

# ALTERNATING CURRENTS OR COUNTER-REVOLUTION?

Contemporary Electricity Reform in New Zealand



Lewis T Evans and Richard B Meade

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# Alternating Currents or Counter-Revolution?

*Contemporary Electricity Reform in New Zealand*

Lewis T Evans and Richard B Meade

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As always, any errors or omissions belong to the authors. It should also be noted their views do not represent those of the institutions to which they belong.

This book is dedicated to our respective wives, Sharon and Sara.



## LEWIS EVANS

Lewis Evans is a professor of economics at Victoria University of Wellington and was the first executive director of the New Zealand Institute for the Study of Competition and Regulation Inc (ISCR). He has a PhD in economics from the University of Wisconsin-Madison. His research specialties are the economics of organisations and markets. He has published approximately 35 refereed articles in international and local economics journals and another 40 publications; and he has been a member of the editorial board of the US Journal of Economic Literature. Professor Evans is a lay member of the New Zealand High Court for matters of commerce and was a member of the Electricity Market Surveillance Committee of the New Zealand Electricity Market. He has consulted for companies and governmental organisations, including the Asian Development Bank and the RAND Corporation (a private policy institution in Los Angeles). He is a senior consultant for Charles River Associates (Asia Pacific) Limited. At ISCR he supervised research into aspects of the New Zealand electricity industry.

## RICHARD MEADE

Richard Meade is a research principal of ISCR, and as principal of Cognitus Advisory Services Limited advises clients on strategic and analytical problems drawing on the tools of economics, corporate finance and quantitative analysis. He also lectures in corporate finance, corporate governance and Maori/tribal governance at Victoria University of Wellington. Richard graduated from Victoria University with degrees in economics and finance, and statistics and operations research, in 1991. He worked for Credit Suisse First Boston in New Zealand from 1989 through to 1998, specialising in mergers and acquisitions, privatisations, company and derivative security valuation, and providing economic and corporate financial advice. While at CSFB he participated in electricity distribution company reorganisations; and he advised New Zealand's state-owned grid operator, Transpower, and generator, ECNZ, on cost of capital issues, and the State Government of Victoria on the privatisation of electricity generation assets. He previously worked for ECNZ's modelling group valuing small hydro generators. Since 1992 Richard has also contributed to governance developments in New Zealand, including the corporate reorganisation of listed corporate Fletcher Challenge, the design and valuation of performance-based executive compensation schemes, the development of tribal governance structures for the major South Island Maori tribe, Ngai Tahu, and the debate surrounding governance changes to leading New Zealand fishing company Sealord.

Comments or queries can be directed to Richard Meade at: [richard.meade@cognitus.co.nz](mailto:richard.meade@cognitus.co.nz).





## TABLE OF CONTENTS

<i>List of Tables, Figures and Boxes</i> .....	3
<i>Abbreviations</i> .....	7
<i>Map of New Zealand</i> .....	11
<i>Reform Timeline</i> .....	13
<b>1 The Power Game</b> .....	19
<b>2 Electricity and Electricity Markets</b> .....	31
<b>3 The New Zealand Electricity System</b> .....	63
<b>4 Survey of Selected Overseas Reforms</b> .....	117
<b>5 New Zealand’s Electricity Reform History</b> .....	133
<b>6 Coping With Crises</b> .....	167
<b>7 Demand-Side Participation</b> .....	187
<b>8 Decentralisation, Centralisation and Governance</b> .....	207
<b>9 Gaming, Market Power and Regulation</b> .....	239
<b>10 Investment</b> .....	283
<b>11 Whither New Zealand’s Reforms?</b> .....	309
<i>References</i> .....	317
<i>Detailed Contents</i> .....	337



## LIST OF TABLES, FIGURES AND BOXES

### TABLES

TABLE 2.1	Market Arrangements Compared .....	47
TABLE 3.1	1992 Hydro Storage and Inflow Volatility Compared .....	71
TABLE 3.2	Electricity Generation Process Efficiency .....	71
TABLE 3.3	Distribution Company Ownership .....	87
TABLE 3.4	Distribution Company Operating and Reliability Statistics 2004... ..	91
TABLE 3.5	Retailer/Generator Market Shares as at January 2003 .....	95
TABLE 5.1	Electricity Prices Before and After ECNZ Separation (\$/MWh).....	149

### FIGURES

FIGURE 1.1	Main Electricity Sector Actors in New Zealand.....	23
FIGURE 2.1	Equilibrium Changes with Demand Un/Responsive to Price.....	36
FIGURE 2.2	Price and Quantity Changes in the Short and Long Term .....	37
FIGURE 2.3	Price Separation Following Loss of Inter-Island HVDC Link .....	39
FIGURE 2.4	England and Wales Mean Electricity Prices and Costs 1990-2002.....	52
FIGURE 2.1.2	Stoft (2002) Scheme of Market Types.....	57
FIGURE 2.2.1	Coordination on the Waikato and Waitaki River Systems .....	60
FIGURE 3.1	Primary Energy Supply Shares 2003 .....	65
FIGURE 3.2	Energy Usage by Sector 2003 (%).....	65
FIGURE 3.3	Sector Energy Demand Shares by Energy Type 2003 (PJ) .....	66
FIGURE 3.4	Schematic of the New Zealand Electricity System.....	67
FIGURE 3.5	10+ MW Generation Capacity 2003 (MW) .....	68
FIGURE 3.6	Location of Major Generators .....	69
FIGURE 3.7	Generation Mix 1974-2003 (GWh).....	70
FIGURE 3.8	Mix of Generation Capacity by Major Generator 2003 (MW) .....	72
FIGURE 3.9	Operation of the Wholesale Electricity Market .....	73
FIGURE 3.10	Half-Hourly Pricing Process.....	74
FIGURE 3.11	Daily Average Prices (\$/MWh) and Hydro Storage (GWh) .....	75
FIGURE 3.12	Histograms of Daily Average Prices at Main Centres (\$/MWh).....	78

FIGURE 3.13	National Transmission Grid .....	79
FIGURE 3.14	Location of Major Supply and Demand .....	80
FIGURE 3.15	Main Transmission Constraints .....	81
FIGURE 3.16	HVDC Transfers 2001 and 2002 (GWh/Day).....	81
FIGURE 3.17	Average Transmission Charge (¢/kWh) 1991-2004.....	82
FIGURE 3.18	Loss and Constraint Rentals 1996-2004.....	83
FIGURE 3.19	Customer Interruptions 1991-2004 (System Minutes).....	84
FIGURE 3.20	Total Unplanned System Interruptions 1991-2004 .....	85
FIGURE 3.21	Distribution Companies as at 31 March 2004 .....	88
FIGURE 3.22	Adjusted ROI (%) vs. Line Charge (¢/kWh) for Year to 31 March 2003..	89
FIGURE 3.23	Distribution Company Rationalisation 1995-2003 .....	90
FIGURE 3.24	Nominal Average Line Charges 1994-2005 (¢/kWh).....	91
FIGURE 3.25	Real Average Line Charges 1994-2005 (¢/kWh) .....	92
FIGURE 3.26	Indexes of System Interruption Measures 1995-2004.....	92
FIGURE 3.27	Generator Market Shares (Years Ended).....	95
FIGURE 3.28	Consumption 1975-2003 (MWh).....	96
FIGURE 3.29	Annual Demand (MWh) and Customer Shares by Class 2003 .....	97
FIGURE 3.30	Average Consumption 1975-2003 (MWh/Customer) .....	97
FIGURE 3.31	Nominal Average Electricity Prices 1974-2003 (¢/kWh) .....	98
FIGURE 3.32	Real Average Electricity Prices 1974/1979-2003 (¢/kWh) .....	98
FIGURE 3.33	Proportion of OECD Countries having Cheaper Electricity than New Zealand 1981-2003.....	100
FIGURE 3.34	Returns to Government from Electricity Industry .....	100
FIGURE 3.35	Electricity Industry Sales Revenue 1987-2004 (\$m) .....	102
FIGURE 3.36	Electricity Industry Profits 1987-2003 (\$m).....	103
FIGURE 3.37	Returns to Investors from Electricity Industry .....	104
FIGURE 3.38	Electricity Industry Real Economic Rate of Return .....	105
FIGURE 3.39	Transpower's Target and Actual Accounting Rate of Profit.....	105
FIGURE 3.1.1	Generation and Demand Centres of Gravity .....	113
FIGURE 4.1	US Average Retail Price by State (1996, US¢/kWh).....	123
FIGURE 4.2	US Restructuring in California's Wake (as of February 2003)	125
FIGURE 4.3	European Generation Remains Mostly Concentrated (%) .....	130
FIGURE 4.4	European Markets Open to Competition (TWh, 2003) .....	130
FIGURE 5.1	Secondary Hedge Market Trading 1994-1996 (kWh) .....	142
FIGURE 5.2	The Early "Wholesale Market" .....	143
FIGURE 5.3	Wholesale Prices under Competing Generation 1996-2004.....	148

FIGURE 5.4	Customers Changing Electricity Supplier 2000-2005.....	153
FIGURE 5.5	Number of Retailers in Line Company Areas.....	154
FIGURE 5.6	Sequence of New Zealand's Structural Electricity Reforms.....	155
FIGURE 5.1.1	Wholesale Prices under Structural Change 1978-2003 (¢/kWh)	164
FIGURE 6.1	Lake Inflows in Major Catchments.....	171
FIGURE 6.2	2001 Electricity Supplied and Hydro Levels (GWh) and Spot Wholesale Prices (\$/GWh) .....	174
FIGURE 6.3	Hydro Storage Levels – 2003 vs 2001 and Average (GWh).....	178
FIGURE 7.1	Orion Energy Deliveries and Peak Demand 1984-2003.....	194
FIGURE 7.2	Average Weekly Household Expenditure by Income Type.....	201
FIGURE 8.1	Spectrum of Control Options.....	208
FIGURE 8.2	Real Electricity Prices 1945-1993 (1993 ¢/kWh) .....	210
FIGURE 8.1.1	De/Centralised Control in Socialist and Capitalist Systems	235
FIGURE 9.1	Welfare Loss With Gaming Under Uniform-Price Auctions.....	242
FIGURE 10.1	New Generation 1900-2002 (MW, 10+ MW).....	287

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## BOXES

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BOX 2.1	Link between Electricity and Water Markets .....	46
BOX 3.1	Energy Intensity Comparisons 1980-2002.....	64
BOX 3.2	Wholesale Electricity Prices and the Opportunity Cost of Water .....	76
BOX 5.1	Summary of 1989 Electricity Task Force Recommendations.....	140
BOX 5.2	Summary of 1992 WEMS Conclusions.....	145
BOX 5.3	Key WEMDG Recommendations.....	146
BOX 5.4	June 2000 Report of the Electricity Industry Inquiry .....	159
BOX 7.1	Benefits and Means of Increased Demand-Side Participation.....	198
BOX 8.1	Ministry of Energy under the Electricity Act 1968 .....	211
BOX 8.2	Key Provisions and Principles of the SOE Act 1986 .....	213
BOX 8.3	Electricity Amendment Act 2001 – Key Elements .....	220
BOX 8.4	Transpower's Evolving Statements of Corporate Intent ... ..	227
BOX 9.1	NZEM: One Market or Many?.....	254
BOX 9.2	Some Approaches to Measuring Market Power .....	259



## ABBREVIATIONS

<b>A</b>	Ampere/amp, a measure of electrical flow
<b>AC</b>	Alternating current
<b>ARP</b>	Accounting rate or profit (superseded by ROI), a measure of a distribution company's return on its ODV asset base, to be compared with WACC
<b>CCGT</b>	Combined cycle gas turbine
<b>CFD</b>	Contract for differences
<b>Contact</b>	Contact Energy Limited
<b>CPI</b>	Consumer price index
<b>DC</b>	Direct current
<b>ECNZ</b>	Electricity Corporation of New Zealand Limited
<b>EECA</b>	Energy Efficiency and Conservation Authority
<b>ELB</b>	Electricity lines business
<b>ENA</b>	Electricity Networks Association
<b>EPB</b>	Electric power board (superseded by energy company in 1993)
<b>ESA</b>	Electricity supply authority, comprising EPBs and MEDs (superseded by energy company in 1993, and then ELB in 1999)
<b>ESANZ</b>	Electricity Supply Association of New Zealand (superseded by ENA)
<b>EU</b>	European Union
<b>EV</b>	Economic value
<b>FTR</b>	Financial transmission right
<b>Genesis</b>	Genesis Energy Limited
<b>Gentailer</b>	Vertically integrated generator and energy retailer
<b>GST</b>	Goods and services tax
<b>GW</b>	Gigawatt = 1,000 MW = 1,000,000 kW = 1,000,000,000 W
<b>GWh</b>	Gigawatt hour, a measure of energy, being power expended over time = 1,000 MWh

<b>HVDC</b>	High-voltage direct-current
<b>IEA</b>	International Energy Agency
<b>IPP</b>	Independent power producer
<b>Km</b>	Kilometre = 0.62 miles
<b>kW</b>	Kilowatt = 1,000 W
<b>kWh</b>	Kilowatt hour
<b>LNG</b>	Liquefied natural gas
<b>MARIA</b>	Metering and Reconciliation Information Agreement
<b>MACQS</b>	Multilateral Agreement on Common Quality Standards
<b>Meridian</b>	Meridian Energy Limited
<b>MED</b>	Historically, municipal electricity department (superseded by energy company in 1993), or latterly, Ministry of Economic Development
<b>MPWG</b>	Market Pricing Working Group
<b>MRP</b>	Mighty River Power Limited
<b>MSC</b>	Market Surveillance Committee (of the NZEM)
<b>MW</b>	Megawatt = 1,000 kW = 1,000,000 W
<b>MWh</b>	Megawatt hour = 1,000 kWh
<b>N-1 Security</b>	System redundancy, to cover possibility of shortfall
<b>NEM</b>	National Electricity Market (operating in eastern Australia from 1998)
<b>NETA</b>	New Electricity Trading Arrangements (implemented in England and Wales from 2001)
<b>NGC</b>	National Gas Corporation
<b>North Island</b>	North Island of New Zealand
<b>NZAS</b>	New Zealand Aluminium Smelters Limited, owned 79.36% by Comalco and 20.64% by Sumitomo Chemical Company
<b>NZEM</b>	New Zealand Electricity Market (fully operational from 1 October 1996)
<b>OCGT</b>	Open-cycle gas turbine
<b>ODRC</b>	Optimised depreciated replacement cost
<b>OECD</b>	Organisation for Economic Cooperation and Development
<b>ODV</b>	Optimised deprival value = lesser of ODRC and EV, a measure of lines-company asset base for regulatory purposes



<b>PJM</b>	Electrical interconnection area encompassing Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia in the US, operating its energy market from 1997
<b>RMA</b>	Resource Management Act 1991
<b>ROI</b>	Return on investment
<b>SCI</b>	Statement of corporate intent, such as that required of SOEs
<b>SOE</b>	State-owned enterprise formed under the State Owned Enterprises Act 1986
<b>South Island</b>	South Island of New Zealand
<b>TCC</b>	Transmission congestion contract
<b>TFP</b>	Total factor productivity
<b>TPEB</b>	Trans Power Establishment Board
<b>Transpower</b>	Transpower New Zealand Limited
<b>TrustPower</b>	TrustPower Limited
<b>V</b>	Volt, a measure of electrical force
<b>W</b>	Watt, a measure of power
<b>WACC</b>	Weighted-average cost of capital
<b>WEMDG</b>	Wholesale Electricity Market Development Group
<b>WEMS</b>	Wholesale Electricity Market Study

All monetary figures are in New Zealand dollars, with 30 June 2005 exchange rates of:  
1 NZD = 0.92 AUD = 0.58 EUR = 0.39 STG = 0.70 USD = 77 YEN



# NEW ZEALAND: SELECTED ENERGY SOURCES AND USERS





REFORM TIMELINE

YEAR	REFORM STEP OR MAJOR EVENT
1984	<ul style="list-style-type: none"> <li>← Labour government elected.</li> <li>← <i>Review of the Role and Structure of the Electricity Division</i>, Electricity Division, Ministry of Energy, Phases I and II, July and November.</li> </ul>
1985	<ul style="list-style-type: none"> <li>← <i>Review of Electricity Planning and Electricity Generation Costs</i>, The Treasury.</li> </ul>
1986	<ul style="list-style-type: none"> <li>← Government's effective monopoly on generation removed.</li> <li>← State Owned Enterprises (SOE) Act 1986 passed.</li> <li>← Commerce Act 1986 passed, establishing general "light-handed" regulatory regime.</li> </ul>
1987	<ul style="list-style-type: none"> <li>← <i>The Task Force Report on Electricity Corporation Organisation Structure</i>, ECNZ Establishment Board, February.</li> <li>← Electricity Corporation of New Zealand (ECNZ) established as SOE on 1 April.</li> <li>← Electricity Supply Authorities (ESAs) become subject to income tax on 1 April.</li> </ul>
1988	<ul style="list-style-type: none"> <li>← Government establishes task force to review structure and regulatory environment for bulk electricity supply (and later entire industry).</li> <li>← Transpower (grid-owner/operator) set up as wholly owned subsidiary of ECNZ.</li> </ul>
1989	<ul style="list-style-type: none"> <li>← <i>Structure, Regulation and Ownership of the Electricity Industry</i>, Electricity Task Force, September, recommending (<i>inter alia</i>) separation of transmission and generation, privatisation (but no break-up) of generation, and corporatisation and privatisation of ESAs.</li> </ul>
1990	<ul style="list-style-type: none"> <li>← Ministry of Energy abolished.</li> <li>← Corporatisation of ESAs announced.</li> <li>← Trans Power Establishment Board (TPEB) established to oversee separation of grid from ECNZ.</li> <li>← National government elected.</li> </ul>

YEAR	REFORM STEP OR MAJOR EVENT
1991	<ul style="list-style-type: none"> <li>← <i>The Separation of Trans Power</i>, TPEB, September.</li> <li>← Government show-down with ECNZ over announced price increases.</li> <li>← <i>Electricity Pricing in New Zealand</i>, ECNZ submission to select committee inquiry on electricity prices.</li> <li>← Establishment of Wholesale Electricity Market Study group (WEMS).</li> </ul>
1992	<ul style="list-style-type: none"> <li>← Electricity Act 1992 and Energy Companies Act 1992 passed.</li> <li>← WEMS Reports 1–5, June–October, recommending creation of “facilitated” wholesale electricity market under centralised industry governance.</li> <li>← Winter power “crisis”.</li> <li>← <i>The Electricity Shortage 1992</i>, Report of the Electricity Shortage Review Committee.</li> </ul>
1993	<ul style="list-style-type: none"> <li>← Wholesale Electricity Market Development Group (WEMDG) formed.</li> <li>← Electricity Act 1992 comes into force on 1 April, with first stage removal of franchise areas and supply obligations for small customers (less than 0.5 GWh/year).</li> <li>← Energy Companies Act 1992 comes into force on 1 April, with ESAs established as energy companies and required to operate as successful businesses.</li> <li>← Transmission and wholesale energy prices unbundled.</li> <li>← ECNZ and ESA industry association (ESANZ) form EMCO to develop, implement and operate a wholesale electricity market.</li> </ul>
1994	<ul style="list-style-type: none"> <li>← New Zealand Electricity Market (NZEM) commences operation as secondary market for ECNZ hedge contracts.</li> <li>← Industry agrees Metering and Reconciliation Information Agreement (MARIA).</li> <li>← Legal separation of ECNZ and grid company Transpower (both government-owned SOEs).</li> <li>← Final removal of ESA franchise areas and supply obligations on 1 April.</li> <li>← Electricity (Information Disclosure) Regulations 1994 come into force.</li> </ul>

