

*This chapter begins by summarising the institutional environment for addressing questions of investment adequacy and security of supply. A discussion of issues confronting electricity investment then follows. Supply-security issues are unpacked in greater detail, with an appraisal of mechanisms proposed to encourage “necessary” investment, a discussion of the implications of New Zealand’s reserve generation scheme for supply security, and a suggested alternative to either of these. Grid investment is treated separately, focusing on the ongoing tension between centralised decision-making and decentralised, market-based approaches to grid investment. Technical and institutional alternatives to the transmission planning arrangements either tried or currently used in New Zealand are offered. Finally, solutions to resolve the impasse that can arise between grid and generation investments (and demand-side measures) are compared.*

## INTRODUCTION

### *An Important Crossroad*

New Zealand’s electricity sector is at an important crossroad. It is possibly already about to entrench traditional solutions at the expense of innovation and private investment – and to do this for much of the next 50 years (since the grid is now overdue for new and typically long-lived investment). In part this direction has been justified on the basis of short-term supply-security considerations that appear to be both uninformed by history and arguably misconstrued. However, such considerations reflect a more general shift towards central planning for which winter supply crises and the 2000 Electricity Industry Inquiry merely provide a pretext. This shift has the potential to exacerbate, not resolve, perceived problems.

Previous chapters have focused on matters such as governance, market power and regulation, noting that each has important implications for the incentives and requirements for any new investment in the electricity sector. In this chapter we see that the reverse is equally true – that new investment in the electricity system has important implications for governance, market power and regulation. Together these constitute relationships requiring simultaneous solution when attempting to devise a reformed electricity sector maximising welfare over time.

Reversing two decades of shifts towards decentralised, market-based solutions to electricity requirements in favour of the more centralised command model of the past is not the “crossroad” referred to above, although it certainly reflects the nature of recent decisions about the sector and increases its import. Instead this crossroad refers to the way in which decisions about the national transmission grid and its upgrade

and expansion are to be made, and this interfaces with governance of the sector more generally. These decisions will either enhance and support the thrust of reforms to date – encouraging competition as a means of benefiting consumers, by better aligning the physics and economics of electricity provision and thereby also encouraging market-initiated and -funded solutions – or they will reduce or even reverse this direction.

*The Grid is the Nub*

The focus on the importance of the grid for future sector reform is a natural consequence of Kirchhoff's laws in interconnected AC networks. Because of these laws traditional economic solutions struggle to address the externality, "public-good" and scale-economy implications of electricity networks. As discussed in Chapter 9, even small grid expansions can significantly affect the scope and intensity of competition in an interconnected electricity system. Considerable attention has been devoted in reforming countries to engendering market forces and competition in the relatively tractable area of generation, but transmission reforms remain tentative and exploratory (where they amount to anything more than taming by regulation of a problem relegated to the "too-hard basket"). Calls are increasingly being made either for new economic solutions to reflect the underlying physical issues (e.g. financial transmission rights, FTRs), or, more recently, for changes to the way grids are engineered to better facilitate economic solutions (more below). While opting for regulation or new economic solutions are moves that are relatively easy to refine or reverse (although they possibly have long-term implications), decisions on major long-term grid investments can set the framework for any future solutions for decades to come.

While a focus on transmission investment decisions is of importance, issues of generation and demand investment clearly also need attention. Together, transmission, generation and demand-side measures are critical contributors to "security of supply",<sup>1</sup> the achievement of which is an increasingly debated and much misunderstood topic in liberalised electricity systems worldwide.<sup>2</sup> Furthermore, generation and demand investment also affect the competitive make-up of a reformed electricity market. Since they also affect transmission on the grid, generation and demand measures share important interactions with grid capacity and so affect the location, timing, scale and nature of any new generation or demand-side investments. All three require ongoing appraisal if changing patterns of electricity demand are to be satisfied. The question is "how?"

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<sup>1</sup> Here we use "security of supply" to mean more than simply the real-time maintenance of system balance. It instead refers to the inducement of electricity investments (in generation, transmission and demand management) and demand curtailment, reflecting users' expressed and dynamically changing preferences for ongoing electricity supply and consumption, and their willingness to pay for alternative levels of longer-term supply security.

<sup>2</sup> See Meade (2005) for an extensive analysis of the meaning of electricity supply security, a summary of the issues confronting generation investment, a critique of capacity mechanisms sometimes used to encourage generation investment, and a proposed alternative to ensure appropriate investment levels in liberalised electricity systems.

## WHAT NEW INVESTMENT IS ACTUALLY “NEEDED”?

Before we look at the “how?” question, it is useful to consider the “why?” Prior to New Zealand’s reforms, investment in electricity capacity – whether in generation or transmission – was regarded as a matter of national priority, facilitating the development of an otherwise relatively undeveloped economy. Even now the development of the sector is seen as important to the development of the wider economy, but today the arguments are couched more in terms of the need for reliable electricity supply so as to retain and encourage investment in New Zealand industry and to reliably meet household electricity demand in an e-world. However, committing billions of dollars to electricity-sector investments is clearly a very blunt (and potentially welfare-reducing) instrument for achieving these ends, and increasingly a number of competing considerations have given cause to reflect on when, how, why, and by whom any new investments should proceed.

To suggest that new electricity investment is required to meet ever-growing electricity demand, simply begs the question. Just because demand has historically grown at one rate or another, does this imply either that such demand growth will continue or, more importantly, that any or all of it ought properly be met by investments in new capacity? Will any or all of that demand even materialise if electricity prices must rise to justify new investments? Similarly, to suggest that no electricity users should have to suffer the prospect of voluntary savings campaigns in impending or actual winter power crises but instead be assured an ongoing supply is a major “call”; almost certainly it is not economically justifiable from a national perspective. As discussed in Chapter 6, some electricity users can and do reduce their consumption when energy is scarce, whether voluntarily, grudgingly or enthusiastically (e.g. when they have fixed-price contracted supplies they can sell at a profit to other users who are prepared to pay higher prices for ongoing supply security). It is a mistake to suggest that all electricity users want more power at any price, or that they all require the same security of supply.

So why then do we invest in new electricity capacity? The historical rationale – to facilitate development of the economy – has some appeal, but the implementation of that policy was far from an unmitigated success. Further, the restricted meaning of development used then as the expansion of tangible goods and services is much less appropriate than the wider conception of evolution of the services provided, including enhancements to the environment, in a modern e-economy. The term “development” as used in New Zealand then had more to do with the narrow definition represented by the “development” plans of the “eastern-bloc” planned economies of earlier eras. As discussed in Chapter 5, evidence presented in Galvin (1985) suggested the process was inclined towards investments in large-scale new capacity (based on systematic over-estimates of demand) that came in over-time, over-budget, in the wrong sequence, and at power prices higher than those justifying their adoption. Even with the resulting overcapacity, supply security did not result. A more enlightened approach is now desirable.

## ISSUES CONFRONTING NEW GENERATION INVESTMENT

Historically, electricity-sector investments – particularly generation and transmission – involved ambitious large-scale projects that were feasible because they were undertaken by central government. Not only were they of a size (and therefore cost) that was beyond the means of local government or then private enterprise, but they enjoyed the facilitation of legislation (indeed, private investment in hydro generation was precluded by legislation giving government control over water use). Today central-government budgets are typically more committed to social spending than to national investments in bricks and mortar, and subject to borrowing constraints. Environmental concerns make the political attractions of large investments, including national advancement and employment, less clear-cut. Resource management law can not only make obtaining approvals for new investments much harder to obtain but also in New Zealand under the Resource Management Act 1991 (RMA) such approvals are typically no longer in the hands of central government. Instead they are delegated to local authorities with local interests at heart.<sup>3</sup>

Compared with those of previous decades, the rules have significantly changed. Taxpayers no longer view the interests of electricity users as being the same as their own, and a major change in policy would be required for governments to undertake major capital expenditures that increase national debt.<sup>4</sup> Electricity users want to be sure they are paying no more than they have to for electricity and they want reliable supply – even households rely on electricity-using digital devices at most times of the day. Local communities want to see any new investments made anywhere but in their back yard. Environmentalists seem to prefer financially unviable but environment-friendly forms of generation instead of large-scale investments (or even small hydro generation, given its environmental impact), but typically only as a second preference to demand reduction.<sup>5</sup> Typically none of these want to see higher electricity prices. This creates a complex need to balance multiple and sometimes competing objectives, and begs the question as to how the balance should be determined.

