropriate.

TransGrid has not applied the modified CRNP methodology thus far. Implementing the methodology requires additional inputs to the T-PRICE software to incorporate information on network utilisation. TransGrid has not yet completed this further work, so it would be premature to commit now to the adoption of modified CRNP.

However, TransGrid considers that its pricing methodology should be sufficiently flexible to allow modified CRNP to be adopted during the regulatory period if this approach is expected to provide more cost reflective price signals. Prior to adopting modified CRNP, TransGrid will consult with its customers and explain the rationale for the change. Specifically, TransGrid will:

- advise customers prior to the publication of its prices that it intends to apply the modified CRNP approach;
- update this paper to explain TransGrid's decision to adopt the modified CRNP approach; and
- modify the pricing methodology to reflect TransGrid's amended approach.

2.3 Conclusion

For the reasons set out above, TransGrid's proposed pricing methodology allows additional flexibility compared to the current methodology. In TransGrid's view, this flexibility is consistent with the Rules requirements and the AER's transmission pricing guidelines. Most importantly, TransGrid considers that allowing this flexibility will facilitate improved price signals, which will promote the achievement of the National Electricity Objective, and deliver better outcomes for customers.

3. Locational pricing to be more focused on peak demand

3.1 Cost allocation to be based on 20 highest system peak days

Stakeholders were unanimous in commenting that transmission prices should be more "cost reflective". In broad terms, stakeholders argued that the transmission network must be sized to meet system peak demand. In relation to setting locational prices, therefore, stakeholders considered that the CRNP methodology should allocate costs according to connection point demands at the time of system peak.

TransGrid has considered stakeholders' views in light of the requirements of the Rules, which provide that in applying the CRNP methodology to set locational prices, the modelling should have regard to:[2]

> "…the conditions that result in most stress on the transmission network and for which network investment may be contemplated."

TransGrid currently applies the T-PRICE software over a 12 month period (referred to as an 'element peak approach') to determine the locational costs that are to be recovered at each connection point. This approach captures the maximum extent to which a connection point uses network assets over the course of a year, taking into account the full range of system conditions and generation patterns.

An alternative to the element peak approach is to apply the T-PRICE software to determine network usage during system peak periods only, as proposed by stakeholders. In effect, this approach would not attribute locational costs to connection points for use of the network during the non-system peak periods.

AEMO, in its role as TNSP in Victoria, is the only TNSP in Australia that currently applies the peak pricing CRNP method, by employing:[3]

> "Load and generation data for the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during the most recent 12 months."

TransGrid notes that allocating locational costs according to network usage on the 10 weekdays with highest system demand is likely to be an imperfect method for setting cost reflective prices. This is because local network assets may be most heavily utilised outside the defined peak period, and therefore the driver for new investment may be unrelated to system peak demand. TransGrid is also aware that modelling issues have been encountered by other TNSPs in applying this approach.

The AEMC discussed the choice of CRNP modelling approaches in its determination on inter-regional TUOS charging:[4]

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[2] Clause S6A.3.2(3).
[3] AEMO, Proposed Pricing Methodology for Prescribed Shared Transmission Services, 21 February 2014, page 10.
[4] AEMC, National Electricity Amendment (Inter-regional transmission charging) Rule 2013, 28 February 2014, page 25.

> "The Commission was also required to make a decision on what measure of peak utilisation to incorporate in the inter-regional pricing methodology. A measure based on system peaks has intuitive appeal, because it is usually at times of peak system demand that congestion occurs on the network, and congestion is an important driver of investment in the shared network. The Commission considers an element peak approach has a number of advantages over system peak approach however:
>
> - it is less arbitrary than the system peak method, because there is no requirement to choose peak days for allocating costs, and thus inadvertently choosing winners and losers on the basis of the days chosen;
> - it takes into account a much broader range of operating conditions for which investment in networks is typically considered. It is consequently more consistent with the drivers for network investment; and
> - consumers may find it easier to respond to a charge based on element peak utilisation which is more closely related to their own peak demand relative to a charge which is based on their contribution to system peak demand (consumers can predict their own behaviour better than collective system behaviour)."

TransGrid concurs with the AEMC's observations, and we note that the choice between the two approaches is not straightforward. It is important to reiterate that the overriding objective is to provide cost reflective price signals to customers. For some connection points, this may be achieved by allocating costs according to the demand at times of system peak. At other connection points, the network element approach may provide more efficient price signals if costs are driven by local system conditions. In practice, therefore, each method is likely to prove more efficient in some locations, and less efficient in others.

In deciding on the most appropriate modelling approach, TransGrid is mindful that its consultation process has highlighted that customers want to understand the derivation of their locational prices. To provide customers with confidence that locational prices are appropriate, TransGrid considers that the pricing method must be intuitive, understandable and transparent. In these particular respects, the network element approach to cost allocation is likely to be inferior because the modelling outputs are not easily explained to customers. In other respects, as noted by the AEMC, the network element approach is to be preferred.