YEAR	REFORM STEP OR MAJOR EVENT
1994	<ul style="list-style-type: none"> <li>← <i>New Zealand Wholesale Electricity Market: Final Report</i>, WEMDG, recommending (<i>inter alia</i>) creation of wholesale electricity market and constraints on ECNZ dominance of generation.</li> </ul>
1995	<ul style="list-style-type: none"> <li>← June reform package, including formation of Contact Energy as an SOE by spinning off certain ECNZ generation assets, and industry (versus government) management of “dry year” risk via contracts between generators and wholesale buyers.</li> <li>← ECNZ issued directions by government under SOE Act limiting its new generation investments, requiring sale of new gas project and eight small hydro stations, and restricting vertical integration between generation and energy retailing.</li> </ul>
1996	<ul style="list-style-type: none"> <li>← Contact Energy formed as competitor to ECNZ.</li> <li>← ECNZ relieved of obligation to supply.</li> <li>← Government confirms reliance on competition to achieve efficiencies and consumer benefits in electricity, gas and telecommunications services.</li> <li>← Wholesale electricity market begins full trading on 1 October.</li> <li>← Electricity consumers have choice of supplier.</li> </ul>
1997	<ul style="list-style-type: none"> <li>← Government revises objectives for Transpower, requiring it to earn commercial return but now subject to efficiency goal.</li> </ul>
1998	<ul style="list-style-type: none"> <li>← <i>Better Deal for Electricity Consumers</i> announced by government, including final separation of ECNZ into three new SOE generators, pressure on industry to develop mechanisms to facilitate customer transfers, and separation of lines businesses from competitive activities.</li> <li>← Blackout in Auckland CBD.</li> <li>← Electricity Industry Reform Act 1998 passed.</li> <li>← Government asks EMCO to include policy statement regarding electricity supply in NZEM rules.</li> </ul>
1999	<ul style="list-style-type: none"> <li>← 40% of Contact Energy sold to Mission Energy (March) and balance privatised by public share float (May).</li> <li>← ECNZ finally separated, with formation of Genesis, Meridian and Mighty River Power, on 1 April.</li> </ul>

YEAR	REFORM STEP OR MAJOR EVENT
1999 CONT'D	<ul style="list-style-type: none"> <li>← Deemed profiling introduced to facilitate customer switching.</li> <li>← Restrictions lifted on generator vertical integration with retailing, and separation of lines from other activities effective from 1 April. Rapid formation of vertically integrated “gentailers” results.</li> <li>← Industry introduces self-governance arrangements for grid security, taking over responsibility from Transpower – Multilateral Agreement on Common Quality Standards (MACQS).</li> <li>← Labour/Alliance coalition government formed.</li> </ul>
2000	<ul style="list-style-type: none"> <li>← <i>Inquiry into the Electricity Industry</i>, June, recommending (<i>inter alia</i>) centralisation of industry governance and imposition of CPI-X price controls on distribution and transmission.</li> <li>← <i>Power Package</i> announced by government in response to the Inquiry.</li> <li>← Government announces Energy Policy Framework and releases government policy statement.</li> <li>← Electricity Governance Establishment Committee formed to merge NZEM, MARIA and MACQS per Inquiry recommendation, under threat of imposed merger should industry fail to agree.</li> </ul>
2001	<ul style="list-style-type: none"> <li>← Electricity Amendment Act 2001.</li> <li>← Electricity Industry Reform Amendment Act 2001 passed.</li> <li>← Commerce Amendment Act 2001 passed.</li> <li>← Commerce Amendment Act (No. 2) 2001 passed.</li> <li>← Winter power “crisis”.</li> </ul>
2002	<ul style="list-style-type: none"> <li>← Labour/Progressive coalition government formed.</li> </ul>
2003	<ul style="list-style-type: none"> <li>← Electricity Governance Establishment Committee referendum fails to win support for proposed self-governance arrangements, May.</li> <li>← Winter power “scare”.</li> <li>← Electricity Commission established to centralise industry governance and regulation (with Commerce Commission to implement price controls), September.</li> <li>← Electricity and Gas Industries Bill introduced, making widespread changes to earlier reforms, October.</li> </ul>



YEAR	REFORM STEP OR MAJOR EVENT
2003	<ul style="list-style-type: none"> <li>← Announcement of reserve generation measures to be taken by Electricity Commission (intended to reduce dry-year risk).</li> <li>← Commerce Commission announces thresholds for CPI-X price controls for electricity lines businesses and Transpower.</li> <li>← Electricity Governance Rules and Regulations set, December.</li> </ul>
2004	<ul style="list-style-type: none"> <li>← Electricity Commission assumes responsibility for electricity industry governance, including MARIA and NZEM, 1 March.</li> <li>← Electricity Governance Rules (for transmission pricing and investment) approved, April.</li> <li>← Whirinaki “dry year” reserve generation commissioned, June.</li> <li>← Government provides one-off partial underwrite of gas risks to SOE Genesis to facilitate “e3p” generation at Huntly, August.</li> <li>← Electricity and Gas Industries Act passed, October.</li> <li>← Transpower identifies priority grid upgrades as being into Auckland and Christchurch, and over the HVDC link, October.</li> <li>← Transpower commences consultation on routes for proposed 400 kV grid upgrade from Whakamaru to Otahuhu, October.</li> <li>← New Government Policy Statement on Electricity Governance released, October.</li> <li>← Low fixed-tariff option for small customers imposed, October.</li> <li>← Independent analysis released suggesting government may be willing to accept lower expected rate of return on SOE generation investments than would private investors.</li> <li>← Electricity Commission finalises guidelines for Transpower’s transmission pricing methodology, December.</li> </ul>
2005	<ul style="list-style-type: none"> <li>← Grid Investment Test approved under Part F of the Electricity Governance Rules, February.</li> <li>← Electricity Commission empowered to recover costs of overseeing supply security and electricity efficiency, March.</li> <li>← Government intervenes in grid-upgrade process, deferring Electricity Commission’s September 2005 decision deadline to mid-2006 (which falls after the 2005 general election), April.</li> </ul>

YEAR	REFORM STEP OR MAJOR EVENT
2005 CONT'D	<ul style="list-style-type: none"> <li data-bbox="265 287 1138 385">← Electricity Commission releases papers on options for enabling transmission alternatives, and seeks submissions on alternatives to Transpower's proposed 400 kV Waikato upgrade, May.</li> <li data-bbox="265 404 1138 469">← Transpower submits proposed transmission pricing methodology to Electricity Commission, May.</li> <li data-bbox="265 487 1138 553">← Commerce Commission begins investigation of whether the five main gentailers have too much market power, May.</li> <li data-bbox="265 571 1138 637">← Electricity Commission finalises Statement of Opportunities, with Grid Reliability Standard and Grid Planning Assumptions, May.</li> <li data-bbox="265 655 1138 720">← Vector takes over gas company NGC, and lists on sharemarket with Auckland Electricity Consumer Trust owning 75.1%, August.</li> <li data-bbox="265 738 1138 804">← Grid Upgrade Plan submitted to Electricity Commission by Transpower, September.</li> <li data-bbox="265 822 1138 888">← Mighty River Power conversion of mothballed Marsden B power station (to run on coal) approved, September.</li> <li data-bbox="265 906 1138 971">← Commerce Commission announces intention to impose price controls on lines company Unison Networks, September.</li> <li data-bbox="265 990 1138 1088">← Waitaki Catchment Water Allocation Board releases water allocation plan for Waitaki catchment, administratively weighing interests of hydro generators and other users, October.</li> <li data-bbox="265 1106 1138 1124">← New Labour-led coalition government formed, October.</li> </ul>

*In this chapter we describe the main actors in any electricity system, noting where New Zealand's arrangements involve differences, at even this fundamental level, from systems overseas. Having established the cast we then describe the relationships between these actors in power terms, taking power to mean more than just physics, although acknowledging that the physics of electricity supply significantly affects these power relationships. This construction sets up a theme that recurs throughout this book, namely that electricity restructuring fundamentally affects the political economy of electricity supply, not just its economics.*

*Such a construction highlights questions of market power, governance and regulation, in both static and dynamic terms. In turn these questions turn on notions of industry centralisation and decentralisation, or, in other words, the degree to which the industry's course is centrally or competitively determined. They are also affected by the industry's experience, with the balance of decision-making power being contingent on how well the industry handles, or is perceived to handle, challenges such as winter hydro shortages. How these questions are resolved fundamentally affects the incentives of private-industry participants to make the large, long-lived and irreversible investments that reformed electricity systems rely on to sustain security of supply and the level of competition required to make the reforms work. Such themes are previewed at the end of the chapter, where we look ahead to the rest of the book.*

## INTRODUCTION

### *The Importance of Electricity*

In New Zealand, as in other developed economies, we are all at least partially captive to electricity. While alternative fuels are available for some purposes, modern lifestyle, commerce, and industrial processes (not to mention our reliance on telecommunications) dictate that we rely on reliable, high-quality electricity supply for conveniences and services that we either cannot, or will not, do without. This is not to bow to the argument, often cited, that the provision of electricity is an “essential service”, or that electricity is an “essential good”. Such arguments overlook the fact that food, for example, is an essential good; yet no sensible suggestion is made these days for state ownership of all farms or supermarkets. To the extent that electricity is special, this is not why.

### *Historical Supply Approaches*

Given the current state of technology, the importance of electricity inevitably implies a reliance on typically large organisations that generate, transmit, distribute, and retail electricity from its source to where it is demanded. Historically these large organisations have not been subject to the forces of competition, or have characteristics that make

such competition either impossible or unlikely. As such, concerns about monopolistic behaviour in the electricity sector have either been seen as an obstacle to change or been resolved by parking the relevant concerns in state or local government ownership. Through such ownership it has been possible to impose obligations for security of supply, but where this was successful (and the results have been mixed) it has come at the cost of over-investment in capacity at consumers' or taxpayers' expense, and at times involuntary interruption to supply.

The experience with such arrangements, internationally, has not been altogether satisfactory. While in New Zealand electricity prices tended to remain at the lower end of the range when compared with other developed countries, this reflects the country's access to a relatively high share of hydro-electric power (rather than thermal generation) that has considerable sunk capital costs but low marginal operating costs, and does not tell us what that price should have been. It also reflects an historical subsidy from New Zealand taxpayers who funded the development of the country's state-owned electricity system even though for many years the state-determined price of electricity was less than that required to justify such investments on strictly commercial terms. As in other countries, political involvement in pricing and investment decisions and the growing awareness of inefficiencies in the sector eventually came to be regarded as obstacles to the nation's economic and social progress.

### *Winds of Change*

In the 1980s New Zealand, like Great Britain, embarked on a radical programme of economic reform.<sup>1</sup> Driven by political opposites – a Labour government in New Zealand and Margaret Thatcher's Conservatives in Britain – the two countries, like many later, shared similarities in their reform agendas. Fuelled by a need to reduce the government budget deficit, a desire to see state-owned business activities set on a more commercial footing, and the use of market-based mechanisms rather than politically driven state planning, the electricity sector found itself among those facing transformation. Aspects of the sector that had formerly been considered to involve intractable problems of monopoly found themselves subjected to new understandings about competition and the abuse of market power. Improvements in technology not only changed the means of electricity production and delivery, but also enabled new means to organise, monitor and coordinate the operations of the industry. It is from these origins that the current New Zealand electricity system emerged.

### *Purpose of this Book*

This book presents an appraisal of current institutional arrangements in the New Zealand electricity sector against the backdrop of its contemporary reforms. By contemporary it is intended to mean the current reforms that had their genesis in a radical shake-up of the New Zealand economy after a market-minded Labour government took office in

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<sup>1</sup> See Evans *et al.* (1996).

1984. This is to be contrasted with the various other reforms experienced in the sector since its inception in the 1880s, in the main involving increasing concentration of the ownership and control of key areas of the sector in central government. By taking a comparative approach it should be possible to discern which of those institutional or structural arrangements in New Zealand distinguish it from other electricity systems worldwide, and to assess therefore the extent to which general lessons can be drawn from the New Zealand experience (or from overseas experience for New Zealand).

While the contemporary reforms have sought to place greater reliance on market mechanisms to determine electricity pricing and influence future investments in the sector – displacing a measure of political influence over these matters in doing so – caution is required in describing these reforms as “deregulation”. The reality is that ongoing political interest in the electricity sector is inevitable, and so political input into the nature and evolution of the sector – regulation by name or effect – must be expected to play a continuing, albeit changing role. As such, this appraisal of the contemporary reforms should be thought of as an exercise in political economy and cannot be purely based in economics, as this would leave a fundamental driver of the reforms as externally determined and unexplained.

#### *Analytical Criteria*

An appraisal based in political economy requires various analytical criteria. These include the usual concepts of economic efficiency, both static and dynamic, referring to whether reform of New Zealand’s electricity sector has improved the nation’s “welfare” (respectively, contemporaneously and over time) – allocating resources in the best way and to where they are best used. Equity considerations are unavoidable, as who benefits from the reforms is a key driver of any further reform, given the political interest in the sector, and an obvious yardstick against which they can be measured. To some these are the only relevant considerations. Attention is also paid to how the reforms have affected the power of the various agents in the sector to make decisions that best affect themselves, touching on questions of governance as well as ownership and regulation, all of which can be expected to influence the likely evolution of the industry.

## LEAD ACTORS IN A MODEL ELECTRICITY SYSTEM

The lead actors in any electricity system typically fall into five main classes. The first comprises electricity **consumers**, which can be further decomposed (generally by annual energy consumption) into sub-classes of consumers such as residential, commercial and industrial. These consumers, particularly at the residential level, buy their energy from electricity **retailers**, which may be stand-alone enterprises or incorporated in other parts of the supply chain, and which might engage in other activities such as energy trading or hedging. In purchasing electricity, consumers typically must connect to electricity generators via power lines and associated equipment owned and operated

by **distribution** companies. In turn distribution companies typically connect to a long-distance **transmission** grid, comprising high-voltage power lines and associated equipment to which the source of electrical energy – the **generators** – ultimately connect. Variations on these themes are possible, for example, with industrial consumers connecting directly to the grid, or distributors having generation capacity of their own, but as a model it captures much of the electricity sector’s character.

In sharing much of this model New Zealand can be compared with other developed countries, although the makeup of the system has some distinguishing features. First is a relatively high dependence on hydro-electric rather than thermal generation, which offers the advantage of renewable energy but suffers from variable river inflows and low storage capacity. Second is the nature of the grid – being long, skinny and sparse and generally wheeling power from generation concentrated in the south of the country to demand concentrated in the north. Third is winter-peaking demand rather than summer, reflecting demand for heating rather than air-conditioning, as is more often the case elsewhere and complicating electricity provision because hydro-lake inflows are relatively low in the winter. Fourth is a relatively high electricity intensity (i.e. the share of electricity consumption as a ratio of national output), in part reflecting the fact that one industrial user – the NZAS aluminium smelter located at Tiwai Point in Southland – alone accounts for around 15% of annual electricity consumption. Finally, the New Zealand electricity system is geographically isolated, with no capacity to import power from other countries in times of need, or to export it for gain.

## “POWER” IN THE ELECTRICITY SECTOR

### *More than just Physics*

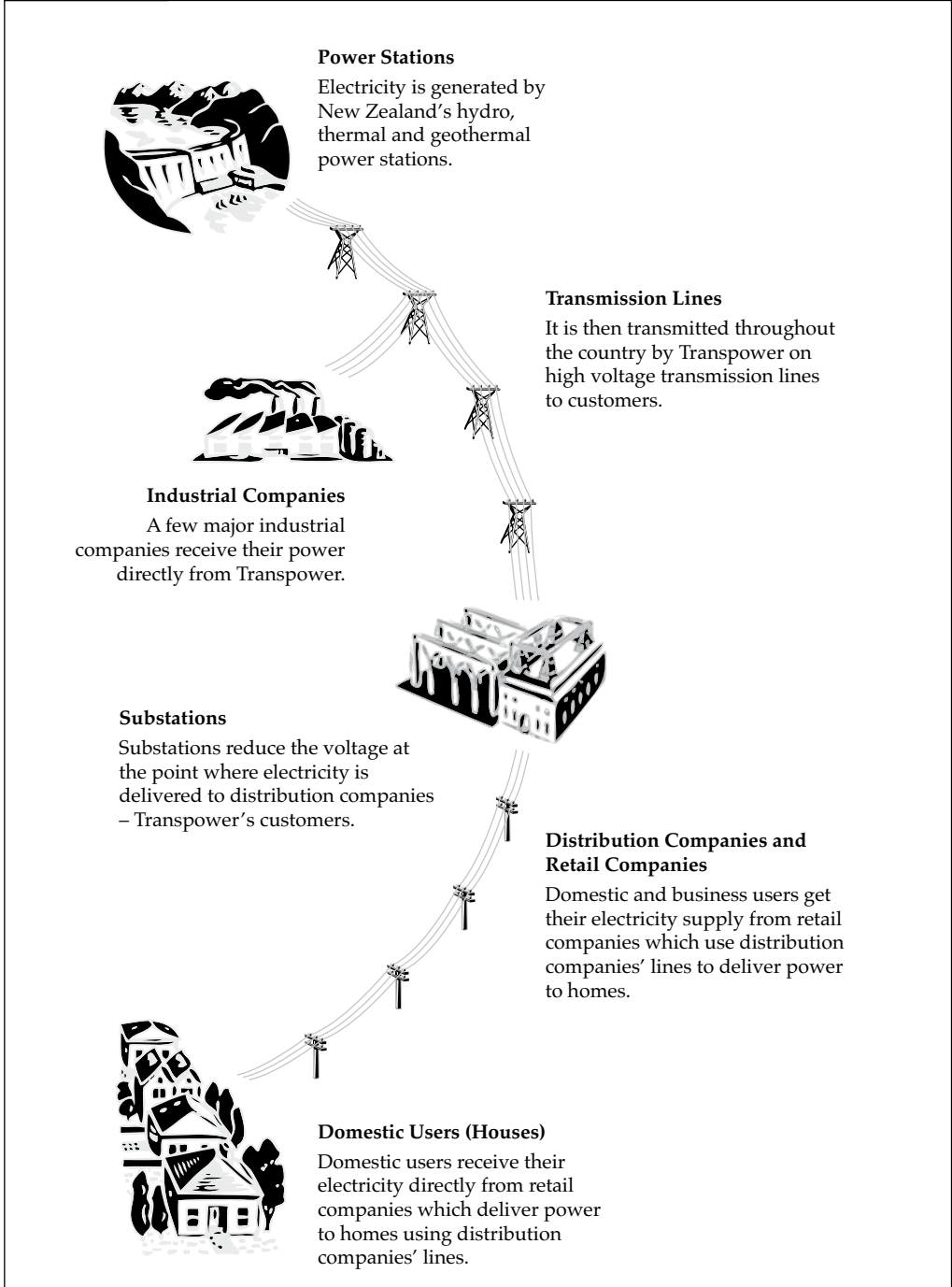
To say that electricity is about power is both tautology and insight. Any consideration of the electricity sector naturally demands that attention be paid to the physics of electricity and issues that, if not unique, remain points of distinction between it and other industries. Chapter 2 explores these points in some detail, but for now it is sufficient to note that electricity cannot be stored, its flows cannot be easily directed, and the actions of any one member of an electricity system can have consequences for all others. In economic terms electricity supply involves “externalities”, problems of “commons”, “public good” attributes, and in general an inability to match physical flows with contracts for both supply and usage. These issues pose challenges for replacing administrative approaches to electricity supply with more market-oriented forces.

