Beneficiaries-pay pricing and "market-like" transmission outcomes¤

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Abstract

The allocation of the capital costs for electricity transmission network assets is a challenging problem for which no perfect answer is provided by economic theory. In general, policy makers around the world have tried to balance the considerations of equity with the goal of encouraging efficient utilization of networks. Policy makers have also striven to avoid overly disruptive shocks to the level and structure of network charges. In this paper, we argue that attempts to measure network benefits, and assign costs accordingly, can be counter-productive for promoting the goals of efficiency and stability, and that equity concerns can be addressed by incremental adjustments without resorting to a strict application of the principles of "beneficiaries pay."

1. Introduction

The Electricity Authority (the Authority) is tasked with promoting the efficiency and competitiveness of the New Zealand electricity market for the benefit of consumers. In this role, the Authority has pursued an aggressive redesign of the methods for recovering the costs of transmission network investments, called the Transmission Pricing Methodology (TPM). The Authority's goals in this process have been to address perceived distortions in behavior caused by the current charging method, and to introduce more "market-like" elements into the transmission planning and investment process. The Authority is a relatively new institution, without much case history from which industry and other stakeholders can draw upon, and this is its most broad and impactful regulatory proceeding to date.

In this proceeding, the vast majority of the efficiency benefits claimed by the proposed reforms are speculative and dependent upon strong assumptions. A key feature is the reallocation of the costs of a subset of *existing* transmission assets between market participants. The only truly robust empirical finding from this process is that the proposed changes will result in a substantial shift in charges from some of those parties to others. Such shifts may be viewed as correcting historically unfair arrangements, but they are largely transfers from one set of participants to another that do little, if anything, to improve the economic efficiency of the New Zealand electricity supply industry.

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As a practical matter, there is no perfect solution to funding transmission infrastructure. Because the vast majority of these costs are fixed and sunk, their recovery from network users will inevitably distort the decisions of some users by some degree (either in the short-term, or long-term, or both) because prices for services must be set in excess of their marginal cost to recover all of these costs.[3] The goal should be to try to minimize the extent and impact of those distortions. A transmission pricing regime should also account for considerations of process and precedent. Another consideration should be to avoid the impression of arbitrary or over-reactive regulatory decisions that can undermine the confidence of investors in the stability of the process.

Given these considerations, there are multiple paths that could be that still respect the fundamental goals. For example, George Yarrow in his comments essentially argues that there are no obvious flaws to the process that led to the current TPM structure, and no obvious reason to change that structure.[4] We agree that the current transmission regime in New Zealand (encompassing short-term pricing, investment planning, and cost recovery) features most of the elements we consider to be an efficient and equitable system.

However, we remain skeptical of the practical utility of the concept of beneficiaries pay as a guiding principle for transmission cost recovery, and note that one of the elements of the current regime that has drawn strong criticism, the charges for the HVDC interconnectors between the South and North Islands, represents New Zealand's only previous experience with the beneficiaries-pay approach. The HVDC charges, unlike those for other projects, have been applied to a specific subset of participants, apparently due to the belief that this group (South Island generators) would be the prime beneficiaries of the project. This created concerns over distortions in the operating and investment behavior of these presumed beneficiaries. While these distortions have been at least partially addressed through recent changes in the mechanism used to allocate these charges between the beneficiaries, this experience demonstrates the difficulty of attempting to allocate transmission costs to presumed beneficiaries.

Therefore, in our opinion, the goal of establishing a durable, efficient transmission cost allocation scheme would be hurt rather than helped by the current proposal. A few targeted changes would be less disruptive and be just as likely to produce the long-term efficiencies desired by the Authority. Rather than "doubling down" on the beneficiaries-pay concept that backfired in the case of the HVDC lines, the Authority could consider the opposite solution to its concerns over the HVDC charge: treat the HVDC project like all the others, rolling them into the general transmission costs to be recovered through a combination of the existing connection and interconnection charges. With this, as with other proposed changes, faith in the durability of a charging scheme would be supported by a gradual transition of the burden of charges.

Such a revision would represent a positive step toward addressing both perceived inequities with the current HVDC allocation and any remaining inefficiencies created by

[3] Even if infrastructure costs were financed through public funds outside of the electric sector completely, the taxes and fees imposed to raise those funds would impact economic activity elsewhere to some degree.