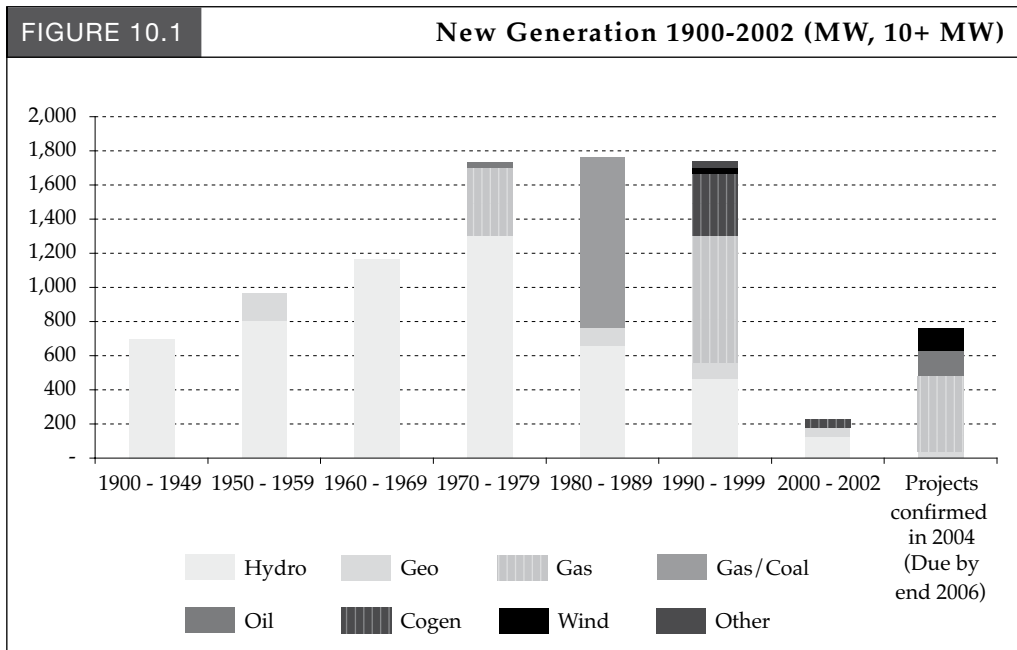
Central government is often regarded as the leading contender, but this too begs the question as to whether central government should determine the required solutions, or instead create a framework within which solutions can be determined by those

<sup>3</sup> See Hawke (2003a, 2003b) for an economic discussion of the RMA framework.

<sup>4</sup> In this regard governments benefit from the decentralisation afforded to state-owned enterprises (SOEs), as major SOE expenditures typically require retained earnings and external borrowings rather than injections of taxpayer funds, and SOE borrowings enjoy no government guarantee (although recent government moves, such as its underwriting of Genesis's gas exploration risks, signal a shift in this regard).

<sup>5</sup> A 60 MW hydro power scheme on the Arnold River on the West Coast was reportedly scuttled by the Minister of Conservation because it required the flooding of a portion of reserve ("Jury 'Still Out' on West Coast Mine", *Dominion Post*, 11 March 2004). The project was expected to help relieve transmission constraints on both the east and west coasts and in the north of the South Island, and was consistent with other government policy of encouraging local communities to invest in distributed renewables-based generation, in this case to the point of self-sufficiency. Environmental constraints have apparently proved binding.

concerned – the issue of centralisation versus decentralisation pervades this appraisal. The thrust of the reforms in New Zealand to date has been to place a greater burden for these solutions on market participants – but always subject to the macro parameters of economic, energy and environmental policies, and constrained by any associated laws (e.g. the RMA). As shown in Figure 10.1, despite the many constraints that market participants have faced since the commencement of the reforms, significant generation investment has continued at much the same rate as in preceding decades.<sup>6</sup>



Source: Ministry of Economic Development (2003), and *After Aqua: NZ's Electricity Future* address by Minister of Energy to "National Power NZ 2004" conference, Auckland, 31 March 2004.

Note: Figures are for plant in use as at 2002, and hence exclude plant decommissioned up until then.

The important difference between post-reform generation investments and those pre-reform is that the scale, type, location, and timing of more recent generation has been based to a greater extent on electricity users' evaluations of electricity's worth (as signalled via wholesale electricity prices), the costs of transmission congestion, and the costs of new generation capacity (subject to the raft of other constraints confronting market participants). Given the considerable financial sums and procedural difficulties (e.g. lengthy RMA consent processes) involved, the fact that private investors and more commercially focused state-owned enterprises (SOEs) have undertaken these long-

<sup>6</sup> While the location of new generation investment in the 1990s continued to reflect energy-supply sources (e.g. southern hydro and Taranaki gas), around 30% of new generation was located near to the major and growing Auckland demand.

term investments without the need for central planning is no mean feat (and to the market-minded, not unexpected).

Two challenges remain, however: the decentralised provision of supply security, and investment in the grid. The alleged lack of supply security arising from low lake-inflows has been used by central government as a justification for the centralisation of industry governance under the new Electricity Commission (which started business on 1 March 2003), and for its requirement that the Commission contract for reserve generation capacity (and/or interruptible load) funded by energy levies so that voluntary power savings need not be called for during future inflow crises. The Commission is also charged with determining the pricing and investment policies of the grid operator, Transpower. Each merits further discussion.

The most fundamental challenges to generation investments required to meet anticipated demand growth lie not in the design of the reformed electricity sector but elsewhere. Rapidly diminishing known gas reserves and uncertainty regarding future supplies constrain new gas-based generation. Uncertainty regarding long-term climate-change policy creates the spectre of greenhouse gas emissions charges that have the potential to make or break new renewables-based and thermal generation projects. RMA consent processes and a major proposed variation to existing consent processes create additional uncertainties; and the absence of tradable or secure property rights for either water or carbon emissions (or views and airwaves uncluttered by pylons) hamper decentralised solutions to new generation and demand requirements. Finally, uncertainties arising from recently imposed changes to industry governance and in respect of future policy directions (such as energy price regulation and subsidies for renewable generation) also complicate long-term generation investments. These issues are discussed below.<sup>7</sup>

### *Gas Supply*

New Zealand's largest available productive gas field – Maui – was in 2002-2003 predicted to run down earlier than had been previously thought. The next two largest fields – Kupe and Pohokura – even if fully developed, represent a fraction of Maui's output. This alone has shelved or deferred significant new planned (and in some cases even resource-consented) generation capacity, including the 365 MW combined-cycle gas turbine "e3p" project planned by Genesis at Huntly, and a Contact energy 400MW combined-cycle gas turbine at Otahuhu. Urgent moves are under way to develop

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<sup>7</sup> It should also be mentioned that two other significant contingencies affect the short- to medium-term prospects of the electricity sector and hence uncertainty for investors. If NZAS should cease its smelter operations at Tiwai Point for whatever reason (e.g. declining world aluminium prices) then 15% of annual electricity supplied would be available to meet other demands, thereby deferring the need for new generation. If a major gas user such as Methanex, consuming 40-50% of the annual Maui off-take, were to cease production then the gas supplies released could affect the viability of generation projects already consented to but deferred because of gas-supply uncertainties.

alternative gas sources, and the development of facilities to import liquefied natural gas (LNG) is also being considered. Despite its environmentally bad name and the imposition of a \$15/tCO<sub>2</sub> carbon charge under the Kyoto protocols (which New Zealand has ratified), the possibility of indigenous coal reserves – currently enough to supply centuries of electricity demand – has gained prominence. The problem is that all such solutions take time, and the electricity industry may have been “caught short” by the downward revision of available Maui gas reserves and the lack of certainty about carbon-emissions-related taxes and subsidies.