In TransGrid's consultation process, stakeholders expressed a strong preference that CRNP should be applied over the 10 day peak period. However, the concern with a focused period of analysis is that it may not identify all the operating conditions under which the network is stressed. This concern is exacerbated if the analysis is confined only to the 10 peak half hours during the year. Based on the NSW load duration curve, TransGrid considers that applying the T-PRICE software over the 20 days with the highest peak demand will capture the vast majority of periods when the network is most stressed. TransGrid considers that this approach will address the issues raised by stakeholders while also ameliorating some of the AEMC's concerns in moving away from the network element approach.

As explained in Appendix A, TransGrid considers that broader questions arise as to whether the transmission pricing signals can be sharpened so that customers are able to respond on a real-time basis to emerging network issues. Before such an approach could be implemented, significant work would be required to demonstrate that the outcomes are likely to be superior to the current methodology. Nevertheless, TransGrid regards the 20 peak day approach as a first step towards developing sharper pricing signals and encouraging demand side engagement.

In terms of price impacts, TransGrid notes that locational prices are subject to a side constraint that limits locational price changes to the average +/- 2 percentage points. This side constraint ameliorates the pricing impacts of any modelling issues that may arise from the proposed change.

TransGrid also notes that the AEMC's determination on inter-regional TUOS arrangements allows for TNSPs to adopt different approaches to CRNP for the purpose of intra-regional TUOS. TransGrid's proposed approach does not, therefore, have any implications for intra-regional TUOS pricing for other TNSPs.

3.2 Calculation and application of locational prices to remain unchanged

Once the locational costs have been allocated, locational prices (expressed in terms of $ per monthly maximum demand) will be calculated using the most recent financial year's demand data.

Once prices are established, they will be applied in the forthcoming year on a prospective basis. Specifically, the transmission charges will be determined by applying the price to the maximum monthly demand at each connection point, in accordance with the current methodology.

TransGrid also proposes that prices should be levied on the basis of MVA. The introduction of this charging arrangement no sooner than 1 July 2017 will provide an appropriate preparation period to install the necessary metering. This charging approach will further improve cost reflectivity and enable distributors to pass through transmission prices more readily to their customers.

Section 3.3 below provides a further explanation of the rationale for TransGrid's approach to calculating and applying locational prices, in light of the AER's recent consideration of AEMO's pricing methodology.

3.3 Further comments on AEMO's methodology for locational pricing

AEMO's pricing methodology sets out the following arrangements for locational pricing:[5]

> "If using the historical data basis to calculate locational prices AEMO will use the average of the transmission customer's half-hourly maximum demand recorded at a connection point on the 10 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. AEMO will consider the most recent 12 month period to be 1 March to 28 February.
>
> The lower of CAMD and t-1 maximum demand will be used in the calculation of the locational price.
>
> To calculate the locational charge for each connection point, the locational price is then multiplied by lower of the average maximum demand for the most recently completed 12 month period (t-1) and the CAMD (if the customer has elected to use a CAMD) at that connection point."

[5] AEMO, Proposed Pricing Methodology for Prescribed Shared Transmission Services, 21 February 2014, page 6.

As already noted, in contrast to AEMO's approach, TransGrid is proposing to apply the T-PRICE software over the 20 peak days in order to allocate locational costs to connection points. There are two further important differences between TransGrid's proposed approach and AEMO's, in terms of the calculation of the price, and the subsequent application of the price to determine the locational charge:

- To calculate locational prices, TransGrid will use the most recent financial year's demand data, rather than the 12 month period from 1 March to 28 February as proposed by AEMO. TransGrid notes that AEMO's timeframe allows insufficient time to calculate the modified load export charge, which must be published annually by 15 March.
- In terms of the application of locational prices, TransGrid proposes to retain its current charging method, under which the $ per monthly maximum demand price is applied on the basis of demand in the forthcoming year. In contrast, AEMO's price is charged on a retrospective basis, according to last year's demand. TransGrid's view is that price signals are only effective if customers are able to respond to those signals. For that reason, TransGrid prefers to retain its existing pricing and charging approach.

4. Postage stamp prices to be based on maximum demand

At present, the Rules require non-locational TUOS and common services to be recovered on a "postage stamp" basis, which does not vary by location.

The Rules define "postage stamp" pricing as:

> "A system of charging Network Users for transmission service or distribution service in which the price per unit is the same regardless of how much energy is used by the Network User or the location in the transmission network or distribution network of the Network User."

Clause 6A.25.2(c) of the Rules states that the selection of the postage stamp pricing arrangement must have regard to:

1. the desirability of a consistent approach across the national electricity market (NEM), particularly for Transmission Customers that have operations in multiple participating jurisdictions; and
2. the desirability of signalling to actual and potential Transmission Network Users efficient investment decisions and network utilisation decisions.