[4] Yarrow, George. "Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology". February 2017.

the current HVDC charge. At the same time, it would represent incremental progress, and avoid disrupting charging structures to a degree that confidence in the stability of those charges is undermined.

Our comments in this paper are organized around five topics.

1. The viability of the general concept expressed by the Authority and several commenters of applying "market-like" outcomes to the context of transmission investment and charging.
2. A characterization, based on international experience, of the elements of what constitutes a best practice approach to transmission planning and cost recovery.
3. The advisability of changing the cost recovery mechanism for new assets only (which has previously been referred to by the Authority as "Application B").
4. The implications of the proposed changes in the transmission pricing policy for the ability of the regulatory process to enhance the efficiency of the wholesale market.
5. Experience with the beneficiaries pay approach from other markets and why they are unlikely to be applicable to the case of New Zealand.

2. Markets and Market-like Outcomes for Electricity Transmission

Throughout the TPM proceeding, a stated objective of the Authority has been to make charges "market-like"[5] and create outcomes resembling competitive markets through its charging structures. The Authority states that "*prices in workably competitive markets tend to be service-based, cost-reflective, and readily adaptive*," and has pursued its goal of making charges more cost-reflective under the belief that this would make them more market-like. However, the technology of building and operating an electricity transmission network makes it impossible to use a market mechanism to determine cost-effective transmission network investments and set efficient prices for use of the transmission network.

a) Natural Monopoly vs. Competitive Market

Building and operating an electricity transmission network is generally acknowledged to be a circumstance for which market mechanisms don't work. Specifically, once a transmission network is built for a given geographic area there is little need for, and significant expense associated with, constructing an additional transmission network. Consequently, the single transmission network owner could charge prices for use of the transmission network vastly in excess of those needed to recover the cost to construct the network, and still have a significant demand for its services.

In addition, operating a transmission network requires maintaining supply and demand balance at points of injection and withdrawal at every instance in time, which requires that a single entity operate the entire transmission network. Consequently, any competition in the provision of transmission network services would likely have to be between rival transmission networks for the same geographic area, and this would require the expense of constructing a duplicate transmission network.

[5] Page 5. Electricity Authority. "Transmission pricing methodology: issues and proposal. Second issues paper." May 2016.

Even using market mechanisms to fund investments in new transmission capacity has periodically been attempted and largely failed. There are few, if any, successful efforts to construct "merchant" transmission projects in wholesale electricity markets around the world. These are projects financed by the difference between prices at each end of the transmission link. The project owner recovers the cost of the project by purchasing electricity at a low price at the origin of the project and selling it at higher-priced location a termination point of the project. A number of transmission projects have been initiated as merchant projects, but these typically quickly transition to a standard cost-of-service transmission project.

The typical approach to building and operating the transmission network is to have a regulator or government agency coordinate the transmission planning process based on cost-benefit principles, and then run a competitive procurement process to determine both the entity and cost of constructing those upgrades that emerge from the planning process with economic benefits in excess of their cost.

New Zealand is one of the few countries to have attempted a very market-like approach to transmission pricing and investment. Transpower was initially thrown into a position of having to bilaterally negotiate service charges with each of its major users, with the result of chronic disputes and ongoing difficulties funding expansions. When users have no other option but the monopoly network owner for delivering electricity to final consumers, this outcome is hardly surprising. This experience, as Bruce Girdwood noted, "*illustrates that attempts to design market-like TPMs have been unsuccessful. Trying to design a TPM to perfectly signal both efficient short-term and long-run costs is extremely unlikely to be successful in practice*."[6]

This experience explains why all wholesale electricity markets operating around the world organize the transmission network planning and construction process as described above, and typically recover the cost of transmission network and set regulated prices for use of the transmission network that recover the cost of building and operating the grid.

