Consultation
on
Transmission Pricing Methodology Review
TPM Options

Submission by Electric Power Optimization Centre

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http://www.epoc.org.nz

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Executive Summary

1. The TPM Options working paper contains a number of options for charging for transmission services. The options are a mixture of postage stamp charges, maximum demand charges, and flow-based beneficiary-pays or user-pays charges. The working paper seeks feedback on the best choice or combination of these charges to give a workable transmission pricing system.

2. The best mixture of these charges needs to be reconciled with the incentives they produce.

3. EPOC takes the position that the collection of transmission charging options is overly complex, and many of these do not avoid incentives to alter short-run behaviour in the spot market.

4. Any flow-based charges have the potential to distort short-run price signals that come from SPD. These distortions affect deep-connection charges and SDP charges.

5. If short-run price distortions can be overlooked then there are simpler mechanisms to recover some fixed costs from SPD. For example, the transmission owner might charge an increasing tariff for the use of a line as it approaches its thermal capacity.

6. The transmission charging regime should endure possible disruptive changes in the electricity industry and incentivize welfare maximizing use of existing transmission facilities. Flow-based charges risk a situation in which decreasing willingness to pay for transmission leads to stranded assets.

7. EPOC gives an example of an option charge that could replace HAMD to pay for connected capacity (even thought this capacity might not be used).

8. SPD charges create incentives to avoid the charge in the short term. These incentives weaken with increased uncertainty in demand shocks. When future demand (and wind generation) is known, suppliers can increase their offers on infra-marginal bids with little risk of not being dispatched at the forecast point. This incentive attenuates when the risk of not being dispatched increases.

9. SPD charges on demand rely on estimates of VoLL. These charges can overestimated if generation plant has become decommissioned due to the addition of transmission capacity.

10. The use the HHI to identify lines for flow tracing creates perverse incentives.

Introduction

1. This report is a submission by the Electric Power Optimization Centre (EPOC) on the working paper Transmission Pricing Methodology Review TPM Options. The working paper proposes several options for transmission pricing and is seeking submissions from stakeholders on these options.

2. EPOC is a research group at the University of Auckland that conducts independent research into wholesale electricity markets.

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.

9. The following sections will examine each of these benefits in turn and comment on the most appropriate pricing mechanisms for these.

The future of electricity generation

10. In recent months, much attention has been paid in the media to the emergence of disruptive technologies and models for electricity generation. Of course, the future of these new technologies is uncertain, and predictions are bound to be wrong. It is clear that at least for industries that require large volumes of electricity, the economies of scale of conventional electricity generation will enable these to persist for some time. Nevertheless, one might see increasing numbers of consumers becoming less reliant on transmission.

11. If a consumer becomes less reliant on the transmission grid, then he or she will be less willing to pay for this. If the payment is based solely on the energy used by a consumer, then the consumer who uses no energy at all would pay nothing. EPOC believes that such a pricing mechanism could produce unintended and undesirable outcomes.

12. An optimal social plan for New Zealand generation currently delivers electricity from large scale renewable generation plant through an existing transmission grid. If consumers with embedded generation do not contribute to the transmission grid then the costs of this will be borne by the remaining consumers. If consumers are charged by energy use then the benefits of reducing energy consumption from the grid will increase at the margin as more consumers rely on embedded generation. A doomsday scenario for the grid might predict a tipping point beyond which the electricity grid becomes an unsustainable stranded asset, when it is priced so high that no user will gain a net benefit.

13. For these reasons, EPOC takes the position that pricing mechanisms for the transmission grid should be carefully constructed to reflect the total value to consumers that the grid represents. The benefits of cheaper energy are zero if the short-run marginal cost of local generation (from solar and wind) is also zero. The benefits in this setting come from the certainty of the availability of grid power, i.e. the option value.

System reliability benefits

14. The transmission system provides increased reliability. If a local generation plant experiences a unit failure, the grid provides backup generation to ensure a continuous and reliable supply.