Currently, all TNSPs adopt postage stamp prices based on consumption at connection points with reference to:

- historical energy ($/MWh); and
- contract agreed maximum demand ($/MW).

Either charging arrangement could be regarded as equitable for the following reasons:

- larger customers will make a greater contribution to the recovery of fixed costs; and
- transmission charges will tend to reflect the customers' ability to pay.

During our consultation process, a number of stakeholders questioned whether it is appropriate to recover transmission costs on the basis of energy throughput. These stakeholders submitted that transmission costs are driven by peak demand, not energy consumption, and therefore a pricing arrangement that is based on energy is inappropriate. One submission argued that as the total size and costs of the network have been caused by demand at peak times (albeit some years ago), it is appropriate to recover total costs through prices levied on peak demand.

TransGrid recognises the intuitive appeal of the points raised by stakeholders, and therefore will adopt a maximum demand charging basis, or contract maximum demand as the case may be. This approach is consistent with the Pricing Methodology Guidelines issued by the AER,[6] which set out the following permissible postage stamp pricing structures:

[6] Pursuant to clause 6A.25.2(c) of the Rules.

1. either contract agreed maximum demand or historical energy;
2. maximum demand; or
3. an alternative pricing structure proposed by the TNSP.[7]

The NSW distributors have expressed support for a maximum demand pricing based on MVA, rather than MW. This pricing mechanism would enable distributors to pass through transmission prices to distribution customers more readily and provide a price signal to customers to maintain or improve their power factor. As already noted, TransGrid proposes that prices should be levied on the basis of MVA no sooner than 1 July 2017, which allows a sufficient preparation period to install the necessary metering.

Converting the current mix of energy and demand based prices to a maximum demand basis will not affect TransGrid's total revenue. Our modelling suggests that directly connected transmission customers and distribution companies will not face significant increases in charges, although cost increases at some connection points will be significant.

TransGrid is conscious of the need to ensure that its pricing methodology does not lead to price shocks for any particular customer, including distribution customers. For this reason, TransGrid will apply a CPI + 3% constraint to annual increases in transmission costs to its customers and large distribution customers, where the calculation of the cap assumes that demand is unchanged from the most recent year.

Network charges to customers connected to the distribution network are the responsibility of the relevant distributor, not TransGrid. However, TransGrid recognises that its transmission charges are passed through to a number of large distribution customers. TransGrid intends to liaise with each distributor to extend the application of the CPI + 3% cap to these distribution customers on an annual basis.

The price constraints described above are transitional measures to assist customers with the significant price changes that may occur in some cases as a result of the new pricing methodology. As such, TransGrid should not be adversely affected by the application of these constraints.

To give effect to the price cap, the postage stamp charge will be reduced at the relevant connection point(s) on a transitional basis, and a compensating increase will apply at the remaining connection points. An alternative approach would be to recover the shortfall through the locational charge, but TransGrid regards this option as less desirable.

TransGrid recognises that the application of the proposed side constraint is unprecedented and will raise a number of implementation issues. TransGrid's proposed pricing methodology assumes that these implementation issues can be resolved with the assistance of the AER and distribution companies through the forthcoming consultation process.

[7] AER, Electricity Transmission Network Service Providers - Pricing Methodology Guidelines, October 2007, clause 2.3(b).

5. Price certainty for customers

During the consultation process, a number of large customers expressed concern that TransGrid's current pricing methodology cannot provide adequate price certainty. This sets transmission services apart from other input costs, and makes business planning more difficult for our customers.

TransGrid agrees that customers should be able to enter into agreements to secure greater certainty over their transmission charges. TransGrid therefore proposes that it should be able to negotiate a fixed price with its customers for a period of up to 5 years, being the duration of the relevant revenue cap. TransGrid considers that negotiating a fixed price beyond the period covered by an existing revenue cap would potentially expose all customers to an unacceptable risk of forecasting error.

TransGrid will consult with customers and other stakeholders to develop a framework for negotiating fixed price contracts with customers. The principles that will govern this framework are:

- the negotiated price must reflect a reasonable forecast of the prices that would result from the annual application of the pricing methodology;
- consideration should be given to the value obtained by the customer in securing price certainty;
- the negotiated price should not disadvantage other customers
- the methodology for determining the fixed price should be transparent to all customers; and
- TransGrid should not obtain any benefit or incur any cost as a result of providing price certainty.

This framework would apply to all customers, including distribution network companies.

A key issue in providing price certainty to some customers is its potential impact on prices for other customers if the assumptions adopted prove to be materially wrong (for example, due to errors in forecasting inter-regional settlements residue). It is this concern regarding pricing impacts on different groups of customers that makes it essential to consult with stakeholders in the development of a framework for negotiating fixed prices, and to apply that framework transparently.