### *Kyoto Policy*

Government has committed New Zealand to abiding by the Kyoto greenhouse gas emissions protocols. Carbon credits are already being allocated by government to projects (such as wind generation) that contribute to declining greenhouse gas emissions by reducing the need for thermal generation.<sup>8</sup> Carbon taxes of \$15/tCO<sub>2</sub> are to be levied on greenhouse gas emitters in the first commitment period under the Kyoto Protocol (2008-2012). However, the recent revision of government’s estimated net Kyoto position – from a \$500 million surplus to a \$500 million deficit<sup>9</sup> – means that both this rate and the promised cap on the tax of \$25/tCO<sub>2</sub> must be in doubt. The carbon tax and uncertainties surrounding future Kyoto policy materially affect the viability of all new wind and thermal generation projects – marginal wind projects may become viable and marginal thermal projects might become unviable; but then the reverse could also prove to be true.

Importantly, the adverse consequences of greenhouse emissions charges are not confined to new coal-based generation – the politically unfavourable alternative being hotly debated in the light of gas-supply constraints – but also affect gas-based investments and oil-based plant such as the new oil-fired plant to be constructed as part of the new Electricity Commission’s reserve generation scheme. An additional curiosity is that much of the opposition to coal-based generation is that it would entail increased greenhouse emissions, although Kyoto does not preclude this and instead allows for increases subject to emissions taxes – in short, even Kyoto allows for an optimal amount of increased greenhouse emissions rather than simply prohibiting them. In any case, this considerable risk to investors in new generation would be resolved if government, like the European Union, were to commit itself to a Kyoto-based tradable emissions regime irrespective of Kyoto’s development within and beyond the first commitment period of 2008-2012.<sup>10</sup>

<sup>8</sup> *Climate Change Policy Accelerates Energy Projects*, press release by Minister of Energy, 1 April 2004.

<sup>9</sup> “Kyoto Error Fuels Tax Rise Fears”, *The Dominion Post*, 18 June 2005.

<sup>10</sup> Indeed, such a move would signal that government is truly committed to reducing greenhouse gases rather than leaving international processes to determine this policy on its behalf.

*Project Aqua and Competition for Water Rights*

Until recently, the most significant generation project in process was the now-shelved scheme by Meridian (known as “Project Aqua”) to build six hydro stations with a combined capacity of 524 MW in the lower reaches of the Waitaki River. Highlighting the issue that major new generation projects now compete with other demands such as environmental preservation and those of other resource users (such as farmers relying on rivers for irrigation), the project was delayed by, among other things, uncertainty about the security of rights to water and government moves to change the way in which required resource consents are issued.<sup>11</sup>

Under the RMA, applicants for water rights require a resource consent from the local regional authority, and applications are evaluated on a first-come-first-served basis. The competition between Meridian and other water users for such rights, and the fact that the resulting generation capacity would bring benefits not confined to the local region and costs that would be so confined, prompted central government to change the manner in which this matter was to be resolved. New legislation was introduced to parliament to establish a modified procedure by which competing water-use applications on the Waitaki would be weighed.<sup>12</sup> Whereas the Electricity Commission and its task of contracting for reserve generation might be construed as a vote of no confidence in decentralised market-based decision-making, the centralisation of administrative water allocation decision-making for the Waitaki River can be regarded as a vote of no confidence in the RMA’s decentralised administrative decision-making approach. In either case other non-centralised decision-making alternatives are available, such as tradable water rights, but in the case of Project Aqua they do not appear to have been explored.<sup>13</sup>

In any event Project Aqua was shelved, with its SOE sponsor, Meridian Energy, citing a host of factors for its decision. Among these factors were process difficulties under the RMA, increased costs and risks associated with the extended decision-making process arising from the RMA-amending legislation, and uncertainties concerning any resource consents Meridian might obtain. These risks were compounded by legal action taken by Waitaki farmers over existing water rights, and Meridian’s concern that the RMA-amending legislation did not assure its ongoing use of existing water rights for its hydro plant upstream of the proposed development. Recent geotechnical investigations also required changes that adversely affected the project economics. The irony in all of this is that process difficulties arising under legislation intended to protect the environment now mean that large-scale hydro projects are unlikely to proceed, in the main, in favour of greenhouse-gas-emitting thermal generation. An

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<sup>11</sup> See Counsell and Evans (2004) for a discussion.

<sup>12</sup> Resource Management (Waitaki Catchment) Amendment Act 2004.

<sup>13</sup> An effective alternative to the centralised administrative allocation of water rights to reflect contemporaneous and successive competing uses for water, as well as national evaluations of that water’s worth, could, for example, involve a nationwide system of tradable water rights. Such a mechanism is commonly used in a variety of other contexts, such as land.

incidental benefit is that where this results in greater use of coal or imported LNG – despite any carbon tax – electricity supply security would be enhanced, given the diminished reliance on volatile hydro inflows.

### *Other Investment Issues*

While the electricity reforms have placed the task of signalling the need for new investments, and providing the incentives and funding for those investments, in the hands of market mechanisms and players, significant challenges remain. Aside from the issue that the “easy” generation projects have already been undertaken (and these were often challenging and expensive enough, given New Zealand’s topology), and that fuel sources are either unpopular (i.e. coal) or becoming scarce, prospective generation investors face a raft of risks. Under existing RMA provisions, resource consents expire after a fixed period and so any investor must factor the possibility of consent loss or new restrictions being imposed before the end of their investment’s economic life.<sup>14</sup> These uncertainties are compounded when government demonstrates it is willing to change the relevant rules on an *ad hoc* basis should circumstances, of a wide variety, change.

Other risks include the possibility of future policy changes that diminish the value of, or even strand, long-term sector investments. Such might be the fate of generation technologies currently receiving official favour because of their perceived environmental or other advantages, particularly when such technologies are not inherently economic.<sup>15</sup> The advantages legislators give they can easily take away. Uncertainties created by major policy changes or reversals can have important effects on investors’ perceptions as to the security of their property rights and hence their capacity to secure a return on long-term investment. The 1998 reforms forcing ownership separation between distribution and other activities are a significant example in this regard. Changes in regulatory policy can have the same effect, not just with the introduction of new regulatory rules (e.g. price caps) but also with the possibility of unpredictable and adverse changes in the way regulations are implemented over time.<sup>16</sup> But still the single greatest risk is almost surely the future of grid investment and pricing – a matter now in the hands of the Electricity Commission (see below).

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<sup>14</sup> Contact Energy is currently facing opposition to its consent renewal application to access geothermal resources because of allegations that its existing usage has caused subsidence and damage to nearby homes. Hydro generators face opposition from recreational users, irrigators, Maori, and environmentalists when applying for renewed river consents. In the US, proponents of wind farms soon became their opponents at consent renewals because of the significant number of birds killed by the turbines – a “terrestrial Exxon Valdez every year” (“Deadly for Birds”, *Dominion Post*, 18 December 2003).

<sup>15</sup> Imagine the fate of wind farms, for example, if technologies to use coal for hydrogen fuel cells and/or to “scrub” carbon oxides should become cost-effective.