15. Short-term reliability is currently provided through the grid by the instantaneous reserve market that is dispatched with energy through SPD. The short-run cost of instantaneous reserve is therefore paid by the load. The ability to transport this reserve through the transmission system to deal with an event is not priced in the market. Although the difference in time scales is really a continuum, we choose to distinguish this short-term spinning reserve from energy backup, for example grid power replacing intermittent off-grid generation.

16. Ideally electrical energy should be a product differentiated by different levels of reliability. Consumers would pay different prices for different qualities of service. Pricing models for service quality are well established in other sectors (e.g. airlines, internet) and are being discussed in some electricity markets overseas (Doorman, 1975, Margellos and Oren, 2015). EPOC believes that a transmission pricing methodology should be capable of including such pricing models, even if they are difficult to implement in the short term.

Competition benefits

17. Electricity transmission enhances competition between generators in different locations. The Electricity Commission's Grid Investment Test allowed these benefits to be included in a cost-benefit analysis if they could be quantified. However quantifying these is very difficult, as they depend on counterfactual estimates of efficiency losses from exercise of market power. Although EPOC continues to develop models that provide some benchmarks for these values, any mechanism that allocates the cost of transmission based on the savings from a model of imperfect competition is likely to be open to litigation. So we do not propose this as a realistic pricing mechanism.

Cheaper energy

18. The main value of the transmission grid comes from its ability to transport energy from inexpensive generation to remote demand. Given a transmission grid, values of electricity demand, and short-run marginal cost offers from generators, the most efficient dispatch of electricity generation in the short run is provided by a social plan (computed by SPD) that minimizes the short-run electricity generation cost. This model assumes that generator capacities and transmission capacities are given, and do not change.

19. Capacity expansion of generating plant can be viewed through the lens of SPD. Under the assumption of perfect competition, the theory is as follows. Generation is offered at short-run marginal cost, and generators earn infra-marginal rents from uniform prices. The rents from a peaking plant are earned during shortage periods when prices are set at the price cap. These happen very rarely but often enough to cover the fixed cost of the last peaking plant built. The frequency of shortage (typically set by a regulator) then determines the price cap to ensure capacity choices are optimal in equilibrium.

20. In practice, capacity expansion is lumpy, generators are risk-averse, and regulators are unwilling to set high price caps. As a result, the settings make it difficult for generators to make enough risk-adjusted profit in a competitive setting to yield socially-optimal capacity choices. The choice facing a regulator is then between a capacity market (for example, PJM) or a "workably competitive" energy-only market (such as New Zealand) where risk-adjusted profits are earned by bidding above short-run marginal cost.

21. Various energy-only capacity expansion models have been proposed in the literature. The simplest model (Hogan, 2005) imposes a reserve margin on generation whereby the electricity price hits the price cap whenever the reserve margin is violated by a dispatch. This means that there is enough generation capacity to meet load without shedding, but prices go to the cap before this occurs.

22. In a perfectly competitive setting, transmission can be priced at the margin using SPD. When a transmission line becomes constrained it generates a rental (from the shadow price, typically equal to the difference in nodal prices at each end of the line). If this price then exceeds the per-period cost of a MW expansion in line capacity then it is welfare enhancing at the margin to expand the line, otherwise it is not.

23. In practice, transmission rentals are insufficient to pay for the cost of the line for several reasons. First, since a transmission line has value over and above the energy savings it enables, it might be rational to build a line even though transmission rentals are insufficient to pay for it. Second, transmission investment is lumpy, so rentals are not accrued continuously like they would be in an optimal incremental expansion plan. Finally, transmission is constructed in advance of the economic need for it, so the accrual of rentals may be less frequent than needed to pay for the transmission investment.

24. In a similar way to generation capacity, transmission can be valued using a reserve margin. This involves transmission capacity being de-rated in pricing runs of SPD, and rentals accruing when reserve margins are violated. The most effective method of doing this in SPD is for the system operators to add a transmission charge for transmission that violates the reserve margin. This charge will add to the marginal cost of remote generation and change the nodal price that consumers pay.