6. Excess demand charges to be cost reflective

For those customers who have chosen to have their non-locational TUOS and common service charges set on the basis of contract agreed maximum demand, TransGrid calculates an excess demand charge that will apply if the nominated demand is exceeded.

To date, only two customers have taken up this option.

A number of stakeholders raised concerns in relation to TransGrid's excess demand charges. For example, one stakeholder recommended that excess demand charges should be abolished and replaced with cost reflective charges. Another stakeholder commented that if the contract demand is exceeded, and there is no harm, no penalty or premium charge should be applied to the user.

TransGrid acknowledges that the excess demand charge must be cost reflective, and therefore excess demand charges should be set having regard to the likely costs that will be imposed on TransGrid and other network users if the nominated maximum demand is exceeded. These costs will vary by location and by the magnitude and timing of the excess demand.

TransGrid has proposed changes to its pricing methodology to clarify that the excess demand charge should be set on a cost reflective basis.

7. Inter-regional TUOS

As already noted, under a recent Rule change, inter-regional TUOS charging will apply from 1 July 2015.

The AER is required to develop guidelines relating to the implementation of the new Rule by 30 September 2014. As a first step in developing those guidelines, the AER published an Issues Paper explaining that the Rule change requires the calculation of a 'modified' load export charge, which has the following features:[8]

- it does not affect the total revenues transmission companies earn;
- it recovers the cost of locational transmission use of system services only;
- the final rule prescribes a methodology for allocating costs for the recovery of the load export charge which must be applied consistently across the NEM; and
- the co-ordinating network service providers in each region of the NEM are responsible for calculating, billing and paying the modified load export charge.

Under the new Rule, all TNSPs are required to amend their pricing methodologies by 27 February 2015 to implement the modified export charge from 1 July 2015. In accordance with these requirements TransGrid will amend its proposed pricing methodology after the AER finalises its guidelines in September 2014.

[8] AER, Draft amendments to the AER's transmission Pricing Methodology Guidelines: Inter-regional transmission charge, April 2014, pages 5 and 6.

8. Longer term developments

TransGrid's consultation process indicates that there is further scope for longer term improvements in the current transmission pricing arrangements.

A key question is whether further changes can be made to provide pricing signals that would promote more efficient outcomes for customers.

The discussion in Appendix A examines the shortcomings of the current CRNP methodology and possible future developments in the pricing methodology. Appendix A explains that the changes contemplated would require a Rule change. TransGrid will work with customers and other stakeholders in the coming months to determine whether a Rule change is warranted.

Appendix A: Outline of an alternative pricing method

This Appendix examines the case for developing an alternative pricing methodology.

It comprises two sections:

- Section A1 examines a case study to address the question of whether CRNP is delivering appropriate price signals;
- Section A2 describes an alternative pricing methodology.

A1. Is CRNP delivering appropriate marginal cost price signals?

A key economic objective for a transmission pricing methodology is to provide customers with cost reflective prices so that they can make efficient consumption and investment decisions. In particular, TNSPs may wish to use transmission pricing to:

- influence the magnitude, timing and location of connection of new load; and
- convey to existing users the avoidable costs of increasing their use of the network, particularly when network constraints are emerging.

The purpose of transmission pricing is not to discourage use of the network, but rather to ensure that customers are exposed to prices that reflect the cost of using the network.

However, while the economic objectives for transmission pricing may be easily stated, there are some inherent difficulties that are not easily overcome. For example, in its discussion paper on inter-regional transmission pricing, the AEMC made the following observations in relation to the physical flows on the network:[9]

> "A well functioning market requires the ability of suppliers to identify and charge consumers for the services they provide, or to not supply services to customers who are not willing to pay for them. However, in a transmission network it is not always possible to identify who is consuming a service at a particular time. This is primarily because of the effect of loop flows. Loop flows cause energy flows to split across many parallel paths, including parts of the network some distance away from the primary path, which means that the actions of individual network users can impact other network users."

The CRNP methodology attributes the cost of network assets to particular connection points based on low flow analysis using the T-PRICE software. Inevitably, this process requires a number of assumptions to be made, some of which are embedded in the software. Furthermore, it is not necessarily the case that allocating the costs of existing assets to connection points will deliver appropriate price signals.

[9] AEMC, Discussion Paper, National Electricity Amendment (Inter-regional Transmission Charging) Rule 2011, 25 August 2011, page 34.