<sup>16</sup> Risks in this regard relate to the possible regulation of energy prices, or the assumption by the Electricity Commission of functions currently the responsibility of the Commerce Commission. Recent moves to empower the Electricity Commission to, for example, require generators to offer a fixed proportion of their output via hedge contracts will also change the risk-profile of generation investments, as would any future changes to such powers.

The incentive for industry participants to undertake significant long-term investments hinges on whether they foresee the prospect of adequate return from doing so – given that electricity prices sufficiently and frequently attain the level required to fund them – and on their capacity to manage the risks of undertaking that investment.<sup>17</sup> The greater the risks, especially those beyond their control, the less attractive the investment proposition. Even where investors face significant investment costs, these can be less determinative in the investment decision than the risk of changes to the rules expected to apply over the typically long life of the investment. Minimising uncertainties, such as by providing a stable investment environment, must be a core government objective if private-sector firms or profit-motivated SOEs are to voluntarily commit their capital to long-term electricity-sector investments. The more the fate of the industry is centralised in the hands of an administrative decision-maker, the greater the opportunity for investment returns to be affected by changes beyond investors' control, or the greater the incentive for them to attempt to influence that party's decisions. Such centralisation has the capacity to shift competition from markets with transparent and certain rules into the murky and relatively unregulated realm of lobbying and securing political influence.

## SUPPLY SECURITY IN ELECTRICITY MARKETS

### *Dry-Winter Episodes Continue*

As noted in Chapter 6, winter power crises were commonplace prior to the reforms, and typically required a combination of voluntary and involuntary (through blackouts and other restrictions) power savings. The crises occurring since the reforms have successfully avoided the need for blackouts, and, since the advent of the wholesale electricity market in 1996, have been signalled months in advance through rising wholesale prices. Indeed, rapid and severe escalations in wholesale electricity prices have been the source of profits required to fund new generation investments (or the source of avoided costs to warrant demand-side investments to reduce demand).<sup>18</sup> Yet the perception remains that the reformed electricity sector is not capable of ensuring supply security, not least because there has not been a central agency responsible for ensuring security of supply – even though when there was, in the past, it couldn't and didn't.

<sup>17</sup> It should be noted that rising electricity prices are not a necessary condition for new generation investment. Technological improvements – such as those already observed with the introduction of combined-cycle gas turbines – can result in declining marginal production costs.

<sup>18</sup> In this light it can even be said that the concept of “supply security” is an oxymoron in the context of freely operating electricity markets. The concept has import in the context of the traditional, supply-focused centralised electricity system, in which electricity prices and demand are treated as exogenous, and demand regarded as interruptible irrespective of consumer preferences and welfare costs. However, where wholesale spot electricity prices instantaneously ensure that demand and supply are balanced throughout the day, supply will only be less than demand (i.e. that willing to bear the cost of scarce electricity) in the extreme cases where supply is zero, or where both supply and demand are completely price-inelastic (where demand exceeds supply at all prices). Where spot prices also provide short-lived but sizeable profits in times of tight supply, they encourage investments that ensure capacity keeps pace with users' willingness to pay for ongoing supply.

### *Market Reforms Failing to Provide Security?*

It is true that no one party in reformed electricity sectors is responsible for ensuring demand is met when supply is scarce. The obvious question to ask is, why should there be? Should all demand be met when supply is scarce? Arguably, the one and only reason that voluntary savings campaigns are required during winter crises is because many users are shielded against rising wholesale electricity prices through fixed-price supply or other hedge contracts. If prices don't move to ration scarce quantities, then other means of ensuring demand matches available supply are required.<sup>19</sup> But more to the point, not all demands are as critical, essential, valuable, or necessary as others. The fact that all electricity users are mindful of their power bill is sufficient to make the point – people might take longer showers if electricity is free; the fact that they don't in the face of positive power prices shows that electricity demand is discretionary, circumstance-dependent, and at least somewhat price-sensitive. It therefore requires a great leap to suggest that all electricity users – no matter how discretionary or flexible their demand – should even want guaranteed electricity supply during supply crises; and it is an even greater leap to suggest they are all willing to pay for such surety (and that such surety justifies its cost).

Wherein lies the nub. Perhaps the market reforms have failed to deliver supply security for all, in all circumstances, because this is not what is being sought by electricity users? Certainly some users are so dependent on supply security that they are willing to take steps – such as entering into hedge or other supply contracts, or investing in backup generation or demand management programmes – to ensure their demand is met. Whether or not the reforms have failed to deliver supply security cannot even be assessed by asking whether those seeking security of supply have been unable to do so, since this begs the question as to whether they have been willing to pay the true costs of this security (such as managing interruptible load or entering into long-term hedge contracts). Historically, supply security to essential services such as hospitals has been maintained either by other users bearing the risk of blackout, irrespective of whether such “non-essential” users have been willing or able to bear the costs of blackout, or through backup self-generation. The reformed electricity market has made the costs of security more transparent (i.e. through increased wholesale prices leading up to and during crises), which has signalled to those requiring security the value of investing in the necessary arrangements.<sup>20</sup> It might be said that the reformed electricity market has failed to ensure supply security when all those willing and able to pay the premium required to achieve this have done so and yet their demands have still not been met. But to date this does not appear to have been the case. As mentioned in Chapter 6, shifting dry-year risks to those able to best manage them is economically desirable.

<sup>19</sup> And in such circumstances, argue Joskow and Tirole (2004b), rationing can be socially optimal.

<sup>20</sup> It has also provided a measure of the opportunity cost of water, thereby signalling to other water users the cost of its alternative use. If tradable water rights were available, their price should expect to be correlated with electricity prices; and hydro generators and other water users would have an opportunity to engage in mutually beneficial trades (e.g. farmers foregoing irrigation in dry winters to sacrifice agricultural production in favour of selling water rights at high prices to hydro generators).

*Reserve Generation*

In this light the Electricity Commission's task of contracting for reserve generation (and/or interruptible load) can be regarded as a "one-size-fits-all" solution to a problem not equally shared by all electricity users. The fact that it includes contracting for interruptible load is clearly useful, since discretionary demands are then identified, but the question then becomes whether this central agency does so at the right price, since all electricity users bear the costs of its supply security arrangements through an energy tax.<sup>21</sup> Contracting for reserve generation is more problematic, for two reasons. Firstly, it creates a gaming/moral hazard problem (why conserve when there is reserve generation in place, or why hold generation in reserve if the political risk of dry-year supply shortages will rest with government's new Electricity Commission?). Secondly, it creates a cap – however soft or hard – on wholesale prices, thereby blunting the price signals to generators to elicit the new generation that market players are otherwise indicating they are willing to fund. The fact that most electricity consumers are apparently prepared to pay a premium in their electricity price to avoid the volatility in wholesale electricity prices suggests that they have a measure of preference for supply security (if only short term), or alternatively that they simply don't like variations in their power bills. Does the fact that they do not also pay a premium for long-term supply security suggest the market has failed to deliver them something they want, or does it simply reflect consumer preferences?

*"Public Goods" and "Market Failure"*

To suggest that market-wide long-term reserve generation is required (and an energy levy the best way to fund this) is to suggest that supply security is a "public good". Hence the traditional rationale in New Zealand for centralised state generation investments to provide "adequate supplies of electricity . . . at lowest practicable cost".<sup>22</sup> While in the short term such supply security might be argued to be so – affecting, as it does, real-time grid security that does often suffer from "public good" characteristics (by design if not inherently) – and while other consumers cannot be precluded from using reserve supplies contracted for by others on an interconnected grid, those seeking longer-term supply security are not without private solutions. Uninterruptible power supplies for small business users are already readily available. Individual household-level gas-powered electric turbine technology has been developed locally and is being exported. Larger or more vulnerable users (i.e. industrials, hospitals) have long had the option of self-generation, particularly where their processes use much heat and are thus amenable to co-generation or combined heat and power. The reforms have offered financial rewards, for users willing or able to exercise demand flexibility and/or to contract for interruptible load.