### *Role of Technology*

Technological innovations, however, have led to changes in both the physics and economics of electricity. As well as the usual improvements in efficiency and information technology that we take for granted in any industry, the electricity industry is enjoying the development of new technologies that affect its makeup. Greater efficiencies

FIGURE 1.1

### Main Electricity Sector Actors in New Zealand



Source: Transpower (2003).

in thermal generation, such as combined cycle gas turbines (CCGT), affect the cost structure and hence output price of new generation capacity as it is developed to meet an ever-increasing demand. Advances in information technology allow the coordination of separately owned generators and transmission, and give rise to the potential for electricity users to monitor and change their consumption in response to short-term changes in electricity price. Similar advances mean it is also now possible to coordinate countless bids and offers for the real-time provision and demand for electricity so as to determine what price simultaneously satisfies all sellers and buyers, giving us a “spot” market price for electricity – a possibility that a few years ago could only be dreamt of. Greater use of DC (instead of AC) interconnections and networks, and advances in switching technologies, allow increasing control of actual power flows, better aligning physical and contractual flows. Finally, advances in technologies such as co-generation and wind-powered electric turbines are making feasible smaller-scale generation investments, and assist with a move towards distributed generation that locates supply closer to its demand and thereby mitigates the costs and monopoly issues associated with long-distance electricity transmission and distribution.

#### *Some Other Types of Power*

All of these technological innovations – affecting the physics of power in the electricity system – also give rise to the potential for changes to the other types of “power” in the system. In this context power can refer to market or monopoly power in generation, transmission or distribution – in other words the power of industry participants (including politicians) to manipulate prices, quantities or qualities to their advantage and potentially to the detriment of overall social welfare, both now and over time. Allied to this notion of power is the ability of consumers to decide which supplier they wish to purchase electricity from, or to change their consumption patterns in response to price changes (whether in terms of short-term usage decisions, selling surplus power via power exchanges, or longer-term decisions such as choice of appliances or energy efficiency measures). A third notion of power is to do with who controls the evolution of the industry, affecting the risks and incentives of all those contemplating investment in the sector.

#### *Importance of the Ability to Set Electricity Prices*

Central to these notions of power is the wholesale electricity market, an important element of which is the spot market. As in most countries, it is only very recently that New Zealand has enjoyed a stand-alone spot market that determines the price of electricity at any point in time. Being able to determine the price of electricity is clearly a key power to be enjoyed in any modern economy. If the price is too high, consumers are paying more than they should for their energy with a corresponding depression of economic activity that is reliant on electrical energy, and there is an incentive to over-invest in new capacity. If the price is set too low, then those who have funded investments in the electricity system in effect subsidise those who use electricity. This leads to over-consumption, underinvestment in new capacity, and artificial stimulation of sectors that rely on it.



It is therefore not surprising that for most of the history of New Zealand's electricity system political involvement in electricity pricing has played a prominent role. When governments control electricity generation and transmission – and hence the wholesale price of electricity – they have at their disposal a powerful policy instrument with which to stimulate or retard economic development, affecting industries, regions and, from their perspective most importantly, voters.

All of us are to some extent reliant on electricity, and electricity bills are a significant and ever-present reminder of this fact. Not all of us have access to alternative energy sources such as gas and, even when we do, the capital cost of installing alternative or dual-fuel use equipment can be prohibitive, and in any event it will not eliminate the need for electricity. You can't run your television on gas. If generation technology were so cheap and efficient that we could each use solar panels or our own gas, wind or co-generation turbine whenever electricity prices spiked then our reliance on large generators, a national grid and local distribution companies would be reduced, but we are not there yet. Hence, for as long as voters, commerce and industry need electricity and have limited ability to influence the price at which it is delivered, politicians will be interested in the price of electricity.

Before a true wholesale market for electricity developed in New Zealand, electricity pricing was essentially a politically driven process that led to relatively low electricity prices, taxpayer subsidisation of electricity infrastructure, and periodic jumps in prices as corrections were required.<sup>2</sup> Investment in electricity capacity was driven by supply considerations at a centrally planned level, resulting in over-investment in capacity at the taxpayer's expense. Funding by taxation itself can cause economic inefficiencies, but in addition inefficiencies in electricity investment and pricing meant that even when prices paid by consumers (as opposed to their true costs) were low, they might have been lower still if industry players had better information, incentives and capacity to act (in which case security and quality of supply might also have been enhanced).

#### *Influence of Electricity Prices on Consumer Conservation and Efficiencies*

Consumers had little incentive to conserve electricity or invest in energy-efficient technologies because they were not required to bear the true costs of delivering that electricity. Indeed, to the extent that they were charged prices that did not cover the true cost of electricity, consumers were effectively encouraged to over-consume electricity and invest in energy-inefficient technologies. This position was buttressed by the development of the large Maui gas field that, because gas cannot be economically exported, precipitated (on an international basis) a low price for thermal energy.<sup>3</sup> In the first 10 years of this period, government sought to encourage investment in energy-

<sup>2</sup> In 1978, for example, the wholesale electricity price – known then as the bulk supply tariff – was increased by 40%. One such cause for corrections was the temptation for governments to freeze electricity prices as a means to influence national price inflation, a measure that could only be sustained for short periods.

<sup>3</sup> At least for the 1979-2002 period. For a history of the Maui gas contract see Willis (1998).

intensive industry, reflecting the take-or-pay nature of the Maui contract, while at the same time it continued with the development of additional hydro-generation capacity.

### *Shifting Power amongst State Sector Electricity Actors*

The 1980s' programme of economy-wide reform included the corporatisation of generation and transmission, resulting in devolution by degree of electricity price-setting power to state-owned commercial enterprises operating at arm's length from central government. While such moves resulted in significant efficiencies and for a time mitigated the political temptation to influence electricity pricing, it was not until 1996 with the advent of a wholesale electricity market that the power to set electricity prices was placed in the hands of electricity market participants, and even then with qualifications. In this sense the New Zealand electricity sector witnessed a dramatic shift in "power", although recent reforms have significantly reversed this shift.

### *Control of the Wholesale Electricity Market*

Debate about the efficacy of the wholesale electricity market has continued since its inception. Concerns persist that the price-setting process is dominated by a handful of generators who are argued to possess considerable ability to manipulate power prices, if only under certain circumstances such as when hydrological reserves are low and/or when transmission constraints arise. This is despite a radical reconfiguration of the generation sector away from the all-but-complete dominance by the single, former state-owned generation company. Related concerns have been expressed that the evolution of the wholesale electricity market – until recently governed by rules hitherto developed by industry – favours incumbent generators, now **gentailers** both producing and retailing electricity. In contrast with the former arrangements under which the state-owned generation and transmission companies were responsible for ongoing security of supply (however unsuccessful they were in achieving that goal), the lack of any industry players being responsible for such security under the reformed electricity system has given rise to calls for intervention, particularly in the light of two winter power "crises" precipitated by lack of reserves and growing demand.

### *Consumer Choice*

Gentailer dominance of the industry is also regarded by some as a key obstacle to electricity consumers attaining the "power" to better control when and how they use electricity, and from whom they buy it. Until the introduction of "deemed profiling", effectively forced by government in 1999 and allowing electricity suppliers to trade customers without needing to introduce new metering technology, and despite the lifting of "franchise area" supply monopolies in 1994 which limited competition for energy supply, domestic electricity consumers are argued by some to have had limited scope to change electricity supplier to secure their preferred energy pricing. Without greater consumer power or external intervention it has been argued that the industry has little incentive to help consumers to shop around for the best deal, know when best

to switch their appliances off so as to reduce their energy bill, or find ways to use power more efficiently.

### *Market Power in Transmission and Distribution*

Market power concerns are not confined to gentailers, however, with both the transmission and distribution sectors attracting considerable ongoing attention. While technological change and changes in understandings have seen a worldwide rethink of the assumed monopoly nature of electricity generation, transmission and distribution are typically relegated to the monopoly “too-hard basket”. Since it is not economic to replicate transmission grids or electricity distributors’ “poles and wires”, and bypass of these is considered weak, it is regarded as inevitable that grid users and electricity consumers will be captive to the operators of such facilities and therefore vulnerable to monopoly exploitation. The past response relied mainly on public ownership in conjunction with regulation of some degree to attenuate the consequences of any such monopolistic behaviour – such as central government ownership of transmission and information disclosures. A current political aversion to privatisation has resulted in key options for reform in these sectors being taken off the agenda. Instead, where such measures have proven or simply been perceived to be inadequate, the preference has been for heavier regulation such as the threat of, or actual, price control.

### *Industry Governance and Development*

The “power” to shape the evolution of the electricity sector in New Zealand is arguably the most significant, and one which until recently has hung in the balance. Despite domination of the sector by state-owned generators and transmission, and the importance of government policy in shaping the overall development of the sector, New Zealand has enjoyed a number of important initiatives that have been “market-led” and free of political interference or intervention. Most notable was the development of the wholesale electricity market as the product of initiatives taken by industry players rather than central government, giving rise to industry-determined governance arrangements shaping the development of wholesale market rules (and hence the all-important wholesale electricity price-setting mechanisms). It is this power that has recently been sequestered by central government, in moves that appear to represent a radical departure from the broad thrust of previous reform in the sector, and current reform in other countries. Indeed, it is more generally a reversion towards those pre-dating the state-sector restructuring of the 1980s.

Combined with recent government moves to take a firmer hold over transmission pricing and investment, these other moves by government to take control of the evolution of the electricity sector will have important ramifications for the incentives and ability of other parties to plan and implement required investments in the sector. While such intervention can be argued to resolve real ongoing issues in the sector, such as frustration at the pace at which competition has developed at the consumer level, and consumers’ vulnerability to deliberate or unnecessary exploitation by distribution

companies, these moves are not without costs. A question now faced is whether they subtly but significantly affect the risks and incentives of industry players to respond to the needs of the industry. If they do so badly, it is possible that the import of the reforms will be lost and the New Zealand electricity sector will revert to a distorted reflection of its pre-reform self.

## A LOOK AHEAD

The chapters that follow present discussions on a smorgasbord of issues relevant to the contemporary reforms of the New Zealand electricity sector, with three scene-setting chapters leading the presentation. Chapter 2 deals with the technicalities of electricity markets, both in terms of the complicating physics and the abstractions involved in marrying the physics of electricity with the economics of markets. Chapter 3 provides a snapshot of the New Zealand electricity system, describing each of its major components. In Chapter 4, New Zealand's electricity reforms are outlined, against the backdrop of reforms in other states and countries. Chapter 5 gives a brief overview of New Zealand's electrical reform history.

Attention then turns to the selected contemporary "hot topics". As a form of "event study" the electricity-sector responses to successive winter power crises are examined in Chapter 6, with particular attention to the contrasting roles of involuntary demand curtailment and surging wholesale electricity prices in resolving the crises. Viewed against history, the fact of these crises does not fault the reforms, since similar episodes occurred pre-reform, and the reformed industry's response to these crises illustrates the efficacy of the reforms. In a related vein, the issue of encouraging a greater demand-side response to changing electricity prices is then discussed in Chapter 7. In reforming sectors worldwide this is regarded as one of the "holy grails" of reform, offering many potential benefits – if it can be achieved. These benefits include reduced market power, decreased capacity requirements, and greater security of supply. The problem is that there are good reasons why the horse might not want to drink, having been led to the water. Many consumers prefer not to vary their electricity demand in response to changing supply conditions, and are prepared to pay a price – an "insurance premium" – to not have to think about their supply. Future innovations are discussed that may offer consumers the encouragement they need to alter these preferences.

The next three chapters can be regarded as three different angles on the same question. How can welfare-enhancing competition be encouraged and sustained in a reformed electricity sector over time? Chapter 8 addresses the role of industry governance, and the relative merits of centralised and decentralised decision-making. For much of the past 20 years New Zealand has tended to charge industry participants with determining optimal industry evolution within the context of broad policy goals and light-handed regulation. More recently it has reverted towards the more centralised, administrative model in place before the reforms. This change in direction is predicted to enjoy little

success in terms of its stated objectives, and seriously undermines the effectiveness of otherwise useful decentralised initiatives.

Chapter 9 turns to defining and addressing the “evils” of market power and gaming observed in reformed electricity systems worldwide. Market power of some degree is argued to be inevitable in any electricity system, be it state-owned monopoly or privatised oligopoly, as is the issue of strategic behaviour by market participants. The ideal of “perfect competition” is not even close to attainable and is not therefore the relevant counterfactual, and so market power is not an automatic indicator of reform failure. Regulatory responses to these issues are considered in this light, with the costs of regulation emphasised as well as their benefits, and alternative approaches suggested. New Zealand’s recent shift from light-handed to heavy regulation is critically appraised.

Finally, encouraging investment in a reformed environment is discussed in Chapter 10. For generation, the goal of ensuring that capacity is able to meet ongoing demand is cast in a light more appropriate to reformed sectors. For example, the value placed on supply security by consumers is identified as an important driver of investment, which is to be contrasted with universal supply obligations of old. The difficulties in encouraging transmission investment are then noted, including the problem of investment impasses when generation and the grid are separately owned, given substitutability and complementarities between generation and transmission (and demand-side responsiveness). The centrality of grid investment to the evolving competitive topology of the sector and facilitating investment is identified. Possible solutions are proposed and weighed, including the use of customer or regulated private ownership, with the pitfalls of poor decisions emphasised. Current policy settings are likely to impede private investment in the New Zealand electricity sector, reinforcing the reversion towards centralised control and state ownership.

In many ways New Zealand’s reforms have been in the mainstream of those internationally; in others, and more recently, divergences are emerging. By the conclusion of this book in Chapter 11, the reader should have a sense of not only the nature and course of New Zealand’s reforms in time and space, but also of the efficacy of New Zealand’s solutions to issues that confront those debating reform in electricity systems worldwide.



*In this chapter we set out the features of electricity supply meriting special attention. This is followed by some fundamentals of market design and operation, both in general and for electricity markets in particular. The final section assesses the arranged marriage of economics and engineering represented by the creation of markets for electricity.<sup>1</sup>*

## INTRODUCTION

The generation, transmission and distribution of electricity have characteristics that, uniquely and otherwise, give rise to special considerations relative to the supply of other goods or services. In the main these hinge on the ephemeral nature of electricity and complications associated with the physics of electrical flows through interconnected networks, and they create the challenge of designing economic arrangements to suitably package electricity for sale using models of market-based exchange more easily applied to more typical goods or services. A number of these complications are “buried” when electricity is produced and allocated under some form of central planning and administration, but they become obvious when attempting to introduce forces of market competition into its creation and supply among voluntary, private-market participants.

## WHAT IS SO SPECIAL ABOUT ELECTRICITY?

### *In General*

Any special attention that is paid to electricity is not because it is intrinsically “essential”. While most modern economies are in some part captive to electricity, this is because it is integral to our lifestyle and quality of life. Only in exceptional cases is electricity essential to life itself, so in this regard it must be distinguished from food, clean water and shelter. Also, components of the electricity sector traditionally thought of as “monopolies” are now regarded as being susceptible to the usual forces of competition, especially electricity generation and retailing but also (to lesser degrees) transmission and distribution. And certainly having “monopoly” characteristics is not itself that remarkable. So for electricity’s special or distinguishing features, if any, we must look elsewhere.

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<sup>1</sup> A reader wishing to do justice to this topic might consult a more comprehensive coverage such as that in Stoft (2002).

Unlike virtually any other commodity, electricity cannot be stored on a significant scale given current technology.<sup>2</sup> Its supply and demand is instantaneous, with electrons flowing at the speed of light from generation to load – its ongoing delivery requires its ongoing creation. In fact it is only at the instantaneous level that electricity can be regarded as having commodity-like characteristics (i.e. having some measure of physical homogeneity), but even then its quality can vary across location because of the qualities of the medium through which it flows (i.e. the wires and other hardware in electricity networks).

The physical nature of electricity is defined in terms of features such as voltage (i.e. force), current (i.e. flow) – together, power – and, as is typical for electricity networks working with alternating (AC) rather than direct currents (DC), frequency.<sup>3</sup> While any single generator might be rated to produce electricity of precise electrical characteristics, once that generator's output is conveyed to demand via electrical wires additional factors then affect those characteristics. In the simplest case the electrical resistance of those wires gives rise to electrical losses (i.e. energy is lost as resistance in the wires causes them to heat). Furthermore, the characteristics of the electricity supplied will depend on the use to which it is put, with both supply voltage and frequency affected by the characteristics of the appliances and other equipment being supplied.

More important, however, is the fact that when one or more generators are connected to one or more electricity users via an electricity network the electrical characteristics of the system are then dictated by the nature of the network as a whole. The supply or use of electricity by any one party can affect the characteristics of electricity flowing through other parts of that network and to all other users.<sup>4</sup> Furthermore it becomes impossible in commonly used AC networks to control flows from source to load, with

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<sup>2</sup> Super-conductor and battery technology may one day improve to the point where useful amounts of electricity might be stored, but not in the foreseeable future. If and when it does, the economics of electricity supply will be markedly affected.

<sup>3</sup> A direct current (DC) is one in which electrical flow is constant with time, all other things (e.g. voltage, circuit resistance) being equal. By contrast, an alternating current (AC) is one which oscillates over time. An advantage of alternating currents is that they can be stepped-up using transformers to very high voltages which can then be transmitted over power lines – which have electrical resistance – with lower losses from heating than can lower voltages. These high AC voltages can then be stepped-down to usable voltages closer to load. Direct currents are not so easily stepped up or down, but can involve less losses than equivalent AC power flows. This arises because long-distance AC transmission is affected by another electrical property, capacitance, giving rise to “reactive power” that does not oscillate in time with the main AC flow, resulting in wasted power flows. For this reason high-power long-distance electricity transmission can more efficiently be achieved using direct currents, with the additional hardware costs being balanced by lower losses. This explains why power is transmitted between New Zealand's two main islands over a high-voltage DC (HVDC) link. See, e.g., FAQs at [www.transpower.co.nz](http://www.transpower.co.nz).