A preferable interpretation of the Authority's statutory duty to "*promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*," would be to ensure that the monopoly networks do not get in the way of workable competition in the sectors where markets *can* reasonably be expected to work. This means a system of network charging that does not distort incentives for the competitive and efficient consumption or production of electricity. Rather than trying to force market outcomes on sectors where competitive markets do not, and likely cannot, exist, network regulators should work to ensure those networks serve the broader mission of enhancing competition in the sectors where market mechanisms are possible: wholesale and retail electricity sales.

b) Infrastructure Investment and Common Costs

In the language of economics, the vast majority of the cost of providing transmission network services are *common* to all users of a region's transmission network, and not caused by any single individual's use of the network. Specifically, these costs must be incurred regardless of how many customers are served or how many kWh of electricity are delivered to each customer. The same logic applies to virtually all of the costs of operating

[6] Girdwood, Bruce. "Transmission pricing, regulation and practice: A practitioner's view." July 2016.

a transmission network. Consequently, faithful application of cost-causation principles to assign network costs to specific market participants would result in almost none of costs of the transmission network being assigned to any individual market participant.

Attempts to assign the costs of a component of a regional meshed transmission network to specific market participants within that network is akin to attempting to assign the costs of an airplane taking off from one city and landing in another city to individual passengers on that flight. The cost of the airplane, fuel and crew must be incurred regardless of how many passengers travel on the flight. In the same sense, the cost of the transmission link must be paid for regardless how many customers are served at each end of the line, and how much electricity is transferred between the two locations. A very small fraction of the costs of traveling between the two locations is caused by any individual passenger on the flight, and a very small fraction of the cost of the transmission line is caused by any individual customer or kWh injected or withdrawn from either end of the line.

Of course there are cases where a set of specific customers can be associated with the need for components of a large network. The simplest case is the direct connection to the network from a specific facility. These costs are typically assigned to that specific network user, in New Zealand and elsewhere. Users in a specific local region such as the Auckland area, can be reasonably assumed to benefit disproportionately from the lower voltage network elements within their area. In recognition of this, many transmission systems make distinctions between lower-voltage transmission and higher voltage infrastructure and inter-connectors. Using the voltage level as a means to distinguish between projects is a simple, and transparent way to make distinctions between projects providing primarily local benefits and those benefiting regions or the entire country.

c) The Challenge of Determining Beneficiaries

The other important characteristic that electricity transmission shares with other network industries is that many of the benefits that the transmission grid provides do not come at the expense of other users. Absent congestion, access by one user to the transmission grid does not preclude other users from using the same network. Indeed, by facilitating the access of multiple producers and users, network capacity makes markets more competitive and beneficial for all its users.

Expanding transmission network capacity creates reliability benefits that are shared by virtually all industry participants by reducing the barriers to selling across regions, and reducing the market power of suppliers. These reliability benefits accrue to all electricity consumers. Further, the benefits provided by individual network assets are typically cumulative and interdependent. This means that it is almost impossible to measure the benefits of specific network assets outside of the context of the network as a whole.

This commingling of benefits is part of what makes the identification of the specific benefit to a specific customer so difficult and contentious. For example, suppose the demand of one customer increases and this requires an upgrade of the transmission network. To say that this customer is the only one who benefits from the transmission upgrade fails to recognize that all customers use this transmission line, and if their demand fell by the amount of the demand increase, the upgrade would no longer be necessary. Viewed from this perspective, all of the other customers are also benefitting from the upgrade because they continue to receive electricity in spite of the increased demand of the one customer.

Another challenge with a beneficiaries-pay approach is that market participants have a strong incentive to inflate their claimed benefits when such claims might make the difference in building a project, but underestimate their claimed benefits if they view a project as likely to be chosen. Specifically, when the benefits of the network exceed the costs, the temptation to try to "free-ride" on the willingness of others to pay for network upgrades can be strong. Consequently, even approaches that rely on the self-reported benefits estimates that each market participant obtains from a project, and allocate costs on that basis, are likely to result in arbitrary cost allocations.

d) Competitive vs. Discriminatory pricing

It is true that in most networks, some users benefit more than others, just as some consumers of beer enjoy it more than others (even though it costs the same to produce a pint of beer for each consumer, regardless of the benefits enjoyed). Presumably all who imbibe a pint expect a benefit as much or greater than they paid for it, or else they would not have bought it. Similarly network users experience benefits in excess of their charges, or else they would not be connecting to, or consuming from the network.