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<sup>21</sup> Effectively the Commission is being required to simulate a market mechanism for securing interruptible load – a function ably provided by power exchanges – but assumes all customers are prepared to pay for that interruptible load to ensure supply security instead of requiring those who want it to pay the cost of it.

<sup>22</sup> One of the purposes of the old Ministry of Energy under the Electricity Act (1968), as amended. See the summary in Chapter 8.

The reformed electricity sector allows for a wide range of possible solutions, but also places the onus on market participants – particularly those bearing the greatest costs of supply interruptions – to take out their own insurance rather than expect all other electricity users to provide it for them, thereby ensuring that those who truly value uninterrupted power supply bear the costs of the required investments.<sup>23</sup> A danger with centralised administrative solutions funded by industry levies is that centralisation shifts the burden of finding solutions away from those who naturally should bear them in favour of lobbying and securing cross-subsidies.

Indeed, at the heart of the ongoing international debate about the efficacy of liberalised electricity systems in ensuring ongoing security of supply is the question of “market failure”. Meade (2005) summarises the theory and evidence, showing that freely operating energy-only electricity markets can be expected to result in sufficient capacity investment to maintain system reliability and adequacy. He surveys the arguments for why such markets might fail in practice, noting that in most instances the failures attributed to electricity markets are in fact the result of poor market design or regulation. A striking example of this is the imposition of electricity price caps ostensibly to avert abuse of generator market power, which in practice eliminate the price signals necessary to elicit generation investments and demand savings. Additionally, theoretical arguments for longer-term supply security being a “public good” are shown to be misplaced, in that supply security lacks one of the key characteristics of such goods – namely non-rivalness (since one person’s provision or use of reserve capacity affects that of others). Even if it did not, the mere fact of a “public good” does not preclude private provision or necessitate state provision of that good – private, commercial free-to-air radio broadcasts being an obvious example.<sup>24</sup>

#### *Capacity Mechanisms and Alternatives Supporting Supply Security*

Despite theory and evidence supporting the efficacy of market-provision of supply security, various capacity mechanisms, surveyed in Meade (2005), have been proposed and in many cases adopted to compensate for regulatory distortions of price signals and other perceived market failings. These include installed capacity (or ICAP) markets,

<sup>23</sup> Contemporary “engineering school” advocates of centralised generation investment continue to argue in terms of the average cost of extra generation required for supply security to all consumers, rather than the varying costs borne by different consumers. Leyland (2003), for example, states that “the additional capacity we need, spread over all consumers, would be in the region of 0.2 cents/kWh”. Government has argued similarly regarding the Electricity Commission’s contract for reserve generation, suggesting households face an extra 0.5 cents/kWh to fund this insurance. Just as the total cost of household electricity purchases represents a small fraction of their weekly expenditure, the average burden of imposed insurance is also small. The overall welfare impacts can be large, however, and such compulsory universal insurance necessarily gives rise to issues of strategic gaming.

<sup>24</sup> Where goods are non-exclusive but rivalrous (e.g. longer-term supply security), they are better classified as common pool resources. Ostrom (2000) cites evidence that mechanisms for the private provision of such resources are common, but can often be crowded out by public provision. As for many true “public goods”, state provision is not in this case necessary to ensure their supply (nor is it guaranteed to do so).

capacity payments, operating reserves or planning reserves (or requirements), options-based schemes (such as virtual power plants, or VPPs), and capacity subscriptions with load-limiting devices (LLDs).

Such mechanisms often have the appearance of engineering solutions dressed in economic clothing. This is not least because the basic parameters of such schemes are often determined administratively (based on engineering considerations not dissimilar to those dominating industry planning before the reforms). They can distort investment signals and crowd out private capacity investment in favour of state/regulator investment. In some cases they even exacerbate the market power that first prompts the imposition of price caps – and ironically capacity mechanisms are often intended to remedy the distortions of such caps. Meade (2005) argues that such institutional arrangements are inferior to improvements in demand-side participation in electricity markets. This is especially so when combined with the vertical integration of generation and energy retailing, and some tolerance of generator market power, both of which increase the likelihood of capacity investment and hence supply security.

A promising example of further means to improve the market provision of electricity supply security is Doorman's (2003) suggestion of load-limiting fuses being installed by consumers who then subscribe for their preferred level of capacity. System operators can trigger those fuses in times of tight supply – much like the use of ripple control in New Zealand to curtail electric hot-water heating, for those who opt for pricing plans with this provision, and interruptible load contracted for by Transpower as system operator. Such measures internalise the price of security to consumers, making such security a decidedly private good capable of market pricing and provision. Given that such mechanisms already exist in New Zealand, there is reason to expect that security of supply would be elicited under normal market operation.

Doubt about this conclusion arises where environmental-consent processes and other institutional constraints (such as insecure and non-tradable water rights) fetter the operation of otherwise functional markets. Given also the implicit wholesale electricity price cap under New Zealand's reserve generation scheme, and the lack of a formal capacity mechanism beyond that scheme, it can be predicted that private capacity investments will find themselves crowded out by regulated investment. Such a result is unnecessary, given the aim of supply security. It also offers false hope, in that regulated investments will be just as subject to the variability in New Zealand's hydro inflows and lack of hydro storage as private ones. Any depression of electricity prices and false sense of security that result from the reserve-generation scheme will encourage electricity consumption rather than energy-efficiency investments, conservation and the development of self/backup generation.

## GRID INVESTMENT

Back to the crossroad. In general terms, the greater the grid capacity the less likely that grid congestion causes the network to fractionate or “regionalise” into less competitive sub-networks (i.e. those in which a reduced number of generators vie for available demand). At the same time, increased grid capacity reduces any incentive for generators with plant across regions to engage in strategic behaviour to create grid congestion so as to curb competing generation. In short, if there was money to burn (and no other – e.g. environmental – constraints on grid expansion), then a tempting strategy would be to invest in considerable grid overcapacity both as a means to allow for future demand and generation growth and to facilitate nationwide generation competition. If only life were so simple.

### *Transpower’s Changing Investment Incentives*

The reality is that grid investments are costly, irreversible and long-lived. They tend to suffer (in real time, at least) the externality, public good and natural monopoly distinctions of AC networks described in Chapter 2, and are subject to the raft of constraints faced by other major investments with social, economic, political, and environmental impacts. If the government does not have an open chequebook for grid investment – with all its “national interest” objectives in addition to any economic benefits it derives from ownership of Transpower (i.e. taxes, dividends, and, maybe one day, the prospect of realised capital gains) – it is probably safe to assume that neither Transpower nor industry does either (and on welfare grounds nor should these). In the reformed electricity sector, grid expansions must proceed on their merits – but from whose perspective? Transpower does not profit from congestion rents (these are rebated to distribution companies and other grid-connected parties), and it risks bypass by distributed generation, gas-bypass and demand management if constraints should prove sufficiently binding and costly. Prior to its investment and pricing policies being subsumed by the Electricity Commission, it therefore had an incentive to invest in grid expansion to preserve its commercial return. It was not free to do so, however, being subject (among other things) to price control by the Commerce Commission – which also attenuated investment. Transpower’s incentives are now highly restricted (with profit gains to be made on operational efficiencies alone), given the pricing and investment policies it must implement. The Electricity Commission’s incentives to determine optimal transmission investments, without effective market-based investment mechanisms, are, by contrast, purely bureaucratic.