25. We acknowledge that charging for the use of transmission as it approaches capacity will distort short-run pricing signals. In the short run, it is inefficient if existing capacity is not fully utilized when its short-run marginal cost is zero. (We remark that a similar distortion might occur when generators offer at long-run marginal cost.) Furthermore, any beneficiaries pay pricing scheme will lead to some level of inefficiency, and firms could change their behaviour to reduce the charge. This method, however, is significantly simpler to implement and much more transparent.

26. We believe that this transmission reserve margin method should be designed to recover only a portion of the costs of the line investment – those attributable to the beneficiaries of the line (in the energy market). If the transmission asset delivers benefits that exceed the costs needing to be recovered, it should be possible to price the use of asset within SPD in such a way that the costs will be recovered without changing the short-run dispatch efficiency. Moreover, the nodal pricing will better reflect the LRMC of transmission, and potentially provide more appropriate pricing signals. We provide some examples in Appendix 2 to illustrate how transmission prices might be introduced into SPD, and the implications of the distortion to short-run pricing signals.

Option value

27. The option value of transmission needs to be paid for by those benefiting from the option. The option can be valued by examining the size of transformer that a purchaser might install at their grid exit point if these could be chosen to take any value. The size of the transformer chosen effectively limits them from taking any more electricity off the grid.

28. In practice it is not possible to choose any size of transformer, as these come in discrete sizes. An ex-post proxy for this size is the anytime maximum demand. Alternatively, electricity purchasers or aggregated electricity purchasers could bid ex-ante for a maximum offtake. For example a lines company could submit a demand function for capacity in which the price per unit of additional capacity decreases as the capacity sought becomes larger. Similar markets for capacity are proposed in (Doorman, 2005) and (Margellos and Oren, 2015).

29. Given demand curves for capacity in each trading period, the transmission system operator can choose transmission line capacities, so that demand for capacity in every trading period can be satisfied using grid transmission. This becomes an auction of call options to consumers, the proceeds of which are aggregated to pay for the option value of the grid. Since the options that are sold must be matched by supplier capacity, generators are paid (a reservation price) for ensuring capacity is available. A toy example of such a dispatch system is illustrated in Appendix 1.

The SPD Charge

30. The Electricity Authority has proposed a beneficiary pays scheme for allocating costs of transmission assets. This entails the estimation of the benefits of an asset accruing to different agents by running the dispatch software (SPD) both with and without the asset. Requiring beneficiaries to contribute to the cost of these assets will have an effect on short-run behaviour.

31. A previous submission by EPOC (Downward et al, 2012) provided some analysis of the incentives provided by imposing taxes on supplier profits. This analysis has been improved in the companion paper (Downward et al, 2015).

32. The SPD charge has the effect of introducing a measure of pay-as-bid pricing to dispatch levels where the new capacity of a transmission asset is in use. We have used supply function equilibrium models to examine how generators with market power respond to a charge like SPD. See (Downward, Philpott, Ruddell 2015).

33. Depending on some parameters of the beneficiaries-pay scheme and the distribution of demand, there are two sorts of market equilibrium – a pure-strategy equilibrium with modest additional mark-ups and a mixed-strategy equilibrium with significant mark-ups and increased volatility in prices. Besides the strategic response, we find inaccuracies in the way the SPD charge accounts for benefits from transmission assets that form part of a transmission network and also raise concerns about the *ad hoc* nature of the charge as load and generation patterns shift in the longer term.

The SPD charge distorts the real-time wholesale market

34. In our working paper (Downward, Philpott, Ruddell 2015) we model the SPD charge in a market where all firms are price-takers. When there is no SPD charge, price-taking generators will offer all generation at short-run marginal cost. When the SPD charge is applied there is an incentive for generators to mark up their bids for offer tranches likely to not be dispatched in the counterfactual; this happens even though the generators accept they have no influence on the clearing price.

35. When generators possess market power, the price-taking supply function equilibrium of the previous paragraph provides a lower bound on bids. Therefore we can conclude that even in a workably competitive market the SPD charge will entice generators to mark up their bids in the real-time market, leading to allocative inefficiency and the under-utilisation of transmission assets.