A number of questions can be posed to test the economic validity of the transmission prices that result from CRNP (or any alternative pricing methodology). In particular:

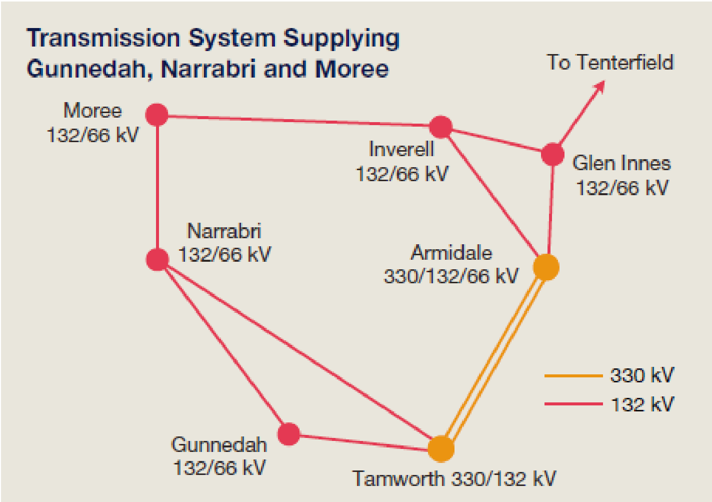
- Are the locational prices reasonably stable over time? As transmission prices are intended to provide long run signals, it is important they are relatively stable.
- Are locational prices the same at connection points that are geographically and electrically similar? A pricing methodology that produces significantly different prices for connection points that share common characteristics would be a cause for concern.
- Do comparatively high transmission prices occur in locations where the TNSP is planning to augment the network? Unless there is a reasonable correlation between price levels and future investment, it is unlikely that the transmission prices will encourage demand responses that may defer investment efficiently.
- Do locational prices reflect the future investment costs? For an appropriate price signal, it should be expected that locational prices have a reasonably close relationship to the costs of new investment. Where investment is expected in the near term, say less than five years, transmission prices should be higher compared to those places where the need for investment is only likely to arise in, say, 10 to 20 years time.
- Do locational prices reflect the current level of network utilisation? To the extent that network utilisation is correlated with a TNSP's future investment plans, then transmission prices should be relatively high when network utilisation is high and spare capacity is in short supply.

Against each of the above criteria, it is an open question as to whether the existing CRNP methodology performs adequately. In relation to stability, as noted in TransGrid's transmission pricing consultation paper, the Rules constrain the price outputs from the CRNP methodology so that they do not change by more than +/-2% of the average. This Rule requirement ensures that locational prices are relatively stable. As discussed below, however, TransGrid's experience is that without this constraint the CRNP methodology would produce substantial variations in prices from year to year at particular connection points.

In relation to the other questions raised above, it is instructive to examine a case study.

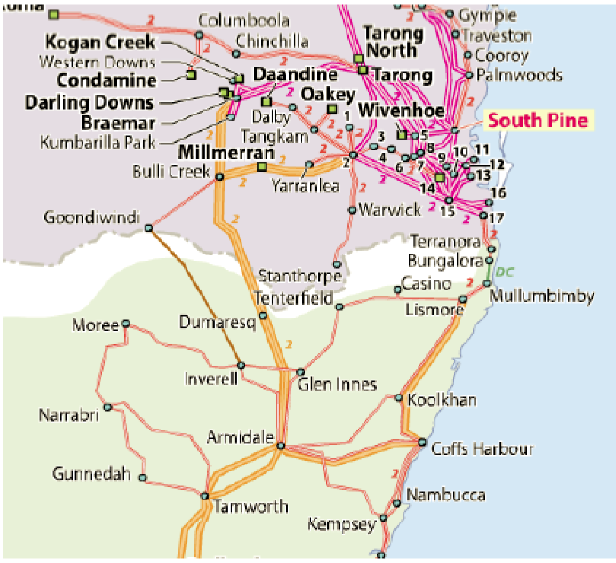
The following case study draws on information published in 2011 in a Project Scoping Consultation Report. Since then demand forecasts have been revised downwards, and it is now considered unlikely that augmentation will be needed in the next five years to supply the Gunnedah, Narrabri and Moree areas. Nonetheless this case study provides useful insights into the appropriateness of the price signals provided by TransGrid's current pricing methodology.

The transmission system supplying the Gunnedah, Narrabri and Moree areas in northern NSW is about 300 kilometres long. The system is shown in the figure below, alongside a table showing the demand charge (locational TUOS) at each connection point in the system.



Connection Point	Demand charge ($/kW/month) for 2013/14
Armidale 66	2.5309
Glen Innes 66	5.0883
Gunnedah 66	4.9545
Inverell	6.0571
Moree 66	9.9673
Narrabri 66	8.2988
Tamworth 66	2.1773

A scale map showing the location of the system is shown below.



The capacity of the system supplying the Gunnedah, Narrabri and Moree areas is limited by thermal constraints on outage of critical 132 kV lines. These limitations presently exist. Expanded mines in the Gunnedah area have been proposed. Should those proceed, the limitations would be exacerbated.

