Consultation
on
Transmission pricing methodology: issues and proposal.
Second issues paper.

Submission by Electric Power Optimization Centre

The University of Auckland

http://www.epoc.org.nz

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Executive Summary

1. The Second Issues paper proposes a much simplified transmission pricing scheme, consisting of connection charges, Area of Benefit charges, and Residual charges. The incentives created through the modifications to these charges through the use of *optimisation* and prudent discounting need to be carefully considered.

2. The transmission charging regime should endure possible disruptive changes in the electricity industry and incentivise welfare maximizing use of existing transmission facilities, while providing efficient price-signals for investment.

Introduction

1. This report is a submission by the Electric Power Optimization Centre (EPOC) on the working paper Transmission pricing methodology: issues and proposal. The working paper proposes a simplified methodology for transmission pricing and is seeking submissions from stakeholders on this proposal.

2. EPOC is a research group at the University of Auckland that conducts independent research into wholesale electricity markets. EPOC has considerable experience in looking at various transmission pricing methodologies (see e.g., [1,2]). EPOC is also currently analysing an alternate transmission pricing proposal which explicitly prices transmission flows within SPD. Examples based on this proposal are given in Appendix 1.

3. EPOC supports the general principle of beneficiary pays for electricity transmission. The implementation of this needs care to yield an efficient transmission pricing system.

4. The transmission system provides several benefits for electricity consumers. In any trading period the presence of transmission provides:
   a. system reliability;
   b. market competition;
   c. short-run efficient dispatch;
   d. an option to use cheaper power.

   These benefits are quite different in form. Pricing mechanisms to pay for each of these benefits must therefore be different. It is not clear how to combine these to produce an enduring, efficient pricing, mechanism.

5. **System reliability** is a currently treated as a public good. We do not currently have a system in which different agents might pay different prices for different levels of reliability. If this were the case then one might demand different prices of transmission for different customer service levels. Otherwise reliability should be treated as a public good.

6. Transmission enhances **competition** by enlarging the pool of competitors at each location. Competition benefits are very difficult to quantify and depend on counterfactual models of market-power exercise, the outputs of which are sensitive to model assumptions. Thus allocating costs based on estimated benefits of increased competition is open to some litigation.

7. Transmission enhances **efficient dispatch** by enabling remote generating plant that is cheaper than local plant to satisfy demand using the transmission system. The beneficiaries of this dispatch are consumers who receive power at lower prices than those asked by local generating plant.

8. Transmission also has an **option value** for consumers. If a consumer generates all their own electricity, a grid connection provides a backup option that they might use when needed. This option has a value that should be priced in the market.

Proposals within the TPM working paper

9. EPOC notes that, in the latest proposal, the Authority has moved away from peak-based transmission charges, and instead has focussed on volume-based (MWh) and capacity-based (MW) charges. The rationale for this appears to be that the grid has been has recently been expanded.

10. EPOC is of the opinion that the design of this transmission pricing methodology should be enduring, and be able to continue to send the correct price signals in the future, if the grid were to require further upgrades.

11. By designing the TPM based on short-term goals for the efficient utilisation of current grid infrastructure, there is a danger of deleterious long-term effects, such as inefficient investment decisions.

12. **Area-of-benefit Charge**
The Authority has proposed optimising the value of assets. The reason for this optimisation is an over-building of the transmission network, due to incorrect growth forecasts.

> *"Optimisation means that asset values are reduced (i.e., optimised) when they are no longer used to the extent originally envisaged."*

TPM Second Issues Paper (109).

> *"If an asset is optimised, the revenue remaining to be recovered in relation to that asset would be recovered through the residual charge as that charge is not intended to be service-based and is designed to minimise distortions to grid user behaviour."*

TPM Second Issues Paper (111).

The additional residual charges resulting from the optimisation are only apportioned to load users. As the residual charge is increased, this can put more pressure on marginal industries to install distributed generation; which is the opposite effect to what is desired.