The SPD charge is open to manipulation by strategic bidders

36. In a previous submission (Philpott et al, 2014) we suggested that the market power effects of the SPD charge could be small because uncertainties in load would lead to pure-strategy supply-function equilibria that differed little from

those without transmission charges. This depends on demand being sufficiently close to uniform with a high variance.

37. In the previous model in (Philpott et al, 2014) we also assume that the proportion α of "perceived benefit" charged as a line tariff is small. Pure strategy equilibrium exist only if $\alpha < 0.5$. However, with the proposed monthly capping system this proportion would vary from month to month, and in some months all of the perceived benefit would be taxed, yielding $\alpha = 1$.

38. If either $\alpha > 0.5$ or demand has low variance or differs substantially from a uniform distribution then pure-strategy supply function equilibria do not exist. Here there is a strong incentive for strategic generators to mark up prices on infra-marginal bids leading to mixed-strategy equilibria. This implies both higher prices and greater volatility in the spot market.

39. The degree of markup in the equilibrium is also affected by the probability β that the counterfactual line (with reduced capacity) is congested. The size of markup increases with β, both in pure-strategy and mixed-strategy supply function equilibrium. In the long term we expect demand to rise and β to increase. Therefore the mixed-strategy scenario will become more likely in the future.

Benefits accrue from portfolios of transmission investments

40. In a transmission network, investments in capacity typically have synergies that must be considered as a portfolio. Charging for the sum of individual benefits of these investments can misrepresent what these are.

41. Consider a series of lines acting as an interconnection, like the HVDC line together with the NIGU. If it is considered as two lines joined in series, then the estimated sum of the benefits for each individual asset added to the grid is smaller than the benefits of the lines added as a pair. If we consider a counterfactual, in which one of the line expansions is missing then the benefits will be reduced almost as much as if both were missing. Calculating benefits on the two lines separately thus overestimates the benefits of the same increase in overall transmission capacity.

42. On the other hand, if the interconnection has two lines in parallel, then by a similar line of reasoning the sum of the benefits each estimated from a counterfactual with one line missing is typically smaller than the benefits computed when the pair of lines is treated as one asset. This is because each line contributes a larger marginal benefit on its own than in conjunction with the other line.

The importance of VoLL

43. If demand is so high that the counterfactual SPD solve (with a reduced line capacity) is certain to have congestion, then the value chosen for value of lost load (VoLL) becomes key in determining the SPD charge that consumers should pay.

44. The SPD charge might affect load in the long term. Consider an example scenario where the transmission capacity from a demand node to a generator's node is doubled. This transmission expansion is to be paid for through the SPD charge. After some years, demand grows to the point where the extra importing capacity is used nearly every day.

45. Suppose that the monthly cap on SPD revenue is not binding, so that all the difference in surplus is appropriated as a transmission charge. As there is plenty of transmission capacity, the entire peak load can be satisfied by imported energy. Consequently the local marginal price of energy in this period is modest. If the local demand exceeds even slightly the sum of counterfactual transmission capacity and local peaking generation, the difference in consumer surplus with that of the counterfactual dispatch will be large; specifically, this would be the portion of the new import capacity used times the difference between VoLL and the current price of energy in this peak, times the length of the outage period within the counterfactual.

46. Furthermore, if due to the removal of import constraints the local peaking generator has closed down, then the counterfactual price goes to VoLL with even greater probability, and the amount of lost load in the counterfactual can become very large. This may have the unintended consequence of plants remaining within the market where much of their value is due to their ability to affect prices within counterfactual scenarios.

47. Both demand growth and the closing of local peaking generation will, over time, cause the probability of lost load in the counterfactual to rise. The Electricity Authority in its beneficiaries-pay working paper consider the possibility of 1% and 3% probabilities. These values are from a 2017 model. But in scenarios like the one described above, lost load in the counterfactual can occur with much larger probability. The charges levied under the SPD method will in such cases depend heavily on the alternative to transmission chosen by the Electricity Authority for the counterfactual scenario.