<sup>4</sup> In networks with alternating currents both voltage and frequency “give” when too much energy is demanded from available generation. A loss in frequency can be especially telling for generators whose plant operates with large spinning components designed to operate best at a certain rate, resulting in increased wear and tear. Considerations such as these give rise for the need for common quality standards and operating parameters in electrical networks.



electrons flowing throughout the network following physical laws,<sup>5</sup> and all generators simultaneously supplying all consumers.<sup>6</sup> Unlike other types of networks such as gas or railroads (or even some configurations of telecommunications networks), electricity networks do not involve the physical delivery of a given product to/from specified production/delivery points.<sup>7</sup> In other words, with electricity there is a mismatch between physical and contractual flows. It is therefore impossible to say that one particular generator supplying a given amount of electrical power supplied any particular quantity of electricity consumed.

Furthermore, the physical limitations of electricity transmission and distribution networks are such that their ongoing operation requires active monitoring of how much power is flowing along any given path (in simplest terms a transmission line can be thought of as a highly rated and expensive piece of fuse-wire). Since electricity supplied and demanded in a network must balance at all time, should any particular network path be “constrained” or removed from service (either to avoid or because of a fault), this can markedly affect the characteristics of the remainder of the grid, and the make-up of available generation and feasible demand. For an extreme example, loss of one section of the transmission grid might mean a certain number of generators can no longer be connected to demand, implying that existing demand must be supplied by other existing or additional generators, or simply cannot be met. In the latter case this excess demand might have the capacity to cause additional transmission failure, or to so significantly alter the characteristics of remaining power flows that it must be shed by the grid operator if the integrity of the transmission system and the electricity it supplies are to be maintained.<sup>8</sup>

<sup>5</sup> For example, Kirchoff’s laws summarise the natural propensity for electricity to simultaneously flow along all paths in a network – but with flows along each network path in inverse proportion to its resistance.

<sup>6</sup> As noted in Van Doren and Taylor (2004), such networks represent a form of “commons”, the problems of which have long been familiar to economics and law. Chapters 9 and 10 discuss these issues further, as well as those of natural monopoly, “externalities”, and “public goods” often ascribed to electricity networks.

<sup>7</sup> As noted in Joskow (1997), an electricity grid is not just a transportation system but a complex coordination system directed at meeting a vector of electricity demands using geographically dispersed generators and subject to stringent operating requirements to maintain network-wide electrical characteristics. It is for this reason that vertically integrated electricity systems have commonly been the preferred form of ordering around the world for much of the past century, internalising as they do the coordination and investment problems associated with electricity networks. With improvements in information and communications technology and advances in understandings of market design, however, more decentralised solutions are possible, facilitating competition where previously there was often otherwise monopoly.

<sup>8</sup> It should be noted that such systemic contagion effects are not wholly unique to electricity systems. Central banks are commonly concerned to see the prudential management of banking and other financial systems because of the possibility of failure in one part of the system creating devastating ripples throughout the rest. While such financial crises can develop quite rapidly they will not take place nearly as rapidly as in electricity networks, and in financial systems it is possible to interrupt specific financial flows in corrective ways that cannot be replicated for electricity flows. To extend the analogy further, however, it can be noted that inter-bank settlements depend on the combined solvency of a bank system’s constituent banks, and that a central (or reserve) bank’s ability to influence a bank system’s liquidity to avoid any contagious insolvencies bears some resemblance to an electricity grid operator’s access to ancillary services (see later) to maintain an electricity network’s voltage and frequency.

An additional complication arises from volatility in electricity demand. While it is an involved exercise to coordinate multiple units of generation and transmission, and generator and grid reliability is such that available generation and grid capacity at the instant of supply can be forecast with some accuracy, the same cannot be said of electricity demand. Since physical flows of electricity to any one customer cannot be controlled by generators or lines operators (short of larger direct-connect customers being switched off or classes of customers having their supply limited), the actual amount of electricity demanded at any one instant is an unpredictable function of the combined instantaneous decisions of multiple electricity users.<sup>9</sup> It is for this reason that grid management is especially complicated, requiring the availability of either reserve generation or interruptible load available at short notice. A challenge in designing markets for electricity is to allow market participants to determine how best this should be achieved, as opposed to relegating such decisions to supply-focused “technicians” who cannot be expected to understand the differential effects of their system management decisions on multiple and heterogeneous electricity suppliers and users, let alone best know how to economically balance their varying and sometimes competing interests.

To make matters worse, most electricity users do not have access to timely and accurate information regarding how much electricity they are consuming and what their consumption will cost them. While larger consumers with considerable costs arising from their electricity usage have sufficient incentives (and, given current technologies, the means) to keep a close eye on cost efficiencies at the time of consumption, most users only discover this information long after the fact when they receive their monthly power bill, and even then often at fixed unit prices. As such, for most consumers electricity demand is typically loosely controlled and highly unresponsive to changes in electricity price, at least in the short term (if not longer).

These characteristics are common in electricity networks and are present no matter what the organisation of the electricity system.

#### *In New Zealand*

As discussed and illustrated in Chapter 3, electricity supply in New Zealand is subject to some additional distinguishing characteristics. By virtue of the country’s geography and population concentrations, much of its generation capacity is located in hydro catchments in the South Island while electricity demand is located more in the north of the North Island. The transmission grid that typically transfers power generated in the south to demand in the north is long, skinny and sparse, as opposed to the more balanced, multi-path networks observed in other systems. It is possible that New Zealand’s grid topology is less exposed to systemic failure than in more balanced grids

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<sup>9</sup> In New Zealand, for example, a sudden cold winter snap can lead to a correspondingly sudden increase in electricity demand as users turn on their electric heaters.

(e.g. with cascading failures such as that in the north-eastern US in August 2003), aided by the connection of the North and South Island grids via a direct current link.<sup>10</sup> As in any grid, however, New Zealand faces the potential for transmission constraints to complicate the coordination of the country's many points of electricity supply and demand, with physical isolation of various regions' electricity sub-systems from other parts of the electricity system occasionally arising.<sup>11</sup> The fact that New Zealand is geographically isolated from electricity systems in other countries and is therefore unable to export surplus electricity or import it in times of shortage only extends this complication to the national level.

Another distinguishing feature is New Zealand's reliance on a significantly higher share of hydro generation than in other countries (as opposed to coal, gas, nuclear or other forms of generation), and only limited hydro storage capacity. With electricity demand peaking in the cold winter months, this has the potential to cause supply shortages in years of low hydro inflows and/or high demands (such as those arising in especially cold winters).

There is also a "loss and constraint rental" associated with the supply of electricity under New Zealand's electricity market arrangements. In general, the supply curve for electricity will slope up as lower cost generation is supplanted by higher cost generation as more electricity is produced. In addition, the supply curve may rise when losses and congestion on the grid increase as throughput expands. New Zealand's wholesale market has "marginal-loss pricing" which means that electricity prices reflect the losses in transmission made on the last unit of electricity transmitted (a rental for scarce transmission capacity), further suggesting an increasing supply curve, particularly at any point in time.

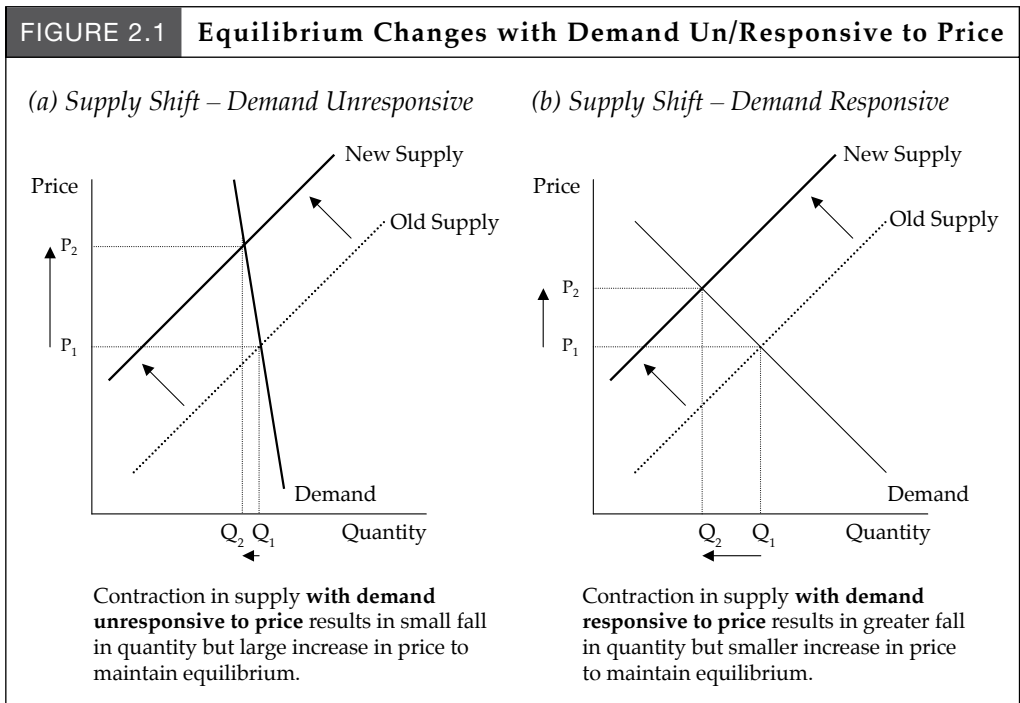
### *Price-Inelastic Electricity Demand*

Figure 2.1 illustrates a complication commonly associated with markets for electricity. Once again assuming that suppliers comprise multiple generators with varying supply costs, the supply curve can be represented as shown. Similarly it can be assumed that there will be some degree of negative association between electricity demand and electricity price, if only because some larger users have the technology to quickly change their consumption decisions in response to market price. Accordingly the demand curve for electricity should slope downwards to the right, as below, but it

<sup>10</sup> Chapter 10 discusses the suggested merits of smaller AC networks separated by DC linkages, as opposed to large AC networks, one of which is that such an approach reduces the risk of failure on one part of the network affecting all other parts. Such DC interconnections can help to localise network failures, allowing the adoption of more aggressive grid operating policies, thereby increasing effective available grid capacity.

<sup>11</sup> Indeed, loss of the critical high-voltage direct-current link between the North and South Islands can and has resulted in the physical separation of their related sub-systems (see Chapter 6). A consequence of such separations is a reduction in the number of generators vying to supply demand in each region, and/or the number of consumers seeking supply, with the potential for either to exercise some degree of "market power", in the economic sense, under such circumstances (see Chapter 9).

is commonly argued that the unresponsiveness of aggregate electricity demand to changes in electricity price suggests that the electricity demand curve's slope is very steep (economists say that this means the "price elasticity" of electricity demand is low). Assuming that a major generator suffers an unforeseen outage, and so only more expensive generation is available to supply demand at any price – i.e. that the supply curve for electricity shifts up – Figure 2.1(a) illustrates what happens to the equilibrium electricity price and quantity when demand is unresponsive to price changes.



Source: Richard Meade.

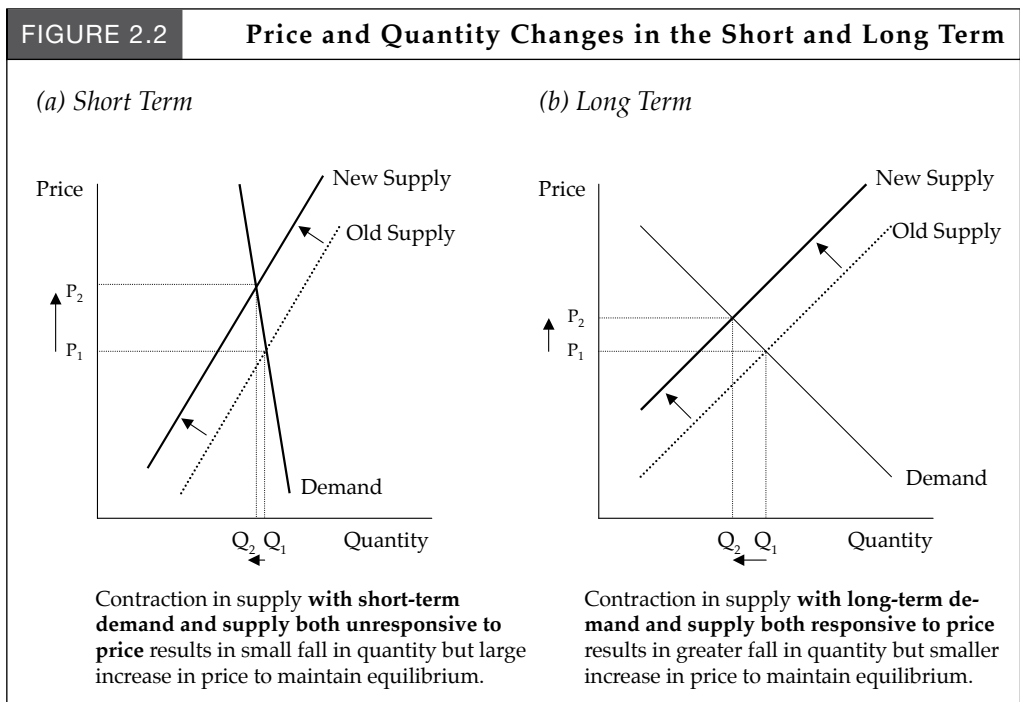
Figure 2.1(b) illustrates the corresponding changes if it can instead be assumed that demand is highly responsive to changes in electricity price (i.e. the demand curve is flatter). As should be apparent, for a given shift in supply the equilibrium electricity price is predicted to rise more sharply, and electricity consumed fall much less, when demand is less responsive to price changes. In fact, it is often argued that instantaneous electricity demand is essentially fixed, meaning that the demand curve for electricity can be represented by a vertical line at the quantity demanded, and that any change in supply conditions (i.e. shift in supply curve) feeds wholly through to price rises with the quantity demanded and supplied unchanged.<sup>12</sup> Analyses such as these are

<sup>12</sup> Over the longer term, electricity demand should be regarded as more price-responsive as consumers have greater ability to adopt energy-efficient technologies and multi- or alternative-fuel appliances.

often used to back calls for regulatory or other changes encouraging greater price-responsiveness in electricity demand, or “demand-side response” (see Chapter 7).

### *Short Run versus Long Run*

The distinction between short- and long-term supply and demand is illustrated in Figure 2.2. Just as electricity demand is often regarded as unresponsive to price in the short term, so too can the supply of various products. The supply of fresh foods, for example, is typically regarded as completely price-invariant in the short term, with harvested goods (e.g. fruit, vegetables, landed fish) being in fixed supply at the market place, and requiring immediate sale to avoid spoilage.<sup>13</sup> Short-term electricity supply is generally not so price-invariant, with generators typically having some capacity to increase output at short notice to meet increased demands, although this capacity might be limited because of limited fuel reserves. In the longer term, new generation can be built to meet growing demand, implying greater price-responsiveness (i.e. flatter electricity supply curve) than in the short term. Figure 2.2 illustrates how price changes in response to a change in short-term electricity supply (e.g. generator outage) should be expected to be greater than those arising to a longer-term supply change.



Source: Richard Meade.

<sup>13</sup> It is understandable that in such cases vendors simply try to achieve the highest price possible with available buyers, typically via some form of auction.

*Decreasing Price Elasticity of Electricity Supply*

A second complication often discussed in the context of electricity markets is the combination of demand being not responsive to price (i.e. “price-inelastic demand”) and sharply rising costs of additional generation, particularly for generation “at the margin” or, in other words, that which is likely to be the plant represented by the point at which supply intersects demand. The latter can arise where the supply curve is comprised of differing generation technologies with rising output costs. An example of this is when hydro generation with low unit-production costs is followed by coal- or gas-based generation with higher running costs.<sup>14</sup> In this case the supply curve is upward sloping at an increasing rate, and so when this is combined with price-inelastic demand it is predicted that electricity price changes will be greater with movements in either supply or demand curve than they would be with elastic demand and/or more slowly rising supply costs.

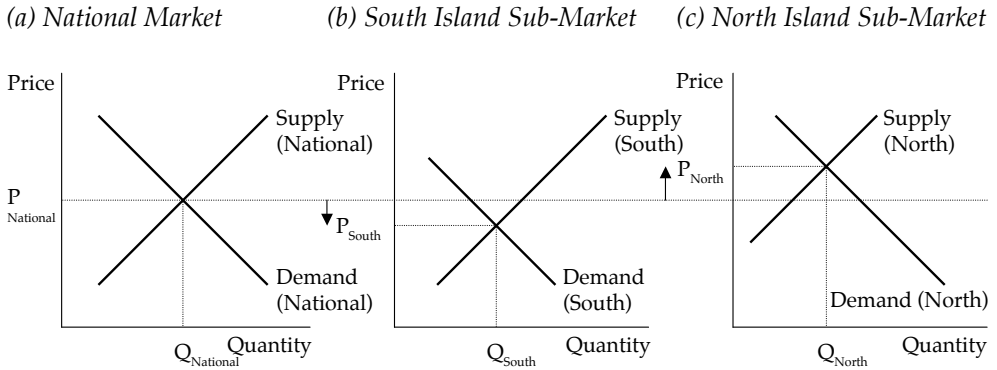
Finally, while market supply and demand curves are usually thought of as the aggregation of individual supply and demand curves (just sum quantities at each price), electricity markets can illustrate this principle in reverse. This can arise, for example, when transmission constraints cause the electricity market to “regionalise” or fractionate into geographically distinct sub-markets. Figure 2.3 illustrates this scenario, assuming a grid like that in New Zealand, with the North and South Island grids connected by a HVDC link across the Cook Strait between them. Figure 2.3(a) represents the national electricity market, whereas Figures 2.3(b) and (c) present the respective regional submarkets arising, for example, when the HVDC suffers an outage.<sup>15</sup> In the South Island the supply/demand balance favours supply – with significant generation relative to local demand – whereas in the North Island it favours demand. Accordingly, when the North and South Island electricity markets “separate” because of an outage in the inter-island HVDC link, a rise in the electricity price is predicted for the North Island relative to the national price, whereas the South Island price is predicted to fall (as it did during a major loss of the link in early January 2004, with Christchurch prices falling and Wellington/Auckland prices rising; this is discussed further in Chapter 6 and is illustrated below).