Indeed, in most competitive markets, prices paid by customers are uniform and based upon the benefits of the marginal consumers, rather than calibrated to extract the benefits enjoyed by specific customers. This form of discriminatory pricing is much more common in imperfectly competitive markets.

One such setting in fact, is in regulated-monopoly environments. Indeed, we do not argue with the spirit of discriminatory pricing. As we describe below, it should be deployed in a manner that maximizes the benefits created by the network, rather than in a fashion that attempts to extract those benefits.

We conclude therefore, that market-like solutions are not particularly desirable in the transmission network contexts. Further, despite its stated objectives, the charging regime put forward by the Authority is not particularly market-like in its attempt to discriminate between and extract the surplus of particular users

3. A Blueprint for Efficient Transmission Pricing and Investment

The attributes of electricity transmission described above, along with the lumpy nature of network investments, imply that a market mechanism will not produce ideal outcomes for the expansion of network capacity. No one seems to be directly suggesting that transmission be expressly left to market forces, even though the term "market-like" is frequently used. We support an approach to network investment and charging that maximizes the ability of the transmission network to promote efficient markets for the buying and selling of electricity, rather than of electricity transmission. Transmission is a means to implementing competitive markets in other parts of the industry, rather than a sector that is ripe for competition itself.

In our view this involves a policy that utilizes transparent, coordinated planning and investment in a network "backbone" that can also accommodate "merchant" transmission projects that would be financed outside the structure of the TPM, as described below. Charges for the use of this network backbone should be designed with an eye towards maximizing the efficient utilization of that network. This means charging for congestion during periods when capacity is tight, and minimizing fees for using the network when there are no binding constraints. A network cannot create benefits if it is priced in such a way that no one wants to use it.

a) Elements of an Efficient Transmission Investment and Charging Regime

An efficient transmission governance process therefore involves the following elements.

- First, there should be oversight of a national or regional planning process by an independent agency tasked with encouraging and approving network investments that increase net benefits to electricity consumers, and preventing those that do not.

- Second, this process should be informed by, but not unduly swayed by the claimed investment plans of specific generation resources or large customers. We have referred to this relationship as "transmission leads generation." To the extent that specific alternative investments, such as the deployment of storage technologies, can be identified or are revealed to the independent agency, they can be considered as alternative network investments.

- Third, firms that require investments for their individual direct connection to the national grid should be responsible for financing those investments. Further, if firms wish to finance other network investments not included in the national plan described above, these also should be accommodated subject to reviews that ensure such investments do not harm or degrade other portions of the network. Experience shows that the merchant transmission model is uncommon, and should not be relied upon for critical investment, but should also be allowed as long as those investments do not reduce capacity elsewhere in the network.

- Fourth, charges for utilization of the network should include efficient congestion pricing methods, such as locational marginal pricing. Locational marginal prices (LMPs) provide efficient signals to generators and consumers about the relative costs of network usage at a given location. To the extent these signals are unaffected by the location decision of a firm, LMPs also provide efficient incentives for generation investment. A more difficult question surrounds planning and load forecasts. Network investments are typically driven by forecasts of peak demand, and can therefore be described as "following load." To the extent that distributed resources can reduce peak demand, they can endogenously impact network investment. In such circumstances charges to peak demand above the hourly LMP, which provide incentives to reduce peaks, can be justified.

- Fifth, because congestion revenues from an LMP market will typically be insufficient to recover the full capital costs of the network backbone, remaining capital costs should be recovered according to best practices for natural monopoly regulation. This implies some form of "Ramsey pricing", in which less price-responsive customers pay a larger share of the costs of the network. In this way, costs can be recovered while minimizing distortions for the use of the network.

  Traditionally, Ramsey pricing in a transmission network setting implies placing a disproportionate, if not complete, share of network costs upon load. Consumers are typically less sensitive to prices than generators, particularly with regards to volumetric (per MWh) charges. However, the advent of relatively low-cost distributed generation (DG) technologies is starting to challenge this conventional wisdom. Many distribution companies around the world are increasingly worried about the loss of load to DG, and about the threat that poses to the cost recovery of their network assets.

b) *Efficient Cost Recovery and the Beneficiaries Pay Approach*

Because most users of transmission networks enjoy aggregate benefits well in excess of costs, there are potentially many possible allocations of costs that fit the general framework described above. Moreover, as noted earlier, determining the economic benefit each market participant receives from the existence of the transmission network, let alone a specific transmission network asset or expansion, is not an objective process. It typically relies on assumptions about the behavior of *all* market participants to recover an estimate of the benefit that one market participant receives. The methodologies are not based on the economic principles of cost causation, for the reasons discussed earlier.