In examining options to address these limitations, the Project Specification Consultation Report (PSCR) published by TransGrid and Country Energy in 2011 explained that:

- The 132 kV network parallels the 330 kV network between Tamworth and Armidale. Consequently power flows within the 132 kV network are affected by flows on the main 330 kV network, particularly inter-state flows on QNI.
- Effectively, some of the inter-state flows pass through the 132 kV network, adding to or reducing (depending on the direction of the inter-state flows) the flows associated with supplying the 132 kV substations within that network. For example, flows from NSW to Queensland increase flows in the 132 kV lines from Tamworth to Gunnedah and Narrabri and reduce flows in the 132 kV lines from Armidale to Inverell and onwards to Moree.

The PSCR also explained that:

- The load of the three substations at Gunnedah, Narrabri and Moree is the main factor affecting flows on the 132 kV lines supplying the area.
- While the load at Inverell does have an impact, it is much less than that of the Gunnedah, Narrabri and Moree loads.
- The approximate effectiveness of load reductions in reducing the limitation (and deferring the need for augmentation) is 100% at Gunnedah, 80% at Narrabri and 60% at Moree.

Options to address the limitations in the system include:

- construction of a 132 kV line from Tamworth to Gunnedah possibly on the route of the recently dismantled 875 Tamworth – Gunnedah 66 kV line;
- construction of a 330 kV line (initially operating at 132 kV) from Tamworth to the Narrabri area;
- construction of a 330 kV line from Dumaresq (to the north of Inverell) to a new 330/132 kV substation near Moree;
- uprating of 132 kV lines in the area; and
- demand management and/or local generation.

Based on the information available at that time, the preferred network option identified in the PSCR was the construction of a new 132 kV line between Tamworth and Gunnedah.

Given the system's characteristics, the nature of the limitations affecting it, and the approximate effectiveness of load reductions in reducing the limitations, it would be reasonable to expect that:

- the locational TUOS charges at Gunnedah should exceed those at, Narrabri; and
- the charges at Narrabri should be higher than those at Moree.

However, as shown in the table above:

- of the three connection points, Gunnedah has the lowest demand charge, while Moree has the highest charge;
- the demand charge at Narrabri ($8.30 per kW per month) is two-thirds higher than that at Gunnedah ($4.95 per kW per month); and
- the demand charge at Moree ($9.97 per kW per month) is double that of the charge at Gunnedah, and 20% higher than that at Narrabri.

In addition, the CRNP methodology produced significant variations in demand charges at these three connection points in recent years. The relative changes in the demand charge at each of these locations over recent years are set out in the table below, which shows the percentage variations in these charges from the previous year before and after the application of the 2% side constraint.

	Unconstrained increase			Increase after 2% constraint		
	2011/12	2012/13	2013/14	2011/12	2012/13	2013/14
Gunnedah	5%	24%	-2%	7%	19%	11%
Moree	1%	21%	-1%	3%	19%	7%
Narrabri	9%	12%	9%	7%	17%	9%

The table shows that for these three connection points, the CRNP methodology produces price signals that vary significantly from year to year. As previously noted, it is reasonable to question whether these variations reflect underlying changes in costs. Indeed, the variability of demand charges from year to year at these three locations, together with the absolute differences between the charges at each location suggest that the present demand charges (derived using the CRNP method) could be improved to provide more cost-reflective signals.

In relation to marginal costs, the PSCR estimated the capital cost of the preferred network option to be approximately $36 million with annual operating and maintenance costs of around 2% of the capital cost. When amortised over the expected aggregate demand increase at Gunnedah, Narrabri and Moree that would be met over the 10-year planning horizon, the estimated avoidable cost[10] of meeting the additional demand is approximately $20.50 per kW per month. This is an estimate of the cost attributable to the demand *increase* over the next 10 years that is causing the need for augmentation.

It is noted that the cost per unit of new capacity would decline if load growth continues to increase over the 50-year life of the new asset. Nonetheless, for the purpose of signalling the additional costs that can be avoided if projected load growth over the next 10 years is curtailed, a cost of around $20 per kW per month would be reasonable.

Ideally, a cost reflective price at Gunnedah, Narrabri and Moree would reflect this signal to marginal load at these connection points.

Under current pricing arrangements, the same demand charge applies to each unit of demand. In accordance with that approach to pricing, if the ten-year avoidable cost is averaged across the total forecast demand at the Gunnedah, Narrabri and Moree connection points over the 10 year horizon, the demand charge would be $2.40 per kW per month. It is noted that this is approximately one-half of the demand charge currently applying at Gunnedah, and roughly a quarter of the charges applying at Moree and Narrabri. However, such an approach to pricing is very likely to under-signal the value of demand growth curtailment.