*Centralised Electricity Markets*

Centralised electricity “pools” are commonly, but by no means always, the preferred market arrangement adopted in countries reforming their electricity sectors. They rely on optimisation models to determine which generation units to dispatch at the least overall cost, taking into account technical constraints such as the need to maintain network

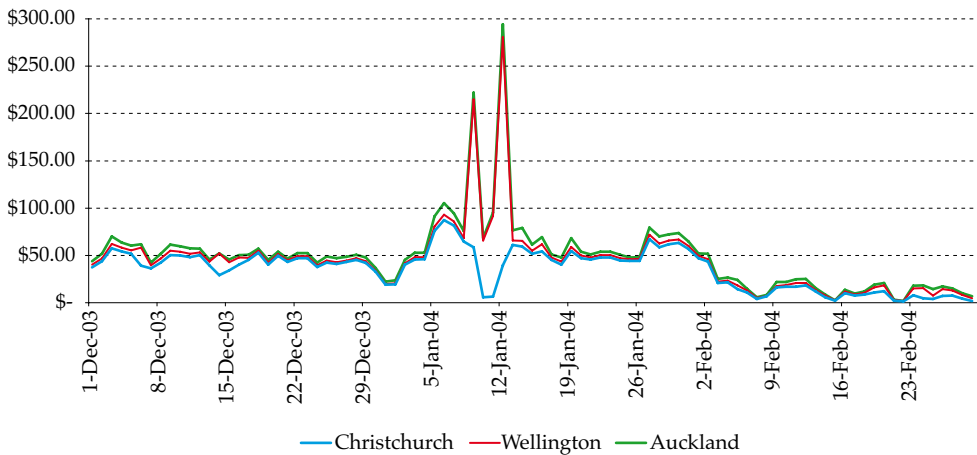
<sup>14</sup> The fuel (water) cost of hydro generation is typically low relative to other fuels; however, the capital cost may be much higher. Thus, once hydro generation is installed it is relatively cheap to run in all except dry years, but new hydro plants may be expensive relative to plants using other fuels.

<sup>15</sup> As it did for a number of days in early 2004, discussed further in Chapter 6.

**FIGURE 2.3 Price Separation Following Loss of Inter-Island HVDC Link**

When the national electricity market fragments owing to loss of the inter-island HVDC link, price is expected to fall for South Island electricity customers, for whom the supply/demand balance favours supply, and increase for North Island consumers for whom the reverse is true. Whereas the usual market aggregation technique would suggest that  $Q(N) = Q(Sth) + Q(Nth)$ , the loss in HVDC link would likely result in  $Q(N) > Q(Sth) + Q(Nth)$ , for example because of decreased generator competition and possible increases in transmission congestion elsewhere as alternative generation is redeployed to meet demand in each island.

*Actual HVDC Loss in January 2004 – Main Centre Spot Wholesale Prices (\$/MWh)*



Source: M-Co data; and Richard Meade for (a), (b) and (c).

security. An obvious rationale for a centralised electricity market over decentralised alternatives is that it provides a clear way to coordinate electricity system operations, recognising the inter-dependencies between generation and transmission. When making transitions from electricity systems dominated by an engineering perspective it is not surprising that the market models adopted retain – perhaps too much so – a

measure of centralised technical coordination. As one New Zealand writer put it: “The problem with the New Zealand electricity system is that 80% of production is hydro-electric, with only 12% of annual demand being storable. The problem of co-ordinating the reservoirs and inflows to avoid either shortage or excessive burn of thermal fuel must be recognised when creating competition”.<sup>16</sup> An economist, of course, would suggest that a properly functioning market would provide the necessary price signals precisely to optimise such considerations, but at the same time take into account the all-important but missing variable in the engineer’s equation, consumer preferences.

Such considerations aside, any reformed electricity system must involve some means to determine how generation is dispatched to meet demand at each point in time. The centralised approach does so explicitly, usually with some form of market-economics-mimicking model subject to technical constraints determining which generators meet expected demand at “least cost”. This, of course, is not to say that electricity pools do, or do not, dispatch the economically optimal generation, but harks back to an engineer’s mathematical programming model at the heart of central planning.<sup>17</sup> As it happens, the only features of electricity systems that need interfere with generation dispatch are those of technical feasibility (i.e. can dispatch take place within transmission operating constraints) and balancing (i.e. is extra generation, or load reduction, required to ensure instantaneous balance between supply and demand). Otherwise a decentralised market approach to determining which generators should meet demand is entirely feasible, and indeed occurs. Arguably it is also more likely to determine the economically optimal dispatch of generation to meet demand (see Appendix 2.2 for a case study on decentralised decision-making and the New Zealand electricity market).

### *Decentralised Electricity Markets*

Examples of decentralised electricity markets include the New Electricity Trading Arrangements (NETA) operating in England and Wales since 2001, and the “PJM” interconnection area encompassing Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia in the US. NETA represents the almost polar case where 98% of electricity is self-dispatched through generators and consumers entering into bilateral contracts for delivery up to years ahead, whereas in PJM around 64% of electricity traded is self-scheduled.<sup>18</sup> A number of EU member states’ electricity systems are based around such decentralised trading using power exchanges. By contrast around 20% of electricity traded in the New Zealand Electricity Market (NZEM) did so through bilateral trades, with the balance (80%) dispatched via a centralised pool. The National Electricity Market (NEM) in Australia is a compulsory pool through which all electricity is dispatched, representing the polar opposite to decentralised self-dispatch.

<sup>16</sup> Boshier and Gordon (1996).

<sup>17</sup> Contreras *et al.* (2004) show that decentralised optimisations by profit-seeking companies with imposed balancing requirements can in fact lead to optimal and technically feasible generation dispatch.

<sup>18</sup> Zhou *et al.* (2003).



### *Comparing Electricity Market Types*

Each approach has its advantages and disadvantages. Centralised pools allow the pooling of credit risks, which can be material when severe price rises cause market participants financial distress. They publish electricity prices that are transparent, and for electricity traded for short-term delivery – where electricity has the most uniform characteristics – provide economies of scale in transacting. Where pools coexist with bilateral trading, market participants have a means to compete away or “arbitrage” excessive spreads or pricing inefficiencies arising in either mode of transaction.<sup>19</sup> Pools suffer, however, from their rigid specification, which can create opportunities and incentives for “gaming” (see Chapter 9), and from their imposition of a stylised economic market model subject to technical constraints rather than simple reflection of an underlying market.

Decentralised electricity markets, by contrast, spurn the guiding hand of centralised dispatch in favour of providing means for parties to privately contract, with a centralised balancing market – covering just 2% of electricity traded in England and Wales, and 36% in PJM; and, even then, both NETA (like various other EU systems) and PJM allow market participants to transact for the necessary balancing. While decentralised bilateral trading need not involve the publication of transacted prices – which may in fact be the preference of some parties – the use of power exchanges to facilitate contract trading with published buy and sell prices (particularly since competing exchanges have been created) should be expected to yield economically efficient prices. Indeed, with advances in communications technology the problems of search, price formation and transacting (and indeed, grid balancing) are just as easily resolved via decentralised exchange as they are through pools. Under the decentralised approach credit-risk issues are borne more by individual traders than under a pool approach, but opportunities and incentives for market rules to be “gamed” are reduced, in some cases eliminated.<sup>20</sup>

It is possibly too early in the history of reformed electricity systems to determine which approach is superior. The shift from the centralised pool to decentralised NETA in England and Wales has been found to have had promising results in terms of price declines, although this has been attributed to other causes (see later). It has, however, resulted in a dramatic decline in reported abuse of market power and market rule gaming compared

<sup>19</sup> Fixed price contracts of varying terms can be implemented for electricity delivered to the pool, by means of hedge arrangements. One very common arrangement is a contract for differences (CFD) that one party enters into with another at a particular location (node of the grid). If  $p$  is the nodal price then the CFD for an amount of electricity  $q$  requires that the seller (S) is paid  $(p^* - p)q$  by the buyer (B). If the spot nodal price  $p$  exceeds (falls below) the strike price  $p^*$ , S pays B (receives from B) the amount  $(p^* - p)q$ . Hence if S receives the spot price on its sales, its revenue after settlement of the CFD is  $pq + (p^* - p)q = p^*q$ , and B's is  $-pq - (p^* - p)q = -p^*q$ . In effect, electricity is exchanged between S and B at the fixed strike price no matter what the spot price is for given quantity  $q$ . The CFD is a financial contract that virtually duplicates a fixed-price bilateral physical contract for electricity.

<sup>20</sup> Decentralisation may be sufficient but not necessary to mitigate gaming. Where centralised market rules are vulnerable to gaming, it may be possible to improve market rules so as to reduce this vulnerability.

with the previous market design.<sup>21</sup> A compelling lesson is that the decentralised approach – with only the barest of technical encumbrances – is indeed feasible.

## ELECTRICITY MARKETS – HOW THEY WORK

### *Engineering Meets Economics*

The need in AC electricity networks to preserve operating voltage and frequency in the face of instantaneous and unpredictable demand, while ensuring this does not breach critical operating constraints, requires continuous monitoring of grid-wide conditions and some means to procure supply/demand balance at all times. To the extent that market mechanisms are used to determine which generators meet demand at any point in time, those mechanisms must allow for all of these interdependent considerations. In the main these considerations boil down to mechanisms for coordination, and the extent to which centralisation is necessary to achieve this.

### *Electricity Market Architecture*

Typically the required coordination is achieved by implementing an electricity market architecture that draws together a combination of “planned” and market-based components. The major players in this regard, detailed below, usually include a system/grid operator, and a market operator. In some cases the two players are combined, and sometimes also with the grid owner. Aspects of each player’s roles might also be decomposed into finer roles, any or all of which might be undertaken either separately or combined with others.

### *System Operator and Ancillary Services*

Since the transmission grid through which electricity flows must be physically managed to ensure operating constraints are satisfied, a **system/grid operator** maintains responsibility for physical operation of the grid and its security and supply quality. To do so it coordinates the actions of grid-connected parties<sup>22</sup> and typically contracts for **ancillary services**, for example, with generators to supply capacity on short notice, or purchasers to allow short-notice interruption of supply, to ensure that supply voltage and/or frequency is maintained within operating tolerances. This can be in response to contingent events such as transmission line outages, generators unexpectedly becoming unavailable, demand being unexpectedly high, other equipment failures, etc. Although such services are typically second-order in magnitude, they are critical to grid security and pose issues of market architecture.<sup>23</sup> In some pools, certain of the services

<sup>21</sup> Zhou *et al.* (2003).

<sup>22</sup> In New Zealand these include generators, distribution companies and certain large industrial users.

<sup>23</sup> Indeed, Joskow and Tirole (2004) note that electricity prices can be very sensitive to small mistakes or discretionary actions by the system operator, with implications for capacity investments (discussed in Meade (2005)).

(e.g. reserves) are competitively determined alongside energy exchanged in the pool. The actual architecture for ancillary services can affect the operation of the pools if the competitive aspects of its provision are not recognised (i.e. it is important that ancillary services and wholesale electricity prices are jointly determined to mitigate issues of market gaming and ensure efficient prices).

#### *Wholesale Markets, Market Operation, Scheduling, Dispatch, and Balancing*

The next main component is the **(spot wholesale) electricity market** itself, whether organised around a **centralised pool** or a more **decentralised power exchange**, comprising some combination of real-time electricity trading, bilateral electricity trading in real time or for future delivery, and other markets to manage electricity price risks (e.g. hedge markets). Through the wholesale electricity market, generators and purchasers come together to determine how electricity demand is to be met in an imminent trading period. In a pool each generator effectively provides its own supply curve to a **market operator/administrator**, which often also takes demand curves from buyers (other times centralised demand forecasts are used). The market operator, as **scheduler**, aggregates this information into market supply and demand curves, seeking to identify the combination of offers and bids that meets demand at least cost while also satisfying any operable technical constraints relating to grid availability and security. The market operator might also be the **dispatcher** that instructs those generators required to meet actual demand arising in real time when they are to generate. As **pricing manager** the market operator centrally determines and disseminates electricity prices. By contrast in an exchange, generators and purchasers contract bilaterally for supply, and to cover any imbalances in supply and demand affected parties are required to pay for top-ups via a **balancing market**, usually managed by the system operator.

Centralised wholesale electricity markets, involving the bulk transacting of power, can be set up with **voluntary (“net”) or compulsory (“gross”) pools**. Under voluntary arrangements parties may also trade bilaterally; with compulsory market participation such trades are precluded. Either way, parties are usually free to enter into financial contracts to manage their exposure to wholesale electricity price movements. From 1 March 2004 the NZEM pool was deemed by regulation to be a compulsory pool, with an exception being the major aluminium producer, NZAS, which has long-term contracts in place for the delivery of electricity.

#### *Wholesale Market Types*

Where pools or other centralised markets are used (such as for ancillary services), generators can be paid a single price representing that which ensures supply and demand coincide – an arrangement known as **“uniform pricing”** – or receive the prices that they bid for each unit of generation they offered for supply – known as **“pay as bid”**. The relative merits of each are discussed further in Chapter 9, but for now it is noted that both approaches are vulnerable to participant “gaming”, and each has its

own implications for the prices expected to result from its application.<sup>24</sup> Wholesale trading can be **real time**, or **spot**, in which electricity is traded in short time intervals (e.g. hourly or as short as five minutes), with this term sometimes being applied to **hour-ahead** or **day-ahead** markets (in which prices are determined in advance of the actual period of supply and demand). Wholesale prices can also be *ex post* or *ex ante*, respectively referring to whether **final prices** are determined after the fact – as in New Zealand when actual demand is known and hence actual prices determinable – or before, in which case additional payments are required to reflect actual market circumstances (e.g. by market participants making payments to a system operator if it buys or sells power to ensure continuous balance of supply and demand, or by market participants accessing a balancing market to cover their own imbalances under a more decentralised approach). Under the *ex post* approach indicative prices are provided up to the time of dispatch.

### *Hedging*

In addition to the spot/real-time market, it is also possible for electricity to be traded in **forward markets**, in which supply is contracted-for in some future period beyond that of the spot market. To manage the risks of wholesale electricity price movements, both contracts for physical electricity delivery and financial contracts referenced off electricity prices can be entered into, collectively known as **hedge contracts**. **Financial hedge** contracts include contracts for differences, in which either party to the contract makes payments to the other based on a relevant reference variable such as the spot price. If such parties transact on the spot market the arrangement serves to fix the price of electricity for one or the other or both at whatever price is struck under the financial contract. **Physical hedges** can include a generator contracting with customers to make physical supply at a fixed price, in the case of residential electricity customers without fixing supply quantities. Finally, to ensure electricity supply security (as distinct from grid operational security) it is also possible for market participants to be contracted to provide reserve generation capacity to be available when called upon whenever supply otherwise offered into the market is short of demand, for example, by the system operator, market operator, some other (e.g. government) agency, or market requirements.

### *Zonal versus Nodal Pricing – Losses and Congestion*

To increase the dimensionality of such markets, elements of the above need not be confined to the national level. Price-setting for the wider electricity system can be decomposed into regional sub-markets (setting **zonal/regional prices**) or further, for example, to the level of individual injection and off-take points around the grid

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<sup>24</sup> See, for example, the difference between uniform-price pay-as-bid auctions described in Chapter 9. The pay-as-bid auction has essentially the same price-determination features as bilateral contracts in that the relevant parties enjoy a measure of pre-determined outcome.

(so-called **locational/nodal pricing**).<sup>25</sup> To account for the fact of transmission losses, **average** or **marginal losses** can be charged to pay for the additional power that must be supplied to meet demand around a grid that has resistance. Under the former, purchasers are charged an averaged allowance for the additional power required to overcome losses. Under marginal-loss pricing, the extra costs of losses relating to given locations determine prices paid by users at those locations, thereby mimicking desirable operation of markets by enabling participants to balance extra resource cost against the benefit of another unit of electricity. The cost of transmission constraints is similarly observable under nodal pricing, with nodes suffering congestion due to constraints yielding electricity prices higher than those without.<sup>26</sup> To help market participants hedge the risk of transmission price rises due to constraints and losses, instruments such as **transmission congestion contracts (TCCs)** or **financial transmission rights (FTRs)** might also be offered and traded.<sup>27</sup>

### *Linkages to Other Markets*

More generally, electricity markets are clearly, if indirectly, linked to many other markets. In New Zealand as elsewhere, the prices of generator fuels such as coal and natural gas (or even oil) interact with electricity-market prices. Given the dominance of hydro-based generation in New Zealand, and the emerging appreciation that competition for available water uses for activities such as agriculture and tourism means that water is a scarce and increasingly valuable resource, Box 2.1 discusses the link between markets for electricity and markets for water. Moreover, the market price of commodities for which electricity costs constitute a major share of production costs (e.g. aluminium smelters) influences whether their producers should demand large amounts of electricity (pushing up electricity prices), or shut down when prices are too high. Thus both input and output markets affect the price of electricity; and distortions in such markets, such as long-term gas contract prices, or lack of market prices for water, will similarly affect electricity markets.

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<sup>25</sup> By virtue of network interconnection the zonal/regional representation of a network can reflect a “hub and spoke” contractual decomposition of the full nodal representation. In other words, a zonal representation can be created by trading around only a subset of nodes, with prices at remaining nodes still remaining informationally efficient. It is interesting that the physics of electricity movement mean that the prices at nodes represent (general equilibrium) economic prices no matter the volumes of offtake or injection at these nodes. Analysis by Evans *et al.* (2003) suggests that the NZEM can indeed be considered an integrated market by virtue of observed correlations between reference and other nodes.

<sup>26</sup> When a section of transmission grid becomes constrained (i.e. operating beyond its technical limits), more expensive generation downstream of the constraint must be substituted for cheaper generation upstream, resulting in higher electricity prices in the downstream region.

<sup>27</sup> Both types of contract pay their holder an amount based on the difference in electricity prices between specified grid nodes at a given level of power flow. FTRs are “revenue adequate” TCCs issued by the grid operator and funded by transmission constraint and loss rentals (see Chapter 9 for more). As discussed in Hogan (1998), the two leading electricity market configurations involve either a pool with FTRs, or a bilateral market with tradable physical transmission rights.

## BOX 2.1

## Link between Electricity and Water Markets

Electricity markets in many countries around the world now have an important role in the scheduling and allocation of generation across load. In addition to their part in electricity allocation, they can play a role in the allocation of water through water markets. Water markets allow secure property rights or entitlements to water to be traded between water users. While some parts of the world have allocated water resources through water markets for a considerable time (e.g. many of the drier western states of the US), markets are becoming more popular as a means of efficiently allocating scarce water resources in the face of increased water demand. Countries such as Australia, the UK, Chile and Mexico have all recently introduced measures to facilitate trading in water rights.

The link between electricity markets and water markets is provided by electricity prices in an industry with significant hydro generation. In spot and longer-term contracts electricity prices provide the value of water on a river with existing hydro-generation. This, in turn, provides a minimum value of a water right for any use on such rivers.

Consider a point on a river upstream of a single hydro power station. At this location, the value of water to the hydro-generator is given by the price at which it sells electricity, less the cost of any resources used (which is very low in the short term when plant is fixed). If the value of water in some alternative use were lower than this price, an efficient water market would ensure water is allocated to the higher valued use of electricity. Hence, the wholesale price of electricity at the relevant network node provides the link to water markets by giving the minimum value of water at points on the river upstream of the power station.