48. When VoLL plays such an important role, the entire transmission revenue is recovered in a small number of trading periods. The charges will depend very much on defensible estimates of VoLL, and the confidence in the counterfactual outcomes.

49. According to the Electricity Authority's own modelling (Beneficiaries pay working paper, 2014), the majority of SPD charges are paid by load. The periods with the largest perceived benefits are those when the counterfactual price is VoLL. VoLL is derived from a counterfactual constructed by the regulator depending on what sort of generation would hypothetically have been built instead of the transmission asset.

Area of benefit charge

50. The TPM working paper proposes (section 6.78) that "allocation of the AoB charge to generation should be on a MWh basis. Allocation to generation on a MWh basis avoids the problem that allocating charges on a capacity basis would disincentivise peaking generation."

51. Even under a price-taking assumption, charges levied per MWh will increase the apparent marginal cost to firms and lead to allocative inefficiency where cheaper distant energy is rejected in favour of local expensive energy because the short run marginal cost of transmission has been exaggerated.

52. EPOC recommends that the AoB charge be allocated on a HAMI basis, since a per MWh charge can be distortionary during low-price periods. The area of benefit for generation for a transmission investment is the upstream (export-constrained) end. A capacity charge would discourage peaking capacity at the upstream end of the line. This is not a perverse incentive, as peaking plant should be encouraged at the downstream (import-constrained) end of the line.

Other Issues

The Deeper Connection Charge

53. Flow-tracing charges like the deeper connection charge have support from the economic literature (Green 1997, Bialek 1996, Kattuman et al. 2014, Pérez-Arriaga and Smeers 2003). This is because they approximate beneficiaries-pay schemes, but are less open to strategic manipulation.

The HHI threshold

54. The HHI threshold seeks transmission assets in which market concentration is high. The rationale in restricting attention to these assets is that one might expect transmission costs to be shared based on some contractual agreement. EPOC regards this distinction as arbitrary and possibly distortionary, and recommends that it not be adopted.

55. Having an arbitrary policy such as this can lead to firms altering their behaviour in the wholesale market to lower the HHI index. For example if there are three firms, then they may be able to socialise the cost of a line which they use, by changing their offer strategies to decrease the HHI.

Measuring capacity

56. Measuring EDBs' offtake capacity as the sum of all ICP connections and large load customers' as AMD is a built in bias against EDBs. Some degree of bias may be justifiable on the basis of Ramsey pricing, however the partition of cost between EDBs and direct connect customers should really be made an explicit parameter of the methodology if different yardsticks are to be used for the two classes of customer.

Conclusions

57. The grid has multiple uses - energy transport, supply reliability, option for alternative supply - that can all be priced. However, we believe that the proposed TPM puts too high a price on the energy transport use compared to the others.

58. With transmission pricing depending only on energy flows the system risks entering a death spiral as loads go off-grid, leaving fewer customers to service the fixed costs of the transmission network. The danger here is that Transpower will be left with stranded assets for which it is not possible to recover the costs.

59. To varying degrees the LRMC, SPD and AoB charges proposed by the Authority depend on the amount of energy attributable to a transmission customer flowing in every period. Each marginal MWh generated or drawn in each trading period has some positive transmission cost associated with it, meaning that the marginal incentives are equivalent to short-run pricing of transmission.

60. If the Authority wishes to price the capital costs of transmission into the short-run market there are much simpler, more transparent ways of doing so, such as flow tracing or the explicit price in SPD that we present in Appendix 2.

61. To be truly future-resilient, the Authority should aim to integrate transmission pricing with the transmission investment decision process and also with a market for generation capacity. An important aspect of this would be enabling the demand-side to bid in for their desired maximum demand, as illustrated in Appendix 1.