The **prudent discount policy** may be used to ensure that the marginal industries stay connected to the grid. However, this will further increase the residual charges on the load, creating a possible domino effect. Moreover, the prudent discount policy puts a short-term emphasis on the efficient utilisation of the current grid, and ignores the adverse long-term consequences of enabling inefficient loads to continue to operate, being subsidised by the rest of the market.

> *"…subject to certain conditions, if transmission charges are a material portion of the customer's input costs, and the customer is materially at risk of closing down its New Zealand plant (and so disconnecting from the grid), having*

> *taken reasonable steps to remain viable as a going concern…"*
>
> TPM Second Issues Paper (130b)

EPOC takes the view that Transpower should be subject to some discipline in making investment decisions. By moving the optimised charges into the residual, Transpower's poor investment choices are obscured and they can continue to return healthy dividends to the Government. However, if Transpower were forced to absorb any losses, it would ensure that there is a level of accountability for the investment decisions.

13. Residual Charges

EPOC contents that the rationale for the residual charge not applying to generation (quoted below) is flawed. The paragraph below states that a charge applied to generators would simply be passed onto load, and could lead to investment and operational distortions. However, if the charge were based on the historical AMI for a generator, this charge would not easily be able to be passed on in a competitive market.

Even if firms were able to pass these costs on to the load, that is no reason to not charge the generators.

> *"The Authority is not proposing to apply the residual charge to generators, for two reasons. The first is that, in general, generators are more sensitive to transmission charges than load, and so a residual charge applied to generation is likely to result in costly distortions to generator investment and operation decisions. The second reason is that a very high proportion of a flat-rate residual charge on all generators, such as a MWh charge, is likely to be passed on to consumers in the form of higher wholesale electricity prices, which means load customers will end up effectively paying the charge anyway."*
>
> TPM Second Issues Paper (116).

14. Moving away from RCPD

The Authority's aim is to move to a durable transmission pricing methodology. However, the paragraph below suggests that the Authority believes that demand will not grow to the point that current lines will need to be expanded. EPOC believes that this view is short-sighted.

If peak charging (such as RCPD) were removed, there will be reduced incentive to manage the utilisation of the lines, meaning the likelihood of congestion will increase. Furthermore, pricing incentives for the location of new loads and generation will be eroded, and could lead to significant efficiency issues into the future.

> *"The Authority has moved away from a peak charge for the residual because a peak charge is efficient only where there are costs that can be avoided by avoiding peaks. Imposing a peak charge on a system where there is no significant new investment to avoid is inefficient because it discourages use*

of the grid when that use would be efficient. The Authority is proposing a capacity-based charge for the residual precisely because it is difficult to avoid—it is less distortionary because it spreads the fixed cost in a way that is unrelated to how much customers use the asset."

TPM Second Issues Paper (D.16).

References

[1] Philpott, A.B. On coincident-peak and anytime-peak transmission charges http://www.epoc.org.nz/papers/PeakCharging.pdf.

[2] Ruddell, K., Philpott, A.B., and Downward, A. Supply function equilibrium with taxed benefits. EPOC working paper, August 2015. www.epoc.org.nz/papers/SFEtaxRPD.pdf.

Appendix 1

Examples of integrating transmission pricing within SPD

Consider a network consisting of two nodes joined by a single transmission line. This line has just been upgraded from 200MW to 400MW capacity. We will explore two scenarios to see how transmission pricing can be incorporated into SPD in order to recover the transmission investment costs from the market participants. In both of these cases: we will have cheap generation (600MW, offered at marginal cost of $20 / MWh) at node A and expensive generation at node B (600MW offered at marginal cost of $50 / MWh); there will be low demand at node A and high demand at node B.

In case 1, we have a demand of 100MW at node A and a demand of 250MW at node B, whereas in case 2, we have a demand of 300MW at node A and a demand of 600MW at node B. We will explore the effect of pricing transmission within SPD on the transmission rentals and the surpluses of the market participants. In order to compute the surplus of the consumers, we set their marginal utility to be $100 / MWh.