### *Non-Transpower/Merchant Grid Investment*

To avoid the risk of new investments – particularly those of a more customer-specific nature – being stranded, Transpower has historically been able to contract with such customers to secure its return over the life of the investment. Its ability to do so is potentially a reflection of market power, although it can be a necessary

part of commerce.<sup>25</sup> The effect of such an arrangement is that the risks of the new investment and ultimately its cost are borne by the customer, even though Transpower is responsible for undertaking and managing the investment. This begs the question – why not have parties other than Transpower take responsibility for grid expansions? Transpower or some other contestable system operator could ultimately manage the grid, bearing in mind the “free-riding” and other issues arising in electricity networks already discussed.

This, of course, is the holy grail of reformed electricity sectors. Can the problems of scale economies, public-good characteristics and network externalities be accommodated within economic constructs so as to facilitate decentralised market-based grid investments, or are we stuck with the traditional model of monopoly grid provision (regulated or otherwise) in which there is centralised determination of grid characteristics and hence market-wide competitive topology? Attempts to create property rights over a grid that is otherwise a “commons” include the development of financial transmission rights (FTRs) and transmission congestion contracts (TCCs). These were introduced in Chapter 2 and discussed further in Chapter 9. Such instruments go some way towards allowing individual grid users or investors to protect themselves against the costs of grid congestion and thereby preserve some benefit from grid investment even when other grid users “free-ride” on that investment and reintroduce constraints. They do so imperfectly, however, and, as discussed in Chapter 9, can either exacerbate or ameliorate existing generator (or consumer) market power depending on the circumstances. A proposal by Transpower for the introduction of FTRs in New Zealand enjoys ongoing support, but is still not yet in place.

Even with FTRs of sufficient attraction to third-party grid investors, the requirements for coordinated grid management are not eliminated. Grid investment proposals will have grid-wide effects beyond their rated capacity, in terms of both overall grid capacity and opportunities for gaming or market power. This suggests an ongoing grid “watch-dog” role if not that of centralised “grid-owner/master/planner”. According to Joskow and Tirole (2004a), the merchant-transmission model offers an effective example of decentralised transmission planning, albeit one which breaks down in the presence of certain current institutional and technical constraints. They conclude that merchant-transmission investment cannot be relied on alone to stimulate efficient transmission investment.

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<sup>25</sup> Any non-fungible investment, network or otherwise, under competitive circumstances or not, is at risk of “stranding” – see, for example, Evans and Guthrie (2003). In cases where investors are not in the position of “locking-in” customers to guarantee that the cost of investment is ultimately recovered, they instead may maximise the flexibility of their investments (e.g. so they can be redeployed if needed be at some higher cost) and bear the risk of stranding, making sure they are sufficiently rewarded for some level of expected stranding risk. Investment is thus affected by the process of controlling regulated firms’ prices.

### *Changing Centralisation of Grid Investment*

So, if New Zealand does not have FTRs or their equivalent to encourage third-party grid investments that reflect decentralised market-based preferences, or if merchant transmission is not feasible, does this mean Transpower – or now the Electricity Commission since it has assumed responsibility for Transpower’s pricing and investment policies (with the Commerce Commission having final oversight of prices)<sup>26</sup> – should ultimately decide how, when and at whose expense grid investments should be undertaken? While this is not identical to the pre-reform model, in which vertically integrated state-run generation and transmission were managed centrally and administratively, it shares some similarities.

A “wise” Electricity Commission must weigh competing demands for new grid capacity, determine how best to allocate common costs among grid users, and otherwise determine a pricing policy that aligns (as best as can be achieved) with the costs and benefits of grid usage. – just like a local council trying to decide who gets a new recreation centre and on what terms. Where this alternative departs from the pre-reform model is that it involves consultation regarding proposed expansions with industry participants who will (in some cases directly) bear the cost of expansions. Those participants also now include profit-motivated and competing generators, and a reduced number of distribution companies (with reformed ownership and incentives, and price regulation). Because of the reforms, these parties and other grid users are better able to either fund grid investments or to explore alternatives (such as locating new generation closer to load, investing in demand management, or developing lines companies that compete with the grid at the margins). In effect the Electricity Commission will be required to create a *de facto* market for new transmission capacity under rules of its making – but without the industry and grid knowledge (or incentives) enjoyed by the hitherto operator of such a market, Transpower.

### *Alternative Strategy to Simplify Grid Investment*

An alternative technical strategy, suggested by Loehr (2001) and echoed in Van Doren and Taylor (2004), is to make the physics of electricity grids more amenable to the economics instead of trying to achieve the reverse (e.g. via FTRs and TCCs). Van Doren and Taylor point out that expanding the grid has many desirable features, but at its heart simply exacerbates the problem of the “commons” associated with existing AC networks – a problem that FTRs and TCCs attempt to resolve. Instead they suggest that AC networks be broken into smaller sub-networks interconnected with high-voltage direct-current (HVDC) links, not unlike the way in which the north and south

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<sup>26</sup> The Commerce Commission has utilised rate-of-return regulation based upon the replacement cost of grid assets optimally designed for current and immediate demand. It entails *ex post* recovery (payment) of deficits (surpluses) engendered over a threshold profit level: the resultant volatility in charges has been born by grid customers. The optimisation has limited investment in the grid because of the lack of reward it provides for investment in advance of demand and for covering the cost of stranding of assets.

of New Zealand's existing network is interconnected via the inter-island HVDC link. One electricity industry commentator of an engineering bent has already suggested a variation on this in the form of a 2,000 MW "electricity motorway" between major South Island generation and dominant and growing Auckland electricity demand.<sup>27</sup>

The advantages suggested for such an approach are that it diminishes the grid-wide implications of failure or constraint in any one part of the grid – effectively localising such failures – meaning the grid can then be operated more independently within each interconnected region. Not only does this mean that sub-grids can potentially be "run harder" (i.e. by increasing the likelihood of meeting the "N-1" grid-security operating standard), which increases the effective capacity of existing grid assets; it also facilitates grid expansions by making their effects more localised (thereby also mitigating problems of free-riding on grid investments).<sup>28</sup> It even becomes more possible to schedule transactions over particular HVDC lines, increasing the ability to match contractual and physical flows.<sup>29</sup> The problem of coordination is relieved, and the rationale or need for centralised administration diminished. And all this while maintaining the benefits of nationwide competition in generation and a national electricity market.<sup>30</sup>

Establishing such HVDC interconnections is expensive – hence the preference for cheaper AC networks when grids are first developed – but it is possible that the benefits they bring in terms of increasing effective grid capacity and reducing the frequency and impact of outages, and also in facilitating market-driven and/or competition-enhancing grid investments, will be sufficient to justify their adoption.<sup>31</sup> It is impossible *a priori* to say whether the costs outweigh the benefits; and the problem remains of identifying who should pay for any "public benefit" (as opposed to "capturable" private gain) that such a reconfiguration might deliver, and who most naturally should contemplate its instigation. Of itself, this suggests that much is to be gained by resolving such questions at the decentralised level rather than relying on a wise planner to fortuitously know how to identify (let alone arrive at) the optimal solution.

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<sup>27</sup> "Power 'Motorway' Floated", *Dominion Post*, 2 March 2004. Such a link bypasses the existing grid and its occasional constraints, and is predicted to relieve the need for its major planned upgrade elsewhere while seeing Auckland demand is met.

<sup>28</sup> Of course, it can do so possibly at the expense of creating bottlenecks through the HVDC interconnections, but such bottlenecks are likely to be more amenable to expansions than a fully integrated AC network.

<sup>29</sup> It is the inability to do this over AC networks that makes the "commons" problem of AC networks so difficult to solve with economic constructs.

<sup>30</sup> Warrick (2005) notes the similar potential of technological improvements in grid switching. With solid-state rather than physical switching, similar increases in effective grid capacity using existing components can be expected.