The minimum value of water provided by the electricity market applies both across the country and across alternative electricity generation fuels. The effect across the country is illustrated by the case where hydro-lake inflows have been low in one region and high in others. The price of electricity at any location reflects the higher electricity production in regions with relatively lower scarcity of water, and vice versa. Thus, the price of electricity determines the minimum value of water across different hydro locations.

For the effect across alternative fuels, suppose that gas were setting the price of electricity, then gas will also be determining the value of water in electricity generation. This occurs because if one more unit of electricity is supplied by hydro-generation, the benefit is the price of the gas-supplied generation substituted for. Hence, if the price of gas increases then the value of water in generating electricity would also increase. The value of water in electricity generation is generally no more or less than that of the price of electricity, be the price set by hydro or other fuels.

*Source:* Adapted from Counsell and Evans (2004).

TABLE 2.1		Market Arrangements Compared ...			
Arrangement	England and Wales		Australia	US	New Zealand
	Pool (1990 - 2001)	NETA (from 2001)	NEM (from 1998)	PJM (from 1997)	NZEM (1996 - Feb. 2004)
System/ market operation	Grid owner is also both market and system operator.	Grid owner is system operator. Two independent market operators plus informal markets.	National Electricity Market Management Company (NEMMCO) owned by participating states is system and market operator.	PJM, owned by utilities and non-utilities in its connection area, is independent system and market operator.	Transpower (grid owner) is system operator, scheduler, and dispatcher under contract to NZEM (multilateral contract). Market operator M-Co acts as market administrator, and pricing and clearing manager.
Self-scheduling	0%	98%	0%	64%	20%
Bilateral trading	Disallowed, although bulk of electricity traded is covered by financial hedge contracts.	Yes, by definition. Generators and purchasers trade on forward and futures markets up to years ahead, and through power exchanges closer to actual trading period.	Generally disallowed, although financial hedging permitted.	Allowed.	Allowed, and energy traded through NZEM often hedged.
Demand-side bidding	From 1994 – previously system operator used own demand forecasts.	Yes – generators and purchasers trade bilaterally.	Limited to scheduled/fixed loads.	Yes – most generators and purchasers trade bilaterally.	Yes – generators and purchasers submit offers and bids.
Pricing	Ex ante, day-ahead, spot in half-hour trading periods.	Ex ante, up to years ahead, for half-hour trading periods.	Ex ante, day-ahead, spot for five minute intervals in half-hour trading periods.	Ex ante, day-ahead for hourly trading periods.	Ex post, day-ahead, spot in half-hour trading periods. Final prices posted next day.
Day-ahead market	No.	Yes, by virtue of forward bilateral trading.	No.	Yes (15% of demand), with real-time market (21% of demand) for balancing.	No.

TABLE 2.1 CONT'D		... Market Arrangements Compared			
Arrangement	England and Wales		Australia	US	New Zealand
	Pool (1990 - 2001)	NETA (from 2001)	NEM (from 1998)	PJM (from 1997)	NZEM (1996 - Feb. 2004)
Price cap	1995 and 1996 only.	n.a.	Yes, triggered when NEMMCO intervenes to restore balance.	Yes, in energy and ancillary services markets.	Effectively yes, within limits, from June 2004.
Ancillary services/ balancing	Done by system operator (e.g. contracting for reserve generation, interruptible load, etc), with uplift included in pool price to cover.	Generators and purchasers buy or sell deviations from notified positions from system operator in real-time balancing mechanism at potentially unfavourable imbalance prices. System operator ultimately responsible for balancing via balancing market or by procuring ancillary services ultimately funded by market players.	Done by market (i.e. system) operator via ancillary services contracts, ultimately funded by generators and customers.	Decentralised using automatic control signals to selected generators, since June 2000. Market-based mechanisms replaced administrative and cost-based system.	Done by system operator via ancillary services contracts, with reserve component being reflected in nodal electricity prices.
Losses	Averaged across system and uplift included in pool price.	Averaged across system and reflected in imbalance prices.	Annual average zonal loss factors applied to regional prices.	Marginal losses reflected in prices at each of 1,750 nodes.	Marginal losses reflected in prices at each of 244 nodes.
Transmission congestion hedges	No.	No.	NEMMCO auctions congestion rents.	FTRs (i.e. claims on congestion rents) are auctioned annually.	FTRs mooted.
Reserve capacity	System operator procured via capacity payments.	Excess capacity in 2001 (i.e. reserve margin) was 33%, but wholesale price declines threaten viability of nuclear generation.	Minimum regional generation reserve margins specified by NEMMCO.	Retailers required to own or acquire own peak loads plus around 18% reserve margin.	Electricity Commission to contract for reserve generation and interruptible load funded by industry levy from June 2004.



### *Comparing the NZEM with Other Electricity Markets*

Table 2.1 provides a brief comparison of market arrangements in the NZEM (until 1 March 2004, when the Electricity Commission assumed industry governance and a gross pool replaced the hitherto net pool) with those in a sample of other reformed electricity systems. The New Zealand arrangements are compared with those in England and Wales (both the Pool that operated from 1 April 1990 to 26 March 2001, and the New Electricity Trading Arrangements, NETA, operating since 27 March 2001), PJM, and eastern and southern Australia (National Electricity Market, NEM).

As illustrated in the table, even within centralised electricity pools there can be significant variation in details. The England and Wales pool operating under early reforms represented a much more supply-side-focused arrangement than that in other countries, or under the later NETA. Whereas the demand side played no active role under the initial setup, under all other arrangements surveyed there were at least some electricity purchasers playing an active role – either by submitting bids into a centralised pool or by bilateral and power exchange trades under NETA and PJM; and also by providing interruptible load for ancillary services (the more so under NETA's balancing mechanism which also accesses supply or demand reductions via power exchanges).

NETA, mirroring arrangements in various other EU states, represents the extreme counterpoint (and PJM less so) to the other examples, based around decentralised bilateral energy trading with self-dispatched generation in which both generators and purchasers bear responsibility for ensuring system balance (which remains coordinated by the grid-owning system operator). Centralised market operation is typical elsewhere, in addition to centralised grid management. Significant variation remains as to whether physical trading can occur outside of the centralised markets, and in the scope of the system operator's role. Price caps of various sorts are present in some systems (as in parts of the US, and the Australian NEM). New Zealand's use of *ex post* pricing is an exception: it favours pricing based on actual electricity flows determined after the fact, over price certainty for traders before the fact but subject to *ex post* adjustments.

Even within centralised pools there need be no consistency in matters as fundamental as the nature of offers and bids. Under the England and Wales pool (initially only) generators would submit bids, being complex nine-part offers including separate allowances for fixed start-up costs, a no-load price and a "must-run" flag. In the NZEM, by contrast, these technical factors are internalised in price and volume offers – for example, zero prices are allowed to ensure "must-run" plant is dispatched (e.g. to meet requirements of resource consents for minimum hydro river flows).<sup>28</sup> Pool prices in England and Wales would also include allowances for a number of other factors, such as capacity payments, and uplifts including availability payments and for transmission services (such as ancillary

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<sup>28</sup> At zero prices the right for generation to run is allocated by means of generators' willingness to pay as revealed in a prior "must-run" auction. This mechanism is required for situations of excess supply at zero price.

services). NZEM prices, by contrast, include additional allowances for (as an example) reserve generation,<sup>29</sup> but tend to rely more on nodal pricing to reflect other factors such as transmission losses and constraints.

As discussed in Chapter 4, NETA came about in response to perceived shortcomings in the England and Wales pool operation, particularly as regards the ability of generators to “game” the pool and drive up prices.<sup>30</sup> Similar allegations have been made regarding the NZEM, particularly in winter power shortages (see Chapter 6) and/or when transmission constraints cause the electricity market to fragment, thereby affording generators greater opportunity to manipulate prices (see Chapter 9). The types of strategies used under pool arrangements to increase electricity prices (see, e.g., Bower (2002)) would appear to reflect not only a combination of particular market arrangements (such as the extent and timing of generators’ ability to amend their commitments prior to trading periods, and/or to play off the spot market against the capacity or reserves markets) but also fundamental features of market architecture (such as whether purchasers participate in the pool at all and can therefore react to generator offer prices, whether there is a day-ahead market that contracts generation forward and reduces incentives to game spot prices, and whether the system operator or market participants bear the responsibility for imbalances).

## ELECTRICITY MARKETS – DO THEY WORK?

At the technical level the answer to this question has to be “yes”. After shifting from centralised administration of electricity systems to less planned and more market-based solutions, the lights have not gone off (at least not because of this). It is revealing to see that the decentralised market-based mechanisms adopted under NETA and in PJM have been as effective in terms of supply security as the centralised pool approach adopted by countries and states reforming their electricity sectors. While centralised coordination of the physical electricity system remains the norm via a system operator, electricity markets of varying stripes show that the free-acting forces of supply and demand at a decentralised level can be relied upon to identify trades that enable system balance to be maintained, given suitable market architecture.

A more open question is how well electricity markets work in terms of their goals of providing an effective means for competing generators and purchasers to transact at efficient electricity prices both now and over time. As discussed in Chapter 9, different market arrangements can be predicted to perform better or worse than others, in specific circumstances if not generally, which will be reflected in the level, trend and volatility of electricity prices. And this performance cannot be viewed simply in terms of market architecture; it also should be viewed in the light of broader electricity market structure,

<sup>29</sup> In fact, reserve prices are jointly determined with energy prices in New Zealand so that the trade-off in competitive provision is reflected in their prices.

<sup>30</sup> For a critical analysis of NETA and comparison to the England and Wales pool it replaced see Henney (2001).

participant behaviour, regulation and so on. In this regard the England and Wales re-reform experience is particularly helpful, as its electricity market performance over time can provide greater insight into the effects of changes to mechanisms, industry structure and regulation.

Bower (2002), for example, examines the path of wholesale electricity prices in England and Wales under the 1990-2001 pool and NETA over 2001-2002, seeking to determine whether price declines in the latter period can be said to derive from the change in market mechanism, or reflect the ongoing effects of other restructuring. As shown in Figure 2.4, early prices rose under the pool, and remained higher than the estimated marginal cost of production despite theory predicting they should fall to that level (possibly reflecting a political bias towards coal in the early reforms, but also encouraging unnecessary investment leading to over-capacity). Using statistical analysis Bower finds that the shift to NETA resulted in no significant decrease in prices, except by the removal of capacity payments. The observed price declines were found to be most associated with structural changes (coal plant divestments), increasing use of cheaper imported coal, and overcapacity arising from the construction of new gas plant.<sup>31</sup> Bower surveys the range of early views expressed on the efficacy of NETA, noting that even the relevant regulator has softened its initial positive stance, and concludes that the proposed extension of NETA to Scotland in 2004 is unlikely to benefit consumers (through lower prices) unless the current duopoly in Scottish generation is broken. Zhou *et al.* (2003) report, however, that since the introduction of NETA price volatility has reduced, and the gaming and market-power issues that plagued the former England and Wales pool have all but vanished.

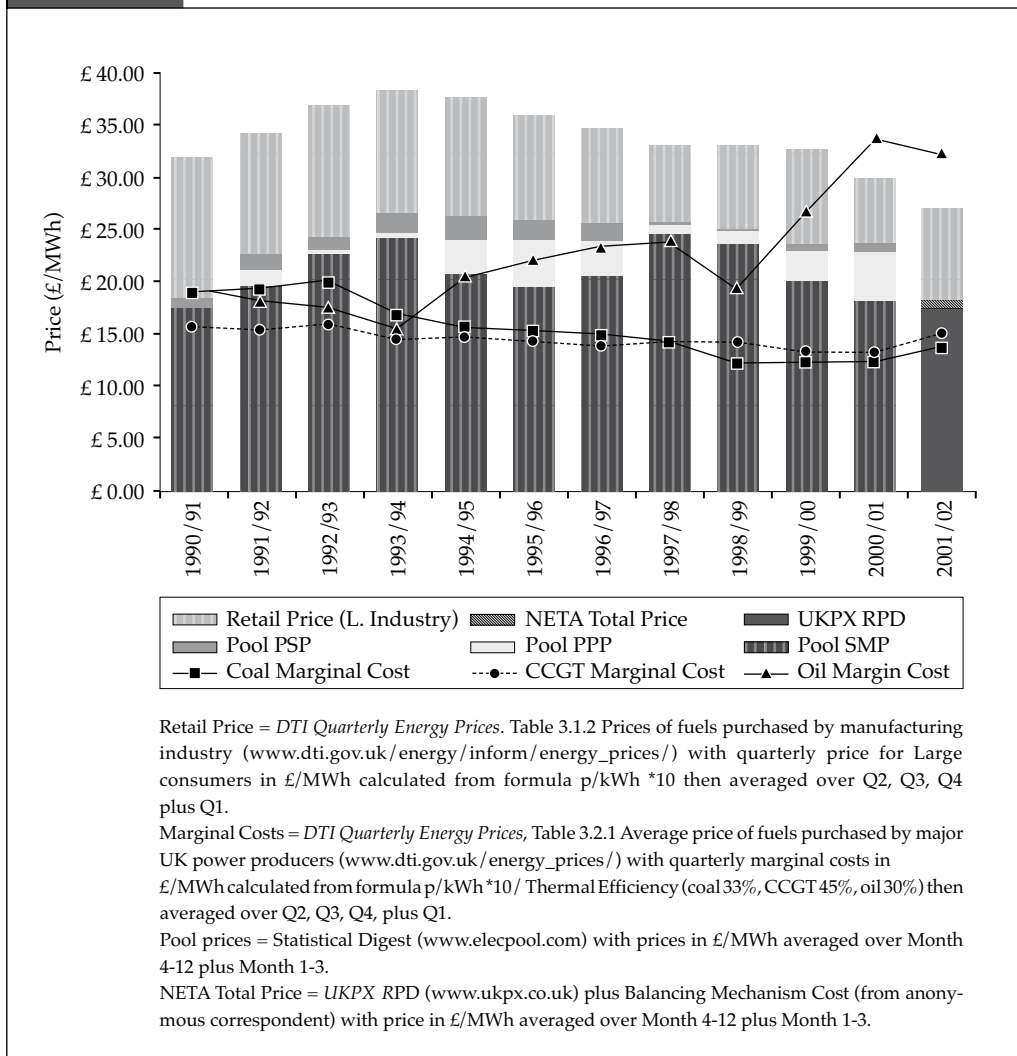
By contrast, Wolak (1997) finds that both market structure and market rules affect the behaviour of competitive electricity prices. Examining evidence from England and Wales (pool), Norway, Victoria, and New Zealand for 1990-1997 (i.e. including less than one year of NZEM operation), he found that electricity systems dominated by fossil fuels rather than hydro power tended to experience greater price volatility within years, as do industries with a larger share of private generation and markets with mandatory participation. Systems dominated by fossil fuels enjoyed greater stability in mean electricity prices across years, reflecting the vulnerability of hydro systems to variations in the weather and the greater degree of integration in international markets for oil, gas and coal. Wolak tentatively concluded that even with large state-owned rather than private firms dominating the NZEM and Norway, prices in these markets appeared to be affected by market power, with large state-owned generators acting as market leaders and other firms acting as a competitive fringe. He found that markets with less government ownership were associated with lower average electricity prices.

Support for the decentralised approach adopted under NETA is provided by De Vany and Walls (1999). Noting that US electricity reforms are tending towards the centralised

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<sup>31</sup> Indeed, wholesale electricity prices fell sufficiently by 2002 that nuclear generation was no longer viable and faced bankruptcy, and some coal and gas generation capacity was withdrawn.

**FIGURE 2.4** England and Wales Mean Electricity Prices and Costs 1990-2002



Source: Bower (2002).

pool approach, they note that such a degree of coordination, given current information and communications technology, is computationally prohibitive (requiring up to 18 hours simply to determine optimal dispatches). Citing the existence in the US of a successful decentralised model operating in the Western Systems Coordinating Council, they explore the pricing dynamics of an interconnected but decentralised network of electricity markets, following unregulated wholesale power prices in an eleven-state trading region. Their results suggest that such an architecture produces stable and efficient prices, and results in a convergence in prices across electricity markets similar to that experienced in the US deregulated gas markets. In other words, decentralisation

is predicted to be an effective approach even in complex networks of interconnected electricity markets, not just within a single system such as that in England and Wales.

Turning to the NZEM in particular, Hogan (2002) described the NZEM arrangements as being in many ways “at the forefront of best practice”, and in terms of its real-time operations “aligned with the best international practice for a competitive electricity market”. He identifies the New Zealand market’s major missing ingredient to be a system of long-term transmission rights (such as FTRs) which are increasingly being employed elsewhere (e.g. PJM and the Australian NEM, which has a form of FTR for interstate connections). FTRs reduce the short-term volatility of prices between nodes, which is particularly useful in markets with marginal loss pricing as it enables the price certainty of hedges at particular nodes to be extended to other nodes without specifying hedges at all such nodes. While NZEM’s use of nodal pricing provides clear signals of the cost (or value) of transmission losses and constraints, the lack of such instruments – which allow their holders to capture a proportion of the benefits of relieving these losses and constraints – is an obstacle to market-based solutions to grid investment.<sup>32</sup>

Market research by the Energy Efficiency and Conservation Authority (EECA (2002)) identifies a desire by electricity users for a firm day-ahead market, in which electricity prices can be locked-in one day forward, allowing sufficient time for consumption plans to be adapted accordingly. Counsel and Evans (2003) support this conclusion, identifying benefits from such a market to include: greater supply security and efficiency, with generators better able to manage their supply commitments (particularly for plant with long start-up times); enhanced demand-side participation and price-risk management (see Chapter 7) – more so than with standard hedging arrangements, since day-ahead markets should be deeper than longer-term forward markets; and reduced incentives for any generator gaming of the spot market because committed forward or hedge prices remove price effects of gaming in the short term.

Finally Evans, Guthrie and Videbeck (2003) examine whether transmission constraints can segment the NZEM and thereby increase opportunities for localised generator gaming or other exercise of market power. They examine the degree of price integration between seven selected nodes in the NZEM for 1997-2002, finding some time-of-day and locational market segmentation, but concluding that the NZEM over the majority of the sample period was integrated. Such findings provide a measure of reassurance that pricing electricity at 244 nodes around a grid subject to sometimes persistent constraints in a relatively small electricity market is not unduly diffuse.

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<sup>32</sup> See Evans and Meade (2001) for an analysis of FTRs proposed for New Zealand. Marginal-loss locational pricing, while appropriately pricing electrical energy lost in transmission, does produce relatively volatile prices in response to changes in demand and capacity, as losses increase at a faster rate than an increase in throughput.

## CONCLUSION

Despite the unusual complications associated with the operation of interconnected electricity networks, engineering difficulties have not proven insurmountable in countries seeking to inject competition and market forces into their electricity sectors. Industry structure has proved as important as market mechanisms and architecture, combining to influence the pricing behaviour in reformed sectors. Importantly, the meeting of engineering and economics – involving the relinquishing of some measure of control by electricity system operators to the anonymous, diffuse and apparently indefinable forces of market-based competition – has not caused the lights to go out. Indeed, as discussed in later chapters (e.g. Chapter 6), evidence exists for system security to have improved under such decentralised administration.