Each approach creates different sets of winners and losers on the margin. This can understandably provoke strong interest within the groups of losers and winners, but that interest does not necessarily imply inefficiency or a lack of durability. Specifically, virtually any cost allocation mechanism for recovering the cost of the transmission network will distort the behavior of some market participants. For example, charging generation units to use the grid reduces their economic incentive to inject electricity into the grid, and charging loads to use the grid reduces their economic incentive to withdraw electricity from the grid. The goal of designing a transmission network charging mechanism is to reduce these distortions in the energy and ancillary services markets from recovering the cost of the transmission network.

Allocating the costs of networks according to the concept of beneficiaries pay can be an attractive principle until one recognizes that any assignment of fixed network costs distorts behavior – either in the short term (through changes in operating behavior), or long term (through changes in investment incentives), or both[7]. While we consider this approach more reflective of social or regulatory policy than of markets, there are nonetheless appealing equity aspects to the notion that one can assign costs to those who gain the most. However, if the entity that benefits most from an upgrade, and therefore pays the highest per kWh cost to use the grid, is also the one most able to take actions reduce the amount it pays for the grid, then a "beneficiaries pay" principle can lead to very inefficient energy and ancillary services market outcomes. The risk is that charging parties too much, or in an inefficient way, can undermine the very benefits upon which the case for the upgrade were predicated. One does not want to discourage use of expensive infrastructure simply as a consequence of attempting to recover sunk costs.

Most commenters to this proceeding agree that avoiding distortions that discourage use of the network is a desirable goal. The disagreements revolve around the notion that sacrificing efficiency in the short-run is necessary to gain greater efficiency in the long-run.

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[7] We note that the Authority is attempting to avoid distorting short-term incentives by making the charges largely fixed and independent of usage (a noble, if likely impractical objective), however the allocation to beneficiaries would still have the effect of disincentivising investment that might have made use of otherwise underutilised investments.

The Authority has stated during this process that one of the main benefits of change will be a more efficient transmission planning and investment process.[8] Such impacts are so speculative that the cost-benefit analysis supporting the proposal does not even attempt to model it. These benefits could very well be negative. Several commenters have remarked, and we concur, that introducing cost allocation into the process of modeling and evaluating transmission projects has as much potential to disrupt and delay that process as it has to improve it. Even then it is no guarantee that such a regime would be any more durable than the current one.

Ironically, a prime example of the risk is the current HVDC charge, one of the most contentious charges in the current regime. It is interesting to note that this charge, so disliked by the Authority and others in this proceeding, actually represents an early attempt at a beneficiaries pay approach. Charges for this project were assigned to South Island generators under the belief that they were the primary beneficiaries of the asset. The fact that this arguably turned out to *not* be the case is a prime example of the pitfalls of beneficiaries pay. The arguments that the current charging structure creates inefficiencies in relation to generation location decisions (i.e., investors would be less willing to invest in the South Island and make use of the HVDC link than the North Island, ceteris paribus) also highlights the problems with allocating costs according to some method other than Ramsey pricing.

Forecasting benefits far into the future is very difficult, and yet updating charges according to revised benefits calculations risks distorting behavior. Proponents of changing this charge are not rejecting or embracing the principle of beneficiaries pay, but rather the methods used to calculate the benefits. Indeed according to the analysis of Meridian, the benefits of the HVDC line could very well be spread relatively evenly throughout the country.

Given the speculative nature of the efficiency benefits, we see the main issue at stake in this proceeding to be one of reallocating those costs and benefits. Such questions of fairness and equity are certainly important to a regulatory process but need to be seen as such. Questions must also be asked about the long-run implications of changes designed to redress currently perceived equity imbalances. As we discuss below, a regulatory process that is perceived as modifying established policies and procedures primarily because one set of parties views them as ex-post unfair, can sow doubts about the durability of any decisions made by that regulator.