<sup>31</sup> The importance of shifting the risks of grid investments to those seeking and benefiting from them is potentially added to by the possibility of significant technological change in transmission. For many decades the fundamentals of transmission have been relatively unchanged, but the advent of superconductor technology is one possible advance that might dramatically change both its physics and economics, thereby adding to the risk of stranding.

### *Contrast with Demand Management and Distributed Generation*

It is against such alternatives that the current government policy favouring investments in demand management and distributed generation (particularly renewables-based generation) ought to be weighed.<sup>32</sup> Where economic generation can be located nearer to load (subject to environmental and community concerns, etc) it is clearly a sensible option. To suggest that this is a long-term alternative to grid expansion ignores the risks of electricity market regionalisation and reduced generator and energy retailer competition, so the importance of the current long-term upgrade of the grid should not be lost in the current preference for distributed generation.

### *Using Ownership to Support Grid Investment*

The preceding implies that it is necessary to have some level of coordination among investments in demand management, generation, transmission, and distribution – the critical questions being in what form and by whom. Such coordination is the key function of markets where actors make their own decisions; yet due to the management of security of real-time supply and the difficulty of specifying and enforcing property rights on AC grids, at least some central coordination is currently required. Experience such as that in Europe demonstrates that self-dispatch and decentralised balancing responsibilities can form an important part of such central coordination. The advantages of decentralised decision-making is such that centralised control is best limited to that which is essential for operation and investment relating to the system as a whole.

Governance relating to the operations of the centralised component is critical for its success. As mentioned in Chapter 9, the present New Zealand system does not make for lines of accountability or assurance in a stable operating environment. The objectives of the state-held entities, particularly those of Transpower, are mixed, rendering responsibilities and effects of regulation problematical; and industry-wide regulation lies with a body that is tightly linked to the government of the day and that is responsible for operational aspects and particular outcomes – not unlike New Zealand’s central planners of old. To one side sits the Commerce Commission with price responsibilities. The two solutions suggested in Chapter 9 – customer or investor ownership, as opposed to state ownership – seem worthy of reviewing here.

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<sup>32</sup> Wind farms are a limited means to satisfy new electricity demand. Aside from the problems of new transmission requirements to transport energy to load, and the often-heated opposition to the environmental impacts of wind farms (e.g. scenic degradation and noise), they typically can only operate 40% of the time (i.e. as the wind blows, and not too strongly), and because of wind fluctuations can raise the cost of grid security. The maximum possible wind-power capacity in New Zealand has been estimated to be in the vicinity of 1,000 – 1,500 MW (“Solution to Power Needs is Blowing in the Wind”, *New Zealand Herald*, 8 March 2004). This compares with an estimated 1,000 – 2,000 MW of potential new economic and environmentally tolerable hydro-generation capacity (Sinclair Knight Merz (2003)), which represents considerably higher effective capacity given hydro plant can be run more in the order of 90%+ of the time (Ministry of Economic Development (2003)) where hydro reserves allow.

*Customer Ownership to Internalise Investment Incentives and Coordination*

The model of “club” ownership of transmission by grid-connected parties arguably mitigates a number of concerns regarding transmission market power, particularly with rationalisation of distribution company ownership and governance. The need for price caps or other forms of regulation for transmission then becomes moot, with any benefits of transmission’s natural monopoly (to the extent they are enjoyed) being enjoyed by those suffering the burden of that monopoly. This resembles the model suggested for Transpower as far back as 1989 (see Chapter 5). A variation on that model might also offer advantages in resolving the problems of encouraging and coordinating grid investment, as an alternative to centralised or other decentralised solutions. In short, the problems of encouraging third-party investment in the grid – insofar as this is considered a policy objective – might be ameliorated by transforming the relevant third parties into the first person.

The premise of this approach is that the parties most adversely affected by constraints in the grid are grid off-takers. It must be acknowledged that grid-injectors (i.e. generators) can also be adversely affected by grid congestion – although there are strong arguments for at least some generators to prefer congestion as a means of enhancing market power; but, to the extent that this is true, the consequences are likely to be of a lower order than for off-takers.<sup>33</sup> Hence the parties with the strongest incentives to relieve transmission congestion are off-takers (in the case of distribution companies, the off-takers are their customers, since grid charges are simply passed on through distribution charges). At present they are not, as a class, in a position to control grid investment, but instead must contract with Transpower on terms it finds agreeable to undertake grid expansions and now also must persuade the new Electricity Commission of the merits of competing grid-expansion proposals.

If a “club” of grid off-takers were to own the grid, the coordination problem and costs of grid investments would rest with those having the greatest interest in seeing them ameliorated. Certainly the issue of common-cost allocation would remain a significant issue to resolve, but, in the face of necessary grid expansions, the costs of failing to resolve those questions in a principled and non-opportunistic fashion that protects the long-term interests of all concerned are borne by those in the best position to resolve them. Under this approach generators might fear that grid-injector connection charges

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<sup>33</sup> This is analogous to exporters suffering adverse consequences from increases in shipping costs. The distinction in the electricity context arises from the relative price-inelasticity of demand compared with supply. If grid congestion is thought of as a form of “tax” on electricity sales, then conventional supply and demand analysis predicts that both suppliers and consumers suffer from its imposition: suppliers in the form of reduced quantity and pre-tax price; consumers in the form of increased post-tax prices at lower quantity. The party with the relatively lower price-elasticity bears the greater burden of the tax: in the extreme, with one party completely price-inelastic (as is often suggested for electricity demand), it is that party which bears all of the tax burden, with quantity unchanged but with prices increased by the amount of the tax. Thus, unless and until electricity demand becomes considerably more price-elastic, it should be predicted that transmission congestion is a cost borne predominantly by off-takers, not generators.

would be raised monopolistically by off-takers, but then off-takers as a class bear the costs of losing generation capacity as a consequence.<sup>34</sup>

Transmission investments would be determined and funded under the governance of the “club”. While competition for capital and differing regional (or customer class) priorities might create divergences of interests, at least no off-taker would have an incentive to undertake inefficient investments (since they ultimately bear all or at least some of the costs of that inefficiency). Indeed, if a suitable form of FTR, TCC or alternative instrument could be devised for allocation to grid investors – and/or the HVDC-interconnected decomposition of the AC network implemented – third parties, including generators, might be permitted to undertake grid expansions, but subject to the approval of all off-takers, and with the consequences of any inefficient investments being at least partly internalised. In effect this approach creates a monopoly transmission and distribution network owned by those bearing the cost of that monopoly, contracting with an oligopolistic but at least partly competitive and privately owned generation sector now deprived of an opportunity to undertake inefficient grid investments.

Such an approach has the advantage over the new Electricity Commission model in that the costs of transmission constraints and benefits of grid investment are borne by those with the best information and capacity to determine and undertake suitable investments. Under the Electricity Commission model the “wise planner” gets to determine grid investments but has inferior information, resources and incentives to do so. It must be acknowledged that this “club” approach does not solve problems of grid-investment strategy and pricing policy: it merely shifts those problems to another forum. The suggested benefit of this approach is that it places the decision problem where the resources and incentives (and costs of indecision) are strongest, so that these problems are resolved in a principled and time-consistent fashion (i.e. no short-term gaming of the regulator for narrow advantage here). It simultaneously diminishes the rationale or need for the regulation of transmission and distribution, meaning that regulatory distortions and direct costs can be reduced.

### *Regulated Investor Ownership*

The second ownership alternative that may facilitate and support grid investment is, in various forms, represented in the approach of countries such as the UK, Australia and Western Europe more generally.<sup>35</sup> It is to obtain the enterprise performance benefits of private ownership and to have a regulator that is at arm’s length from government. This regulator has the responsibility of approving and enforcing price control and investment plans on the grid owner, by means of a form of incentive regulation with reviews at defined and staged intervals. Such a structure enables consideration of generation and

<sup>34</sup> If this should prove not to be the case, it remains possible to impose price caps on grid-injector connection fees. This would more significantly reduce distortionary impacts and regulatory costs than would general caps on transmission charges.