In terms of market mechanisms and architecture, it is arguable that market-oriented electricity reforms have been unduly cautious, with centralised electricity pools initially being the norm and decentralised bilateral exchanges only recently being implemented at the market-wide level. Such a caution is an understandable consequence of long-standing domination of electricity system operation by an engineering preference for control and coordination, and politicians fearful of the lights going off, struggling to balance the equal impenetrability of engineers' caution and economists' optimism about the efficacy of seemingly nebulous markets.

Such caution has commanded a price. The strict centralisation of the England and Wales pool, combined with its initial lack of demand-side market participation, system operator responsibility for balancing, inadequate early structural reform, inadequate market rules, and undue generator discretion, created the perfect "turkey shoot" for generators of a mind to game the market rules for profit. As discussed in Chapter 9, the more the market rules specify detailed elements and constraints, the greater the scope for structural flaws precipitating price manipulation.

NETA might be argued to represent an overreaction to the pool's flaws (although PJM would not), with more efficient pool models having successfully operated in New Zealand and elsewhere (e.g. Norway). But NETA and some other EU state models both demonstrate that an aggressively decentralised market architecture is feasible – allowing network coordination without requiring a centralised market – and that it carries the promise of reduced (and/or transformed, if not eliminated) exposure to any generator market power. At the same time they illustrate the potential for electricity-user participation (e.g. via electricity exchanges), one of the holy grails of electricity sector reform worldwide (see Chapter 7). The complexities of US-wide reform might prove a useful laboratory for the decentralised market approach, particularly if the computational difficulties of the centralised model are not surmounted.

Finally, the performance of PJM/NETA-like systems relative to centralised pool-based systems will be an important area of research, influencing the course of future electricity

sector reforms, both in countries and states already reformed and those whose reforms are yet to commence. As for the England and Wales pool, it is too much to expect that NETA will prove to be the best model of decentralised electricity markets, so future refinements should be expected. The disastrous reforms in the Californian electricity sector, discussed further in Chapter 4, involved a hybrid model of the centralised and decentralised approaches, but flaws in the centralised parts of the system, and some regulatory constraints, most critically contributed to its failure. At present the NZEM is making no moves towards greater decentralisation (in fact Chapter 8 argues the reverse to be true), but for reasons discussed in Chapter 9 there is a case to be made that it should.

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**APPENDIX 2.1 – A BRIEF TAXONOMY OF MARKET TYPES**

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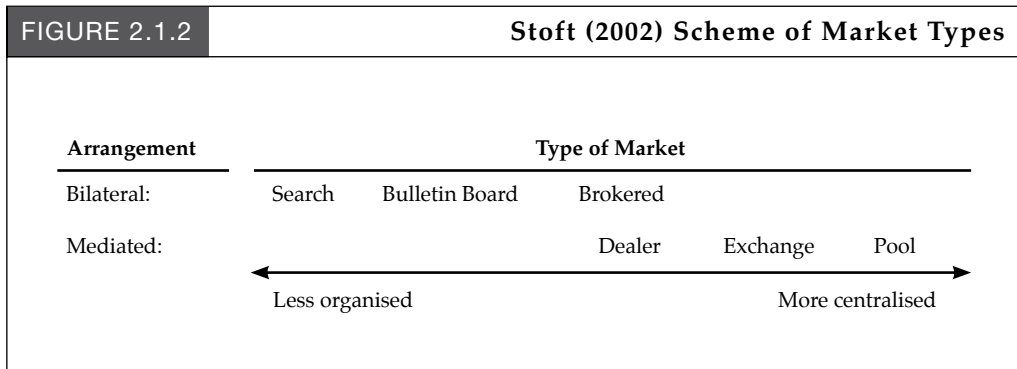
**INTRODUCTION**

Again it is left to Chapter 8 to provide a discussion of the place of different decision-making mechanisms. Here a scheme is proposed – following that of Stoft (2002) – to place the development of electricity markets in context, taking as distinguishing the degree of centralisation or decentralisation implicit in any given set of market arrangements. While “market architecture” is taken to refer to the array of interconnected markets and submarkets that constitute a market-based mechanism of exchange for any particular good or service, “market type” is used to refer to the mechanism that a market uses to determine how exchanges are made (e.g. how price, quantity and quality are determined). As discussed above, “market structure” refers instead to the factors determining whether a market operates competitively or otherwise, such as the number of producers (or buyers), producer behaviour, statutory monopolies, and so on.

**BILATERAL MARKETS**

Markets can be arranged along “mediated” or “bilateral” lines, with associated market types ranging from the centralised to the decentralised (or less organised), as summarised in Figure 2.1.2. In bilateral markets buyers and sellers trade directly, whether privately (i.e. via private “search”), bulletin boards (or websites), or facilitated by a broker (who takes a fee when the parties transact, but is otherwise not involved in the transaction). Such trades involve varying degrees of decentralisation (they might involve only the parties to the exchange or use some means to bring multiple buyers and sellers together to then engage in bilateral exchanges) and flexibility (the parties can set their own terms, do not require a standardised product, etc), but may involve higher transaction costs than other trading mechanisms because of search, contracting and other costs (such as assessing and bearing counter-party credit risk). Since prices are set privately the bilateral approach involves a risk of potential “mis-pricing” (i.e. settling on prices that are not necessarily the best achievable for either party), to the extent that seeking out the best available price involves cost. Furthermore, it typically offers no useful pricing information to third parties who might not even be aware that a trade has occurred. The form of trading will also be affected by the frequency of transactions: the higher the frequency, the more it pays to invest in lower transaction-cost mechanisms of exchange.





Source: Stoft (2002).

## MEDIATED MARKETS

By contrast a mediated market involves a process of simultaneously bringing together multiple buyers and sellers and using some mechanism for determining which of them are to exchange with which others, and on what price, terms and conditions. The dealer will buy and sell from or to participants, which may require the carrying of an inventory of the product being traded. Instead of taking a broker's commission, the dealer instead tries to "buy low" and "sell high", the profit margin on trades being the "spread" (often referred to as the "bid-ask spread"). A key difference between a bilateral broker and a mediated dealer is that the dealer posts prices for buying and selling to potential or current market participants, which provides trading "immediacy" and helps third parties to "discover" and evaluate the current worth of trades to others. By the process of competition and Darwinian survival this should drive prices (and spreads) towards the collective market's assessment of where they should be (versus bilateral trades which should be more expected to reflect private assessments of worth).

## EXCHANGE OR AUCTION MARKETS

Representing a more formal system of organising trades, a so-called "exchange" or "auction market" uses auctions to set the price at which trades take place. As such, this type of market signals the aggregate assessment of traders on the exchange of the traded item's worth, and diminishes the need for potentially expensive buyer and seller search. By acting as counterparty to trades, this market type relieves traders of counterparty credit risk. Through standardising the quality and/or quantity of items traded, and/or the terms and conditions of trades, they can increase the "depth" of the market (i.e. numbers of buyers and sellers seeking to trade), increase competition among both buyers and sellers, and thereby reduce the costs of trading, increase the speed at which trades can occur, and increase the "efficiency" (in the economic "social

optimum” sense) of the price-setting process. Ultimately, the social desirability of the exchange market will depend upon the nature of the transactions: that is, do the savings in search costs and the benefit of more-informed price discovery outweigh costs of standardisation and administration?

## ELECTRICITY POOLS

“Pools” represent a highly centralised form of trading favoured by many countries when creating markets for electricity. More than simply running auctions to set traded prices, they often involve complex optimisations to determine (for example) the least-cost means to configure an array of offers from each of a number of sellers (generators) and bids from buyers (electricity purchasers), possibly at a number of delivery points across a network (i.e. generator injection points and purchaser off-take points), that simultaneously satisfy a range of constraints to do with network security (i.e. to avoid network failures). As such they represent an attempt to bring together competition among buyers and sellers of electricity over a wide geographic area while ensuring that the technical constraints that complicate network operation, to the extent that they are binding at the relevant time, are simultaneously satisfied. While a centralised pool might be thought of as being akin to the centralised “planning” approach to decision-making discussed earlier, the extent of this is constrained by the determination of the rules by which the pool operates. Subject only to those rules each market participant then determines its own trading preferences and approach, preserving the decentralised “market-based” character of the pool.<sup>33</sup>

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<sup>33</sup> Clearly the pool rules could be so broadly defined and/or subject to the influence of (e.g.) a government minister or other form of “central planner” that this distinction begins to blur.

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## APPENDIX 2.2 – DECENTRALISED DECISION-MAKING AND THE NZEM

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### INFORMATION AND ACCOUNTABILITY

Decentralised, as opposed to centralised, decision-making has the advantages that decisions are taken by people who have the best information and who are accountable for their actions. It enables different decisions based upon different information and expectations of the future. In contrast to what happens under central planning, innovation is not limited by bureaucratic rules, and decisions are based upon various decision-makers' assessments and expectations of the future – not just those of the central planner. History, including New Zealand's electricity history, is replete with central-planner failure.

### COORDINATION UNDER DECENTRALISATION

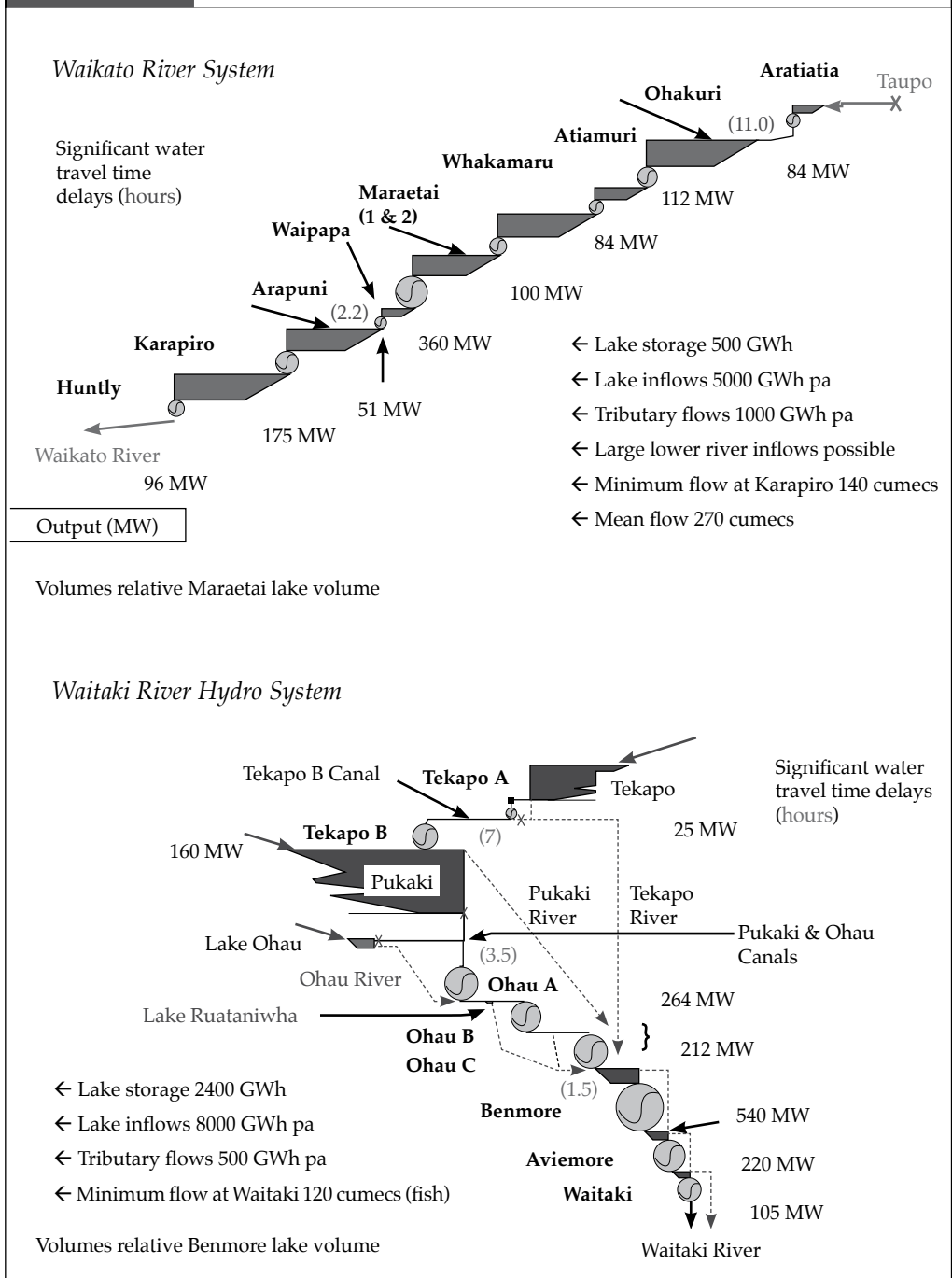
However, as with most goods and services, delivery requires coordination and none more so than electricity. The New Zealand spot wholesale electricity market coordinates electricity delivery from a number of generators and retailers at each instant in time while preserving their ability to innovate and their responsiveness to local conditions and constraints.

Separate generators manage generation on the Waikato and Waitaki rivers, and more than one thermal plant utilises the Waikato River for cooling (see Figure 2.2.1). The generators make their own plans based upon their resources – including stored energy, local resource constraints, their knowledge of the availability of thermal generation and the storage of other river systems in New Zealand, temperature and rainfall, and their expectations of demand, supply and prices. On the basis of these plans they offer generation into the market at the various nodes relating to generation on the river systems.

For offers that are accepted, these generators generate the electricity at the level of those offers under the instructions of the dispatcher. They may also supply reserve generation for frequency and voltage support, and for the management by the dispatcher of unplanned interruptions to supply, demand or transmission somewhere in the grid.

The electricity market enables individual generators and retailers to manage their own affairs in the presence of coordination that matches the production to consumption of electricity. This coordination is characteristic of all markets; the interaction of competition and coordination delivers the quantities and qualities of goods that are demanded at economic prices. For electricity, there remains controversy.

**FIGURE 2.2.1 Coordination on the Waikato and Waitaki River Systems**



Source: Robertson et al. (2003).

## RATIONALE FOR DECENTRALISATION VERSUS CENTRALISED CONTROL

Some suggest that running the electricity sector as a centrally planned monolith would yield superior outcomes because it is under “complete” control by one “person” who has access to all relevant information about factors affecting demand and supply in each relevant sector (catchment) and who can order actions by all participants. Others suggest that the decentralised electricity generation system is less effective than the omniscient planner because forward prices at which supply would be forthcoming in future periods are not available. This is a restatement of the proposition that all would be well if there was a very liquid market in forward contracts for electricity. There is commonly no such market even in financial markets, and although markets will develop it is unlikely that they will achieve the liquidity that some hope for (although Counsell and Evans (2002) argue for a day-ahead market).

In fact, there will be local knowledge that the central planner does not have; and in the decentralised system the state of supply and demand in regions of the country are conveyed and coordinated by hydrological information, virtually all of which is public, and by electricity prices themselves (see Chapter 6). It is true that the state of other fuels (e.g. gas availability) and contracts may not be known by other entities but would be known by the central planner. There is, however, no reason to expect superior coordination by that “person”. Markets coordinate diverse expectations of the future and in electricity this includes expectations (and reactions) about demand and hydrological and thermal fuel supplies. Marrying diverse expectations is key to achieving relatively stable outcomes over time, based on better average expectations – i.e. market prices in a sense diversify expectation-error risks based on market participants’ revealed preferences (whereas the expectation-error risks of a centralised planner are decidedly undiversified). Variations in expectations and actions are valuable: one only has to contrast the outcome relating to the diverse expectations of participants relating to the 2001 water shortage to the planner’s *ad hoc* reactions to a lesser shortage in 1991. Put another way, if a single player in a decentralised system held quite wrong expectations and made (what turned out to be) erroneous choices, that player would have much less influence on the performance of the industry than would a central planner. There is no reason to suppose that the central planner has the superior expectations: history tells us otherwise. Indeed, the relative merits of the competitive, decentralised model are all-the-more apparent when the improved incentives it creates for efficiency and innovation are also considered.



*This chapter begins with an identification of where electricity lies in New Zealand's wider energy landscape and a depiction of how the sector is currently organised. Evidence is then presented on the structure, operation and performance of the electricity sector's major components. Generation is followed by the wholesale electricity market, transmission, distribution, energy retailing, and consumption. Finally, data is presented on the returns accruing to various parts of the electricity sector, including government, over the course of the reforms.*

## INTRODUCTION

To understand New Zealand's electricity reforms it is useful to first understand the main players in those reforms and how they are related. It is also useful to inform any appraisal of the reforms with some evidence on the history of the electricity system's performance.

## NATIONAL ENERGY SOURCES AND USES

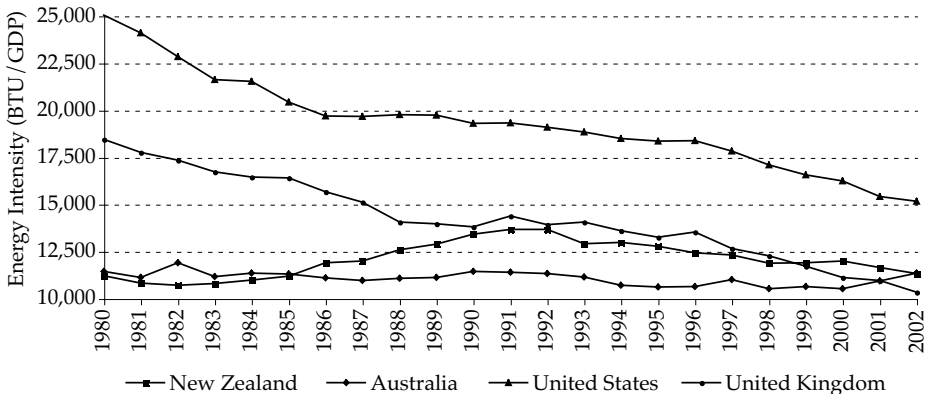
New Zealand's energy use, like that of any other economy, is a function of the nation's constituent activities. As shown in Box 3.1, while the ratio of energy consumption to economic output (i.e. "energy intensity") of New Zealand's economy is less than that of some other economies, it has not been declining in line with trends in those countries, despite the run-down of manufacturing in the late 1980s. The economy's use of energy will have been affected by the cost of energy to consumers, which in turn will have reflected the processes of funding energy supply and the corresponding intrinsic cost of energy in the economy. For energy use to be in the social interest of the economy (i.e. efficient) requires all users of energy to face energy prices that reflect that intrinsic cost. How this is to be achieved in electricity is a recurring theme of this work, but it is just as relevant to the more general question of energy utilisation.

The New Zealand economy relies on a range of energy types from a variety of imported and indigenous sources. While the transportation sector in particular is heavily reliant on imported fossil fuels, the electricity sector derives its primary energy supplies from indigenous sources such as hydro and gas. Renewable energy sources, particularly wind-based generation, have been growing in importance, reflecting both improved technologies and the economics of rising final electricity prices. Unlike most other developed countries (except perhaps France with its significant nuclear energy share), coal provides a relatively small proportion of New Zealand's total energy requirements. Nuclear power is not used at all. Reflecting New Zealand's geological characteristics, geothermal resources also provide a significant source of energy, used mainly in electricity generation.