A further potentially useful reference point in considering the marginal cost of transmission services may be provided by a much more broad-brush estimate of the cost of adding new transmission capacity. Assuming an all-in cost of, say, $1 million per MW of installed transmission capacity (including lines, substations, secondary systems, and operations and maintenance) implies a long-run cost of around $8 per kW per month. This estimate assumes, in effect, that capacity can be installed in small increments - enabling installed capacity to be fully utilised - when in fact it cannot. The strong scale economies in transmission result in new capacity being installed in large increments relative to load growth, and as illustrated in the

[10] The avoidable cost of the 50-year asset over ten years is calculated using annuities.

discussion above, this in turn results in much higher estimates of unit marginal costs over the first 10 years of a new asset's life. Given the uncertainty relating to the utilisation of new capacity over the whole of its life, it would not be unreasonable for usage prices to signal the unit marginal costs over the first 10 years.

A2. An alternative pricing methodology

In light of the case study, it is useful to consider whether an alternative to CRNP could be developed to better reflect TransGrid's future investment plans and provide more appropriate price signals to customers. The previous section raised a number of questions to test the economic validity of the transmission prices that result from CRNP. In summary, the case study found that the locational prices produced by CRNP may not provide:

- reasonably stable price signals over time; or
- consistent prices at connection points that are geographically and electrically similar; or
- prices that reflect TransGrid's future investment plans.

These findings cast doubt on the validity of the CRNP methodology. It is not surprising, however, that the CRNP methodology does not reflect TransGrid's future investment plans. In particular, as the CRNP methodology allocates costs of the existing network to each connection point, it is inherently "backward-looking" in nature.

The CRNP methodology has been applied for a number of years by all TNSPs, and was developed following extensive industry consultation. It is important that any replacement methodology has the confidence of industry and stakeholders, and is capable of producing prices that are robust and defensible. While the price outcomes from the CRNP methodology may be criticised, it is not straightforward to develop a more robust alternative.

In broad terms, there are two options for a better pricing methodology:

1. improve the existing CRNP methodology by addressing its principal shortcomings; or
2. develop a new pricing methodology that does not employ CRNP.

In relation to the first option, a potentially useful step is to adopt "modified CRNP" as this methodology takes into account the existing level of network utilisation in setting locational prices. To the extent that utilisation is a reasonable proxy for forward-looking investment, the modified CRNP methodology is likely to provide better signals regarding TransGrid's future expenditure plans. As already noted, TransGrid's proposed pricing methodology proposes that the modified CRNP methodology should be introduced where this approach is likely to result in prices that are more cost reflective.

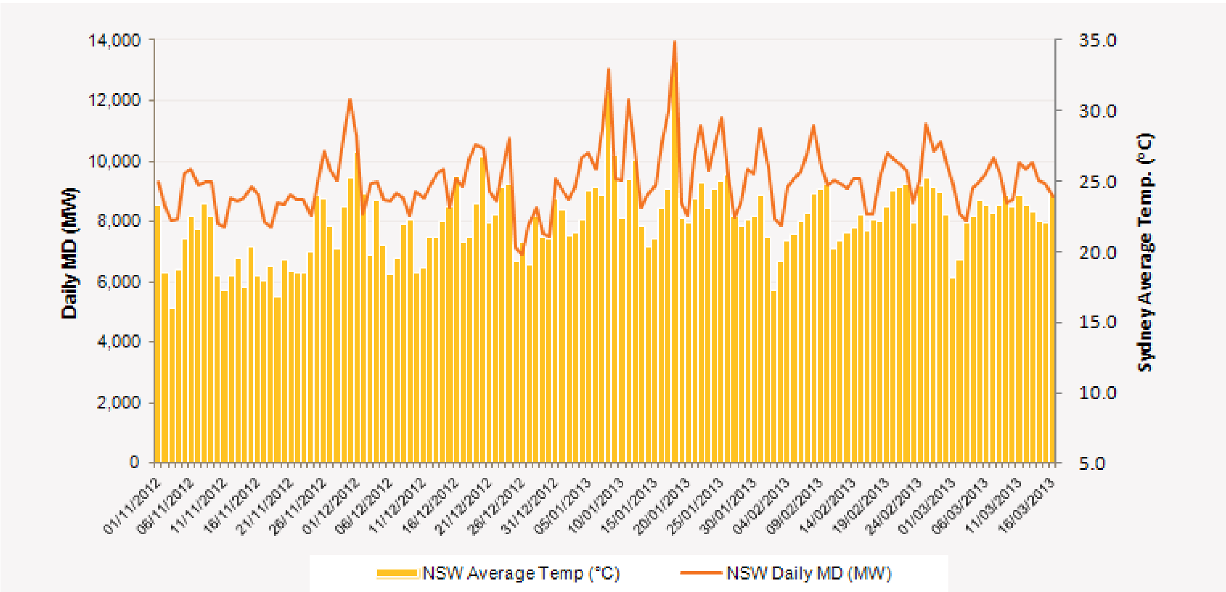
In relation to the second option, a new transmission pricing methodology could be developed to provide price signals at each connection point that reflect TransGrid's forward-looking investment plans. It is likely that the pricing methodology would apply to planned renewal capital expenditure in addition to augmentation capital expenditure, as (some) renewal capital expenditure should be regarded as "avoidable" or variable in nature. The benefit of such an approach is that it would encourage demand-responsiveness at specific connection points, which could lead to the efficient deferral of planned investment.