<sup>35</sup> For a summary of the approaches of different countries see Henney (2002, Table 1).

demand-modification investments by others at the time grid investments are approved, and a governance structure for the grid that enables and enforces devices such as FTRs. Although regulation always shares, even clouds, accountability, the resultant system would have enterprises whose roles and objectives were well understood, leading to more effective regulation. Unlike the Electricity Commission, the regulatory body would not have market participant, operator, regulator, and specific outcome roles; instead it would have the simpler, less-confused objective of regulator. Such a configuration continues to require external coordination of transmission and generation investment (and demand-management investment), in the absence of customer ownership of transmission, but it offers efficiency and incentive advantages relative to the models historically and more recently adopted in New Zealand.

## BREAKING THE IMPASSE BETWEEN GRID AND GENERATION INVESTMENT

### *The Strategic Problem*

Generation and transmission are substitutes (as are demand-side measures), but in some cases complements, so changes in one affect the other. These interdependencies – and the problems they pose for investments – are clearly telling once the large, long-lived and irreversible nature of generation and grid investments is considered. A grid expansion can be made redundant if new generation is built downstream; similarly, generation can become uneconomic if new transmission capacity is installed, enabling cheaper remote generation to instead supply demand. Which should invest first, and where, pose simultaneous decisions for transmission and generation, and do so where competition is favoured over coordination when those decisions arise in a restructured electricity system. Where grid and generation investments are not coordinated by some formal/public or informal/private means, risks of stranding and costs of transactions can be so large that investment overall is inhibited and inefficient investments take place.

### *Regulated Investor Ownership as a Solution*

The regulated investor ownership approach to grid investment, discussed above, is one way of breaking the simultaneity problem confronting grid and generation investment. By regulating grid investment and transmission pricing, the evolving grid can be taken as given for generation investors to plan around, and for the regulated grid owner to implement at the least cost (assuming incentive regulation). The grid-investment plan itself will recognise likely generation plans and responses, as is the case in any leadership game (meaning strategic behaviour will be reduced but not eliminated under this approach). The grid owner enjoys the certainty of regulated prices that support investment; and generation investors make their plans based on a committed grid investment programme, which reduces their vulnerability to stranding. In this case the risk of inefficient investments resulting from poor coordination is reduced, but at

the risk of misdirected or misapplied regulation producing inefficient grid investments and pricing.

Furthermore, if regulated grid prices enable grid-investment costs to be recovered with certainty – in effect affording the grid owner a right to “tax” grid users for new investments – then the advantage this approach affords the grid owner ought to be tempered by making that right to “tax” contestable. In practice that would involve alternatives to proposed grid investments being invited and compared by the regulator in terms of their ultimate system effects, with the right to “tax” being awarded to the most efficient alternative (whether generation, demand-side, or grid-based). Even with a contestable right to “tax” the grid owner is likely to enjoy a first-mover advantage relative to generation investors, but not at the expense of overall efficiency.

### *The “Club” Model as a Solution*

The “club” ownership model of the grid, also discussed above, is another alternative through which the simultaneity problem can be addressed. In this case any adverse consequences of regulating grid investment and pricing can be averted, with off-takers having a natural hedge against grid over-pricing and an incentive to coordinate with generation investors to achieve efficient investments. Voluntary incentives for coordination encourage investment leadership by the grid – to, in effect, tie its own hands and commit to not opportunistically strand generation by new grid investment. Where the “club”-owned grid did make opportunistic investments that stranded generation, any trust it had developed with generators would be broken, encouraging generation investors to adopt more risk-hedged investment plans, with likely less efficient investments as a consequence. Once again, by internalising the costs of failing to coordinate with generation or sullyng its own reputation by opportunistic behaviour, this ownership model ensures that efficient behaviour is rewarded and opportunistic behaviour punished. Since grid and generation investments are long-lived, and both generators and grid owners are assured of repeated interactions, coordination is likely to evolve and relational contracts between the parties to develop. If the economic costs of “club” grid ownership are less (more) than the economic costs of regulating investor grid ownership, then the former ownership model should result in more (less) efficient grid and generation investments than the latter.

## CONCLUSION

With the recent and unexpected downward revision of available gas reserves in the Maui gas field, there is increasing concern (quite rightly) that New Zealand is vulnerable to more frequent winter power supply shortages. New generation waiting in the wings indicates the nature of the investment problem in the reformed electricity sector. Generation and transmission investments in the last decade have not been subject to the raft of competing interests and constraints now limiting the rate and

scope of new investments: in previous decades investment had been implemented by government with scant regard to cost. Many of the current constraints are a consequence of government policy unrelated to the electricity sector and its reform. They include the Resource Management Act and Kyoto protocol, and regulatory mechanisms. That new generation in the 1990s was at a level commensurate with that of the preceding two pre-reform decades should offer reassurance that the market has not in fact failed, but delivered much in the face of great challenges.

To suggest that the reforms have still not delivered enough – in that the risk of winter shortages has increased – is to ignore history and mis-state the objective. Regular winter shortages were a common feature of the sector pre-reform, and they were weathered with much harsher measures than those experienced since the reforms. In any event it is a mistake to suggest that all consumers wish to have all of their electricity demands met all the time, particularly in times of shortage. If this was a factor of electricity planning in New Zealand pre-reform it failed, and it resulted in wasteful investment in expensive over-capacity – over-capacity which even then did not guarantee supply security.

In the reformed electricity sector, investors in generation take their cues from rising wholesale electricity prices and transmission congestion as to when, where, how, and what to invest. If electricity prices should systematically rise above the long-run marginal costs of new generation, then it might be suggested that the market has failed to deliver required new generation – but so far this is not the case. Where wholesale electricity prices have soared – during winter crises or major outages – signals have been sent regarding the economic viability of short-term peaking plant. That the new Electricity Commission (initially through the Ministry of Economic Development) has contracted for reserve generation and thereby imposed a cap on wholesale electricity prices creates gaming problems in the form of reduced incentives to conserve energy and create the very new generation required to avoid the need for reserve generation in the first place. The fact that this represents a one-size-fits-all imposed insurance policy funded by all electricity users via an energy levy also diminishes the incentive for those users most exposed to wholesale price increases and supply shortages to take steps to fix their own problems, provides them with wealth transfers, and makes the issues less transparent.

To the extent that government policy seeks to facilitate third-party and/or SOE investment in new generation to provide a desired level of supply security, less regard needs to be had to the shape of the reformed electricity sector and more to the wider policy and institutional environment. Government would seem, at least in part, to acknowledge this, in that it is amending the RMA so that greater priority be given to renewable energy projects such as small hydro schemes. Conservation and environmental policy remains a potential obstacle, however, and any specific measures to encourage generation investment must be supported by a general institutional

framework that provides certainty as to policy, regulation, governance, and property rights so that investors can be confident of recovering the costs of their large-scale, long-term and otherwise sunk investments.

Transmission investment remains key to determining the long-term competitive topology of the New Zealand electricity system. A mis-step now in the long-term upgrade of the transmission grid has the potential to hinder market-based and competition-encouraging investment elsewhere in the sector. Various alternatives are available to broaden the options for future sector reform and enhancement of competition, but at present New Zealand does not appear to be paying these much regard, instead adopting a hybrid of the current model and more centralised administration. The options of a “club” model for Transpower ownership, or the publicly owned but regulated alternative, are unlikely to find any favour in the current environment. This is despite their potential for bringing us closer to an effective means of resolving the thorny transmission pricing and investment problems, and for diminishing the need for, or to at least sharply focus, the newly imposed heavy-handed regulation.