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Appendix 1

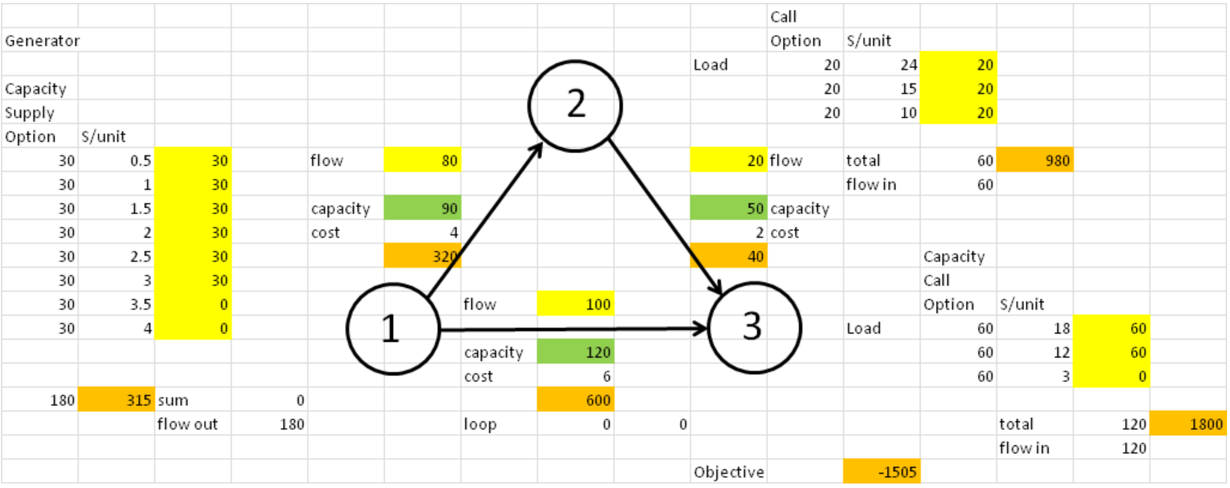
Example of a capacity auction

Each consumer submits a demand curve for their grid connection capacity in each period of the day. The value placed on a level of demand is not the same as an energy charge, but indicates the consumer's marginal utility for connection capacity at this time.

Each supplier of energy submits a supply offer of available capacity in each period of the day. This value placed on a level of supply is not the same as an energy charge, but indicates the generator's marginal cost for making the capacity available for bidding into the market. This availability charge will typically be smaller than the energy charge.

The grid owner seeks some payments for the transmission capacity they have built. They impose an option charge on each line. Given this grid the capacity auctioneer clears the auction for supply through the grid to the demand in each period. If demand is cleared then the consumer holds a call option to buy the cleared quantity at the spot price. If demand is not cleared then there is insufficient capacity to meet this requirement, and the consumer can expect to have its load curtailed at this amount.

An example of an auction is shown in Table 1. Here the lines in the grid have equal reactances. The line capacities are shown in green. The supplier offers capacity in increments of 30 MW, and the loads bid for call options on capacity. The cleared quantities are shown in yellow and the payments (assuming a pay-as-bid structure) in orange. With pay-as-bid payments the auction earns a surplus of 1505. The lines (1,2), (2,3) and (1,3) are each made payments of 320, 40 and 600.



										Call					
Generator										Option	$/unit				
									Load	20	24	20			
Capacity										20	15	20			
Supply										20	10	20			
Option	$/unit														
30	0.5	30		flow	80				20	flow	total	60	980		
30	1	30									flow in	60			
30	1.5	30		capacity	90				50	capacity					
30	2	30		cost	4				2	cost					
30	2.5	30			320				40			Capacity			
30	3	30										Call			
30	3.5	0				flow	100					Option	$/unit		
30	4	0									Load	60	18	60	
						capacity	120					60	12	60	
						cost	6					60	3	0	
180	315	sum	0				600								
		flow out	180			loop	0	0					total	120	1800
													flow in	120	
									Objective		-1505				

Table1: Capacity auction example. The generator sells 180 options for its capacity which are matched by 200 MW of transmission capacity and 180 call options. The consumer at node 2 buys only 120 MW of capacity options. Any load exceeding 120 MW will be disconnected.

Appendix 2

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 (600MW offered at marginal cost of $50 / MWh) at node B; 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 the 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:

Line Size		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:

Line Size		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, to go 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 at 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.