TransGrid is required to publish details of its future investment plans over a ten-year planning horizon in its Annual Planning Report. In addition, TransGrid publishes its long-term vision for the development of the transmission network. The development of locational transmission prices reflecting future investment requirements could be conducted alongside the consideration of transmission reliability standards, which has recently been the subject of an AEMC review.[11]

As illustrated in the case study, establishing a locational price that provides an appropriate signal is not a straightforward matter. In addition, to provide an effective signal to customers, the prices must be known in advance of the customers' consumption decisions. In broad terms, there are two options for achieving this outcome:

1. posting a tariff which applies during periods when the peak is most likely to occur; or
2. nominating the 'peak pricing days', say, 48 hours in advance.

It is possible to regard these options as being on the same continuum. Specifically, as posted tariffs become more granular, Option 1 transitions to Option 2. In considering the best approach, it is instructive to review the pattern of demand on the NSW system. The chart below shows that in NSW over the summer of 2012 – 2013 there were approximately 26 days when the maximum demand exceeded 10,000 MW, 11 days when it exceeded 11,000 MW, and 4 days when it reached or exceeded 12,000 MW.



If prices could be applied on a prospective basis, it would provide a genuine opportunity for customers to reduce load and, in the long term, reduce the need for future investment. However, such a pricing methodology would be a radical change from the existing arrangements, and a case for adopting this approach would need to be tested thoroughly before proceeding further. For example, 'real time' pricing would significantly complicate the pricing process by requiring TransGrid to provide demand forecast information to customers; estimate the demand response; and manage revenue risk.

A further question arises as to how locational prices would change if investment takes place and reduces the marginal costs of using the network. In theory, it could be argued that as soon as investment occurs, the price signal should be substantially reduced (perhaps to zero) in order to encourage additional load and make use of the available transmission capacity.

[11] AEMC, Review of the National Framework for Transmission Reliability, Final Report, 1 November 2013.

However, such a pricing arrangement lacks intuitive appeal. In TransGrid's view, it is inappropriate for investments to be regarded as 'sunk' immediately on completion, and recovered through postage stamp charges from all customers. Furthermore, if such a pricing approach were adopted customers may reasonably regard the price signal as temporary, as the cost of the new investment would be recovered from the wider customer base, rather than the customers that caused the investment.

It is reasonable to argue that regulated transmission prices should reflect the prices that would exist in a competitive market. In a competitive market, where assets are constructed to serve particular customers or groups of customers, it is appropriate for those costs to be attributed to those customers and recovered accordingly. If, instead, prices were averaged across all customers irrespective of location, the resulting prices would not be sustainable because competing service providers would undercut the average price in those areas where the costs to serve were lower than average. Ultimately, therefore, prices in a competitive market would reflect the local cost to serve.

In light of the above discussion, two points are apparent:

- the marginal cost price signal should reflect the incremental costs to serve customers at a particular connection point, which depends principally on the TNSPs' future investment plans, which in turn will reflect the existing level of asset utilisation; and
- in relation to existing assets, it may be appropriate to recover these (fixed) costs on a locational basis rather than on a postage stamp basis.

Therefore, while the marginal costs of serving a connection point may be substantially lower after the augmentation occurs, the sunk costs will increase. It is appropriate for those sunk costs to be attributed to that connection point, and recovered in a manner that does not distort the marginal cost signal.

It is an open question whether the CRNP methodology is the best tool for allocating the costs of the existing asset base to particular connection points or whether an alternative method could be developed. Notwithstanding this issue, the above approach is significantly different to the current methodology in which the CRNP model is applied to determine the marginal cost signal, and the non-locational costs (which represent the fixed costs) are recovered on a postage stamp basis which does not vary by location. Under the alternative approach described here, CRNP could be used to apportion the recovery of the TNSP's fixed costs in an equitable manner that recognises that the existing costs to serve vary by location.

If the alternative methodology were adopted, one likely consequence is that prices at particular connection points would be significantly different to current prices. In some locations, prices may be unsustainably high. In those circumstances, prices would need to transition to a target price over time, and prudent discounts may need to apply at particular locations to address the risk of uneconomic bypass.

Evidently, a significant number of practical issues arise in the development of a new pricing methodology. For the reasons set out above, the alternative methodology described would be a significant departure from the current approach and would require a Rule change.

TransGrid will work with customers and other stakeholders to consider whether a Rule change proposal for submission to the AEMC should be developed.