4. Application of the AOB Charge to Sunk Assets

One of the aspects of the current proposal that merits further discussion is the question of whether to apply the proposed AOB charges to a subset of existing assets (previously referred to by the Authority as "Application A") or to limit it to apply only to future assets ("Application B"). Many commenters have reached the conclusion that a tariff structure intended to improve *future* investment decisions has no relevance for the recovery of *existing* asset costs. We agree. While we are skeptical of the arguments that the AOB

[8] "*The key issue here is that the TPM is not sufficiently service-based or cost-reflective and so grid users have poor incentives to engage in the Commerce Commission's decision-making on grid investment, and poor incentives to reveal better grid investment options (including alternatives to transmission).*" Second Issues Paper. Xvi.

charge would in fact improve the investment process we are absolutely certain that it cannot improve *past* investment decisions.

Three arguments have been offered for extending the AOB charge to existing assets. First, doing otherwise would make the pricing regime overly complicated, or "confusing and burdensome" in the words of Stephen Littlechild[9]. Second, including such costs would in fact change current behavior, or reveal information, in ways that increase efficiency. Third, such a change would correct what some see as a historic wrong of limiting the recovery of the HVDC costs exclusively to South Island Generators.

With regards to the notion that the failure to apply different cost recovery principles retroactively would be confusing and burdensome, it strikes us that the opposite would be the case. A dramatic and considerable shift in the way infrastructure projects are financed is confusing enough, but could be justified if there is sufficient evidence of an improved planning and investment process. However, retroactively changing the nature of cost recovery for existing assets, with no justification based upon efficiency grounds, introduces more confusion and burden by enhancing the perception that the regulator is responding to the financial interests of specific effected parties.

Therefore one must consider whether there are efficiency grounds to such a retroactive change. This could perhaps be argued in the case of the HVDC charges, to the extent they do distort use of the *current* network, even after the changes to the recovery formula made by Transpower in 2015.[10] However, the arguments made by Professor Littlechild instead emphasize the prospect that such a change could "*reveal important information to improve the quality of future investments*."

We fail to see how exposing network users to inefficient current prices helps inform a planning process about future needs, except through unlikely serendipity. If somehow, for example, the sunk costs of current assets are applied to users in regions where future expansion may be looming, such a practice may accidentally recreate something approaching the Long Run Marginal Cost (LRMC) charges proposed in previous iterations by the Authority, and defer the investment for some length of time. Such an outcome, however would be purely coincidental and does not represent a solid argument for policy making. A more plausible outcome would be that these retroactive charges would be applied to regions determined to have benefitted from past expansions, and therefore would be among the less likely regions to need future expansions. Rather than sending efficient signals, this could perversely result in lower usage in regions that already have sufficient infrastructure, and higher usage in areas approaching capacity constraints.

The last point boils down to a fairness argument. Meridian has argued that the HVDC charge is both "*arbitrary and unfair*." They point out that "*it separates out the HVDC assets from the rest of the interconnection system and allocates charges on a different basis from the general methodology"*. They go on to argue that "*South Island generators have*

[9] Littlechild, Stephen. "Report on the Electricity Authority's Transmission Pricing Methodology Review". July 2016

[10] Meridian, for example argues that the current charges can inefficiently skew generation investment away from the South Island.

been singled out as the deemed beneficiaries of the HVDC assets and are the sole payers."[11] They present data on flows and prices relevant to the HVDC line that they argue are inconsistent with the conclusion that South Island generators are the sole beneficiaries. It is important to recognize that these points actually signal a condemnation of a form of beneficiaries pay, rather than a rejection of the existing cost recovery approach applied outside of the HVDC assets. Incremental adjustment to the HVDC charge, eased in with the help of a well-considered transition (that accounted for the adverse effects of rate shock, for example), would be a more obvious response than a wholesale overhaul of the entire charging regime.

It is also worth noting that neither Meridian nor the Authority recognize that even if the South Island generators' share of the HVDC link charges were reduced in line with their purported share of the link's total benefits (say, to 45% instead of 100%), this action would address some of Meridian's equity arguments, but not the efficiency issues highlighted. There would still be a disincentive to invest in new generation in the South Island relative to the North Island, and hence usage of the link would be discouraged. While the inefficiencies would be reduced, they certainly would not be eliminated as the Authority and its advisors have assumed.