We will first compute the values for market prior to the grid upgrade. Then consider three transmission prices for the upgraded portion of the line: $0 /MWh, $10 /MWh, $35 /MWh.

Case 1:

		200MW	400MW		
Transmission Charge		No Charge	No Charge	$ 10 / MWh	$ 35 / MWh
Prices	Node A	$ 20 / MWh	$ 20 / MWh	$ 20 / MWh	$ 20 / MWh
	Node B	$ 50 / MWh	$ 20 / MWh	$ 30 / MWh	$ 50 / MWh
Dispatch	Producer (A)	300 MW	350 MW	350 MW	300 MW
	Producer (B)	50 MW	0 MW	0 MW	50 MW
Transmission	Flow	200 MW	250 MW	250 MW	200 MW
	Rents	$6000	$0	$2500	$6000
Surplus	Producer (A)	$0	$0	$0	$0
	Producer (B)	$0	$0	$0	$0
	Consumer (A)	$8000	$8000	$8000	$8000
	Consumer (B)	$12500	$20000	$17500	$12500
	Total Welfare	$26500	$28000	$28000	$26500

In this case, the demand at node B gains $30 / MWh after the line is upgraded, applying transmission costs to SPD captures $10 / MWh of this benefit towards the cost of the line. The transmission charge could be increased up to $30 / MWh without affecting the efficiency of dispatch. Going beyond this price will lead to underutilisation of the line, as seen in the final column in the table above.

Case 2:

		200MW	400MW		
Transmission Charge		No Charge	No Charge	$ 10 / MWh	$ 35 / MWh
Prices	Node A	$ 20 / MWh	$ 50 / MWh	$ 40 / MWh	$ 20 / MWh
	Node B	$ 50 / MWh	$ 50 / MWh	$ 50 / MWh	$ 50 / MWh
Dispatch	Producer (A)	500 MW	600 MW	600 MW	500 MW
	Producer (B)	400 MW	300 MW	300 MW	400 MW
Transmission	Flow	200 MW	300 MW	300 MW	200 MW
	Rents	$6000	$0	$3000	$6000
Surplus	Producer (A)	$0	$18000	$12000	$0
	Producer (B)	$0	$0	$0	$0
	Consumer (A)	$24000	$15000	$18000	$24000
	Consumer (B)	$30000	$30000	$30000	$30000
	Total Welfare	$60000	$63000	$63000	$60000

In this case, the demand at node A loses $30 / MWh from the upgraded line, and the plant at A gains $30 / MWh, applying transmission costs to SPD captures $10 / MWh of plant A's benefit towards the cost of the line (while also refunding some customers). This price can be increased up to $30 / MWh, at which point the net benefits will accrue to the transmission owner, beyond this price we have an inefficient dispatch, as seen in the final column above.

In the above examples we can see that we are able to recover costs directly from the beneficiaries of the transmission expansion. This is different from the SPD method in that we do not rely on the construction of a counterfactual scenario. Instead it allows the transmission operator to price transmission and it will be utilised if its value is less than its cost.

Formulation

The mathematical formulation for this simple dispatch problem can be written as:

$$
\begin{array}{lll}
\min & 20x_A + 50x_B + T|f_2| & \\
\text{s.t.} & x_A - f_1 - f_2 = d_A & [\pi_A] \\
 & x_B + f_1 + f_2 = d_B & [\pi_B] \\
 & 0 \le x_A \le 600 & \\
 & 0 \le x_B \le 600 & \\
 & -200 \le f_1 \le 200 & \\
 & U \le f_2 \le U &
\end{array}
$$

Here x_A and x_B are the dispatch quantities for the two plants; d_A and d_B are the demands are the two nodes; f_1 is the flow on the original line from node A to node B; f_2 is the flow on the upgraded portion of the line ($U = 200$ if upgraded and 0 otherwise); T is the price of sending flow in either direction on the upgraded portion of the line; and π_A and π_B are the nodal prices.