5. Regulatory Stability and International Experience

The transition from nationalized or regulated electricity systems to liberalized markets supported by independent transmission system operators has, in most countries, featured many incremental steps. The gradual adoption of locational marginal pricing in many markets around the world stands as a good example of this process. As Paul Joskow noted in 2005, [12]

> *It should not be surprising that electricity restructuring and competition programs have inevitably been a process that involves a lot of learning by doing and ongoing changes to market rules, regulatory arrangements, and governance institutions.*

Thus we should not reject proposals simply because they represent change. However, it is important to recognize that many of these changes needed to be made because of, in the words of Joskow, the "*natural inclination of policymakers to treat the details of the restructuring program as a political rather than a technical problem.*"[13]

Thus we should not ignore the fact that change can be disruptive and counter-productive, particularly when taken as a means to reallocate profits amongst market participants. Around the world, policymakers face a strong temptation to constantly tinker with aspects of market design in ways that direct more rewards to specific constituencies. During the 2000s, regulators in several US states expended considerable energy, and created considerable uncertainty, in efforts to alter or reverse decisions from earlier in that decade

[11] Meridian Energy Submission Transmission Pricing Methodology: Issues and proposal: Second issues paper.

[12] Joskow, P. L. (2005). "The difficult transition to competitive electricity markets in the United States." Electricity Deregulation: Choices and Challenges: 31-97.

[13] Ibid.

in response to a perception (temporary, as it turns out) that liberalization had produced higher prices.[14]

This problem with regulatory commitment comes up in several contexts in power markets. When writing about generation investment, Joskow (2008) noted, "*policymakers have not been shy about ex post adjustments in electricity market designs and residual regulatory mechanisms, sometimes motivated by a desire to hold up existing generators opportunistically*." The obvious problem with regulatory changes viewed to be "opportunistic," in the sense that they are motivated by the perception of an ex-post unfair result, is that these actions make it much more difficult to attract new investment. In a capital intensive industry such as the electricity supply industry, where assets last for decades, regulatory decisions that are viewed as arbitrary or rushed can have a strong chilling effect on investment: "*It is now widely recognized that opportunism problems, whether by counterparties or government entities, can lead to under-investment.*"[15]

6. International Experience with Electricity Market Reform

We conclude with a discussion of the US experience with transmission cost allocation which, while not perfect, provides some useful lessons for the New Zealand context. The Authority has periodically cited the US FERC's Order 1000 and its language on cost allocation as a model for its proposal to apply the principle of beneficiaries pay to New Zealand.[16] However, the proposals in New Zealand have far outstripped the emphasis on beneficiaries pay than has been implemented in the US.

It is useful to consider the different conditions of electricity markets in the two countries at the time these reforms have been attempted. In the US, FERC Order 1000 and its predecessors were implemented because of general perception that previous reforms were insufficient to produce new transmission investment. To this point, geography also matters. The US and its Federal system has produced a decentralized and consequently uncoordinated planning and regulatory process in its electricity supply industry. Adding infrastructure within a jurisdiction (e.g., within a state, or, later, within an ISO footprint) has always been easier than funding infrastructure that connects different regulatory jurisdictions. ISOs have been reasonably successful at funding and constructing transmission projects *within* their regional footprints, but face greater challenges when building connectors *between* ISOs or major sub-regions of an ISO.

The push toward a beneficiaries pay approach was inspired in part to deal with this latter problem of connecting large regions operating under differential regulatory jurisdictions. There has been a belief that sharing costs between large regions in ways that would be at least roughly proportional to benefits would help reduce opposition to larger interregional connections. We believe the jury is still out on that hypothesis.

The contrast with New Zealand, however, is sharp. Unlike the US, Transpower has not

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[14] Borenstein, S. and J. Bushnell (2015). "The US Electricity Industry After 20 Years of Restructuring." Annu. Rev. Econ. **7**(1): 437-463.

[15] Joskow, P. L. (2008). "Capacity payments in imperfect electricity markets: Need and design." Utilities Policy **16**(3): 159-170.

[16] Electricity Authority. "Transmission pricing methodology: issues and proposal. Consultation Paper." October 2012. Pages 43, 92, and 104.

had to overcome a need to acquire approval from a series of regulatory agencies that each might be dominated by parochial interests. The market in New Zealand enjoys many institutional advantages lacking elsewhere, including a single transmission network, owner, a transparent regulatory process for review and approval of network investment, and the application of LMPs to generation and loads to provide proper signals of network congestion in real time. The perceived appeal of beneficiaries pay in other countries has been as much due to the absence of advantages present in New Zealand (e.g. the lack of LMP in the UK, or the overlapping jurisdictions in the US), as they are to the fundamental advantages of beneficiaries pay itself.

The experience in California[17] provides a relevant model of adaptive but incremental adjustment to changing conditions. While compliant with FERC Order 1000, charges for higher voltage regional transmission projects are overwhelmingly recovered from load in a uniform transmission access charge. Charges for lower voltage (less than 200 kilovolts) projects are recovered through a charge to load only in the region in which the project is located. The CAISO successfully argued that network benefits from regional transmission projects were sufficiently diffuse in its system that such a shared uniform charge was consistent with principles of beneficiaries pay.[18] This system may now expand beyond California, however, and its transmission charges will likely evolve in ways that should be attractive to the New Zealand context.

First, charges for *existing* projects will be continued in a manner consistent with how they have previously been allocated. Despite the changes to the ISO footprint, there is almost no desire to revisit allocation of projects already in place. Second, charges for *new* investment will continue to be differentiated at a regional scale to distinguish between large inter-regional investments and those implemented on a smaller scale. The costs for smaller scale lower voltage projects will be borne by the sub-region in which they are installed, rather than shared by the entire system. Third, costs for *new* high voltage regional projects will be proportional to an estimate of the benefits calculated at rather highly geographically aggregated level (e.g. California vs. PacifiCorp's Eastern system).

Another aspect of US transmission pricing worth noting is the allocation of costs to load-serving entities. Allocation based upon coincident peak usage, as is currently the practice in New Zealand, is not uncommon.[19] One exception has been the California ISO, which currently allocates costs based upon volumetric usage. However this CAISO practice has come under increasingly vocal criticism and will likely be revisited next year.[20]

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[17] California ISO. "Transmission Access Charge Options for Integrating New Participating Transmission Owners - Issue Paper". October 23, 2015. https://www.caiso.com/Documents/IssuePaper-TransmissionAccessChargeOptions.pdf

[18] Federal Energy Regulatory Commission. Order on CAISO Order 1000 Phase 1 Compliance Filing. ER13-103-000. April 18, 2013. https://www.caiso.com/Documents/Apr18_2013Order-Order1000Phase1ComplianceFilingER13-103-000.pdf

[19] In PJM, for example, there is a monthly demand charge for zonal and non-zonal network load based upon monthly and daily network loads at the time of the annual peak of zone in which the load is located. (Section 34 of Open Access Transmission Tariff) http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf

[20] California ISO. "Review Transmission Access Charge Wholesale Billing Determinant - Issue Paper." June 2, 2016. http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeWholesaleBillingDeterminant.pdf

7. Concluding Comments

As emphasized several times throughout our report, there is no perfect solution to planning and pricing of transmission infrastructure. Because the vast majority of these costs are fixed and sunk, their recovery from network users will inevitably distort the decisions of some users. We believe that the goal of the transmission pricing process should be to minimize the magnitude and impact of those distortions. Another consideration should be to avoid the impression of arbitrary or over-reactive regulatory decisions that can undermine the confidence of investors in the stability of the regulatory process, therefore their ability to achieve cost recovery.

We support an approach that attempts to facilitate a competition in wholesale and retail electricity sales, not in the provision of transmission network services. We see little reason to change cost allocations for existing transmission projects unless there are clearly demonstrated market efficiency benefits. Regulatory stability and credibility are particularly important for the Authority to establish early in its regulatory life, to ensure that it creates a hospitable environment for new investments and entry of generation unit owners and electricity retailers. Finally, we believe that the experience with the beneficiaries-pay approach from other markets is unlikely to be applicable to the case of New Zealand.