## BOX 3.1

## Energy Intensity Comparisons 1980-2002

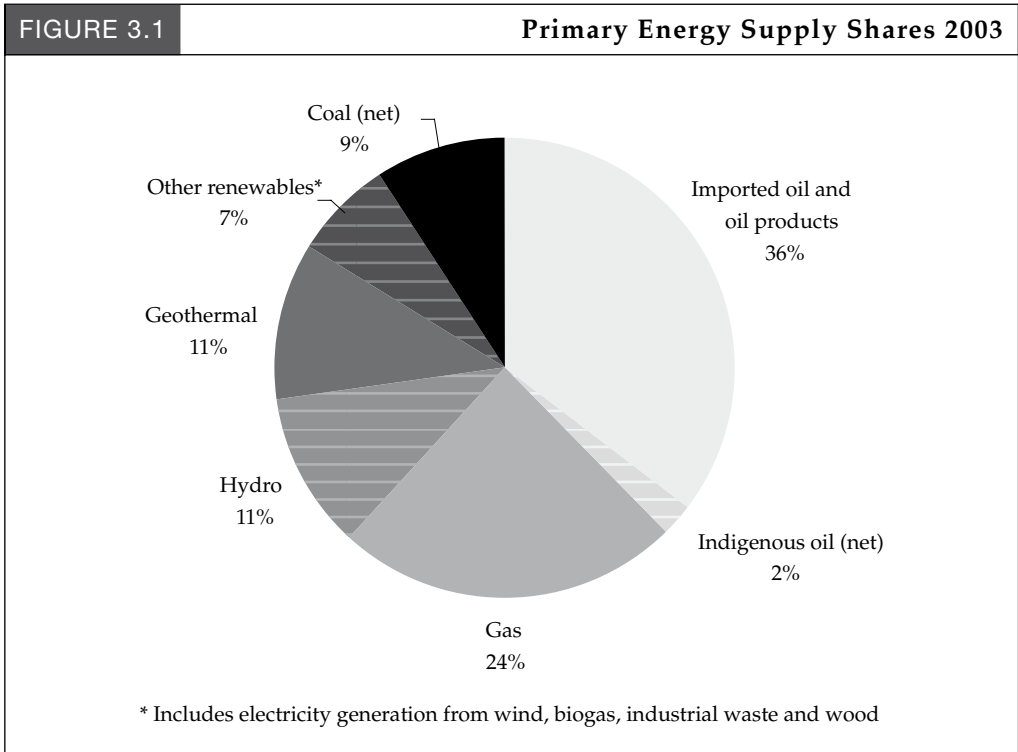
Energy intensity is calculated as the ratio of energy consumption to economic output (Gross Domestic Product, 1995 PPP USD). This simple measure is often used to gain some idea of how efficiently countries are using their energy. The figure below compares the energy intensity of Australia, the UK, the US, and New Zealand from 1980 to 2002. It shows that the US (while still consuming more energy than New Zealand, and the other nations considered, to produce each dollar of economic output) has made sustained improvements in its energy intensity over the last 20 years. The UK has also seen an improvement in its energy intensity and is now at a point where it is less energy intensive than New Zealand. In contrast, New Zealand and Australia have seen a slight increase in their energy intensity over the same period.



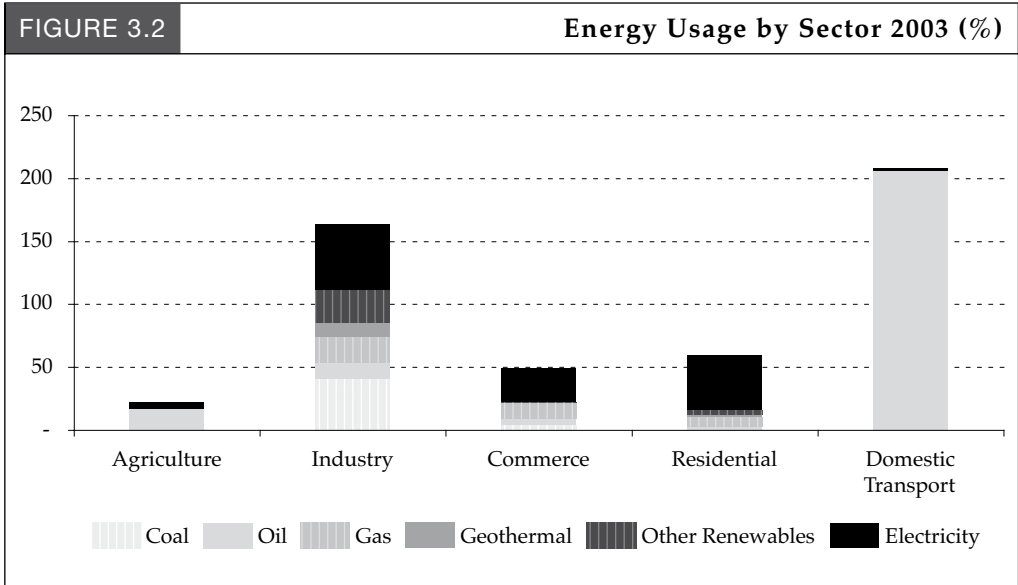
Source: *International Energy Annual 2002*, and *National Accounts of OECD Countries*, Vol. 1, OECD.

These results must be interpreted with a degree of caution as the use of energy intensity to make inter-temporal and international comparisons of energy efficiency is problematic at best. A simple ratio of energy consumption to GDP fails to separate changes in energy efficiency from structural and behavioural characteristics of, or changes in, the economy. Climatic variations present one source of difference. Similarly the energy intensity of a country should improve, all other things being equal, when the economy moves from energy intensive manufacturing to less energy intensive services, although efficiency differences can arise when comparing service industries in different countries. To overcome the distorting effects of structural and behavioural changes on aggregate energy intensity, some authors (Schipper *et al.* (2002)) construct an index of more than 30 energy intensities, all weighted by the 1990 structure of energy use. The study concluded that New Zealand was 17% less energy intensive than the average of the other economies (13 other IEA member countries).





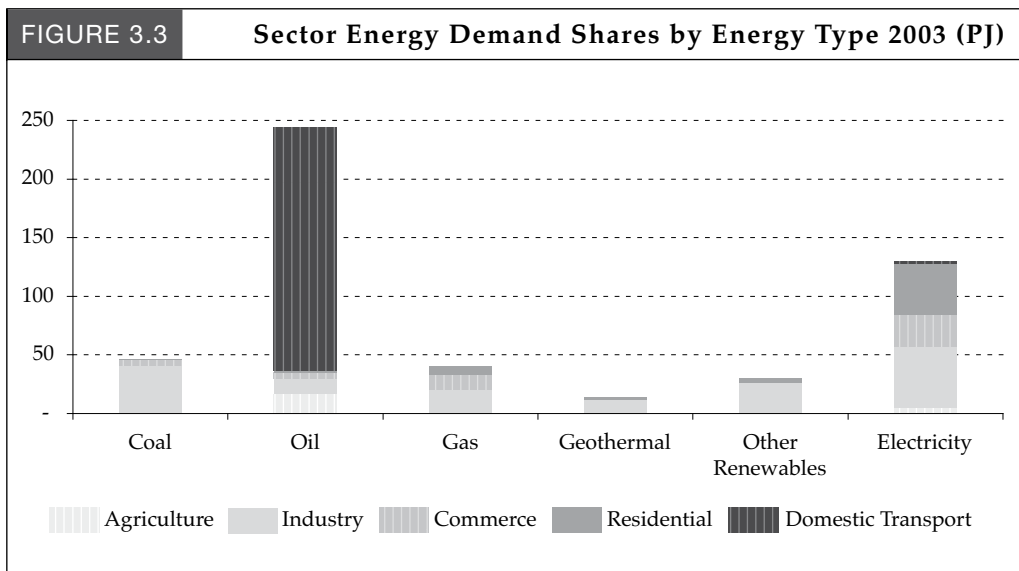
Source: Ministry of Economic Development (2004).



Source: Ministry of Economic Development (2004).

Domestic transportation accounts for the greatest share of total energy usage in New Zealand, followed by industry. While oil is the dominant fuel for most domestic transportation, electricity is used in parts of rail’s main trunk line, and Wellington’s commuter trains and trolley buses. Despite the national economy’s primary-sector dominance, agriculture uses relatively little energy.

Recasting Figure 3.2, it is shown in Figure 3.3 that ultimate energy demands in New Zealand (i.e. net of transformation of energy from one form to another) are predominantly met by oil for domestic-transportation purposes. Electricity is the next-most important energy source, particularly for commercial, residential and industrial use, although less so for agriculture.



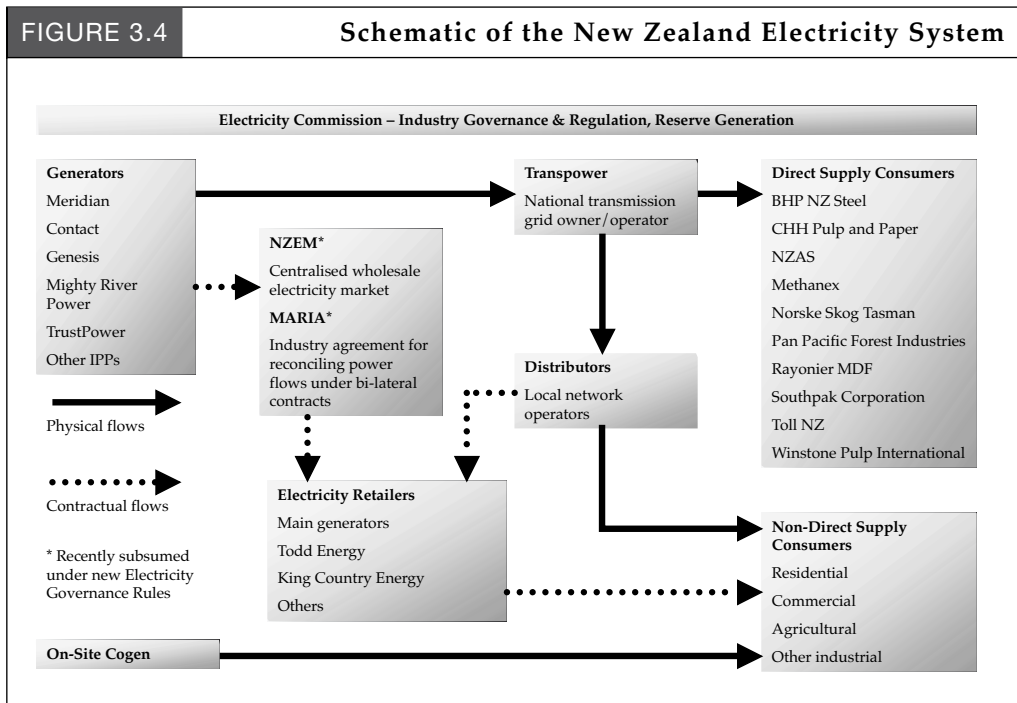
Source: Ministry of Economic Development (2004).

**STRUCTURE OF THE CONTEMPORARY ELECTRICITY SECTOR**

Following almost 20 years of reform, the structure of the New Zealand electricity sector is markedly different from that of even 10 years ago. The generation sector now comprises multiple competing generators. There is an industry-created wholesale electricity market through which around 80% of annual electricity consumed has been sold.<sup>1</sup> Transmission remains a state-owned monopoly, but has been separated from generation and operates

<sup>1</sup> From 1 March 2004 governance of this market was transferred to a newly created government regulator, the Electricity Commission, and market participation became compulsory. Until then it had been voluntary and self-governed by industry.

to make a commercial return subject to efficiency goals.<sup>2</sup> A number of major electricity users continue to contract directly for supply, while most consumers contract for supply with a vastly reduced number of energy retailers. These retailers contract with local distribution companies to deliver physical supplies. Distribution companies – representing local monopoly providers despite franchise area removals, and now mostly owned by consumer (and sometimes community) trusts – have also reduced in number, and since 1999 have been required to specialise in distribution services and be owned separately from competitive activities such as generation and retailing.



Source: Adapted from Ministry of Economic Development (2003).

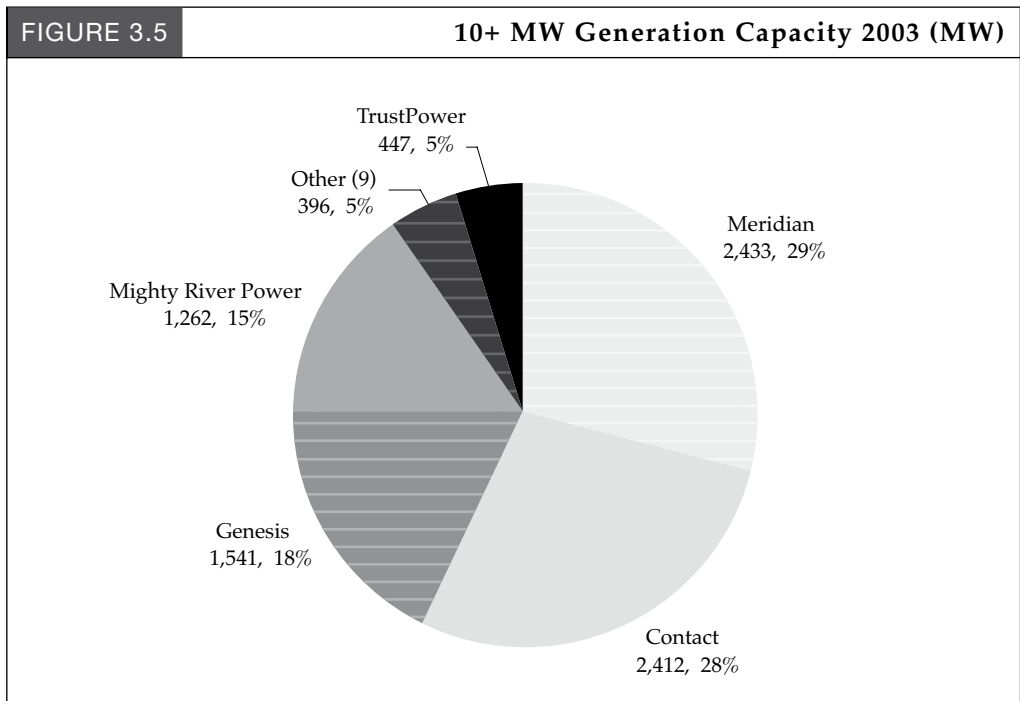
## GENERATION

### Reconfiguration and Ownership

It was not until 1996 that significant competition was introduced into the generation sector, with 28% of the generating capacity of the then state monopoly generator,

<sup>2</sup> Responsibility for transmission pricing and investment decisions also passed to the Electricity Commission on 1 March 2004, from the grid owner, Transpower New Zealand. Accordingly, transmission in New Zealand has passed from a “Transco”-like model familiar in the US to more like that of an independent system operator (ISO), with Transpower retaining ownership of the grid (see Chapter 9 for more details).

Electricity Corporation of New Zealand (ECNZ), being transferred into a new state-owned generator, Contact Energy. The balance of ECNZ's generation capacity was separated into three competing state-owned generators, Meridian, Genesis and Mighty River Power in April 1999. Even with the privatisation of Contact in 1999, generation remains predominantly state-owned, with around 62% of capacity owned by government. Of the remaining 38%, 28% (i.e. almost three quarters) is now controlled by the Australian firm Origin Energy (the majority owner of Contact after it brought US firm Mission Edison Energy's controlling stake in 2004)<sup>3</sup> and the remaining 10% is represented by a mixture of local authority and private investment, mostly domestic. In 2003 total generation capacity (counting plant of at least 10 MW capacity) amounted to some 8,491 MW, and total electricity generated was 39,594 GWh.



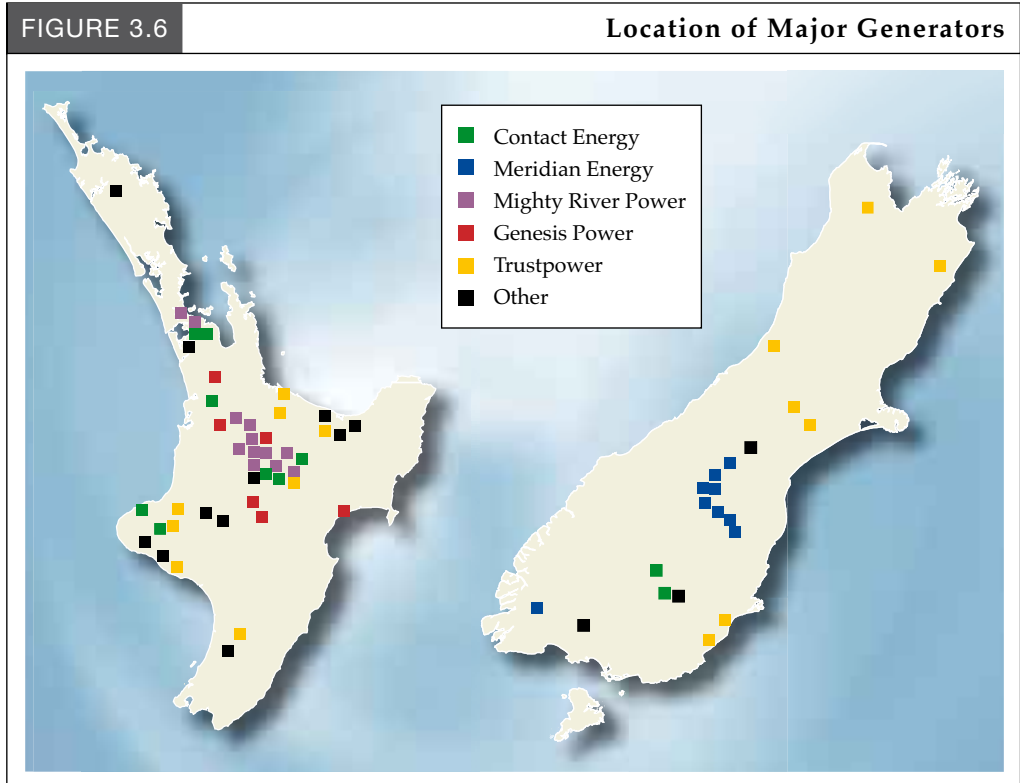
Source: Ministry of Economic Development (2004).

### Location

As shown in Figure 3.6, generation is predominantly located in the North Island of New Zealand, comprising 43 of the country's 64 stations and 58% of capacity. While this bias locates the weight of generation close to the main demand centres,

<sup>3</sup> As a delayed response to the effect of the Californian electricity crisis of 2001, Mission's US parent announced a programme of selling down its offshore assets, including its 51% stake in Contact, to improve its damaged financial structure.

particularly Auckland, significant South Island generation is typically required to service predominantly North Island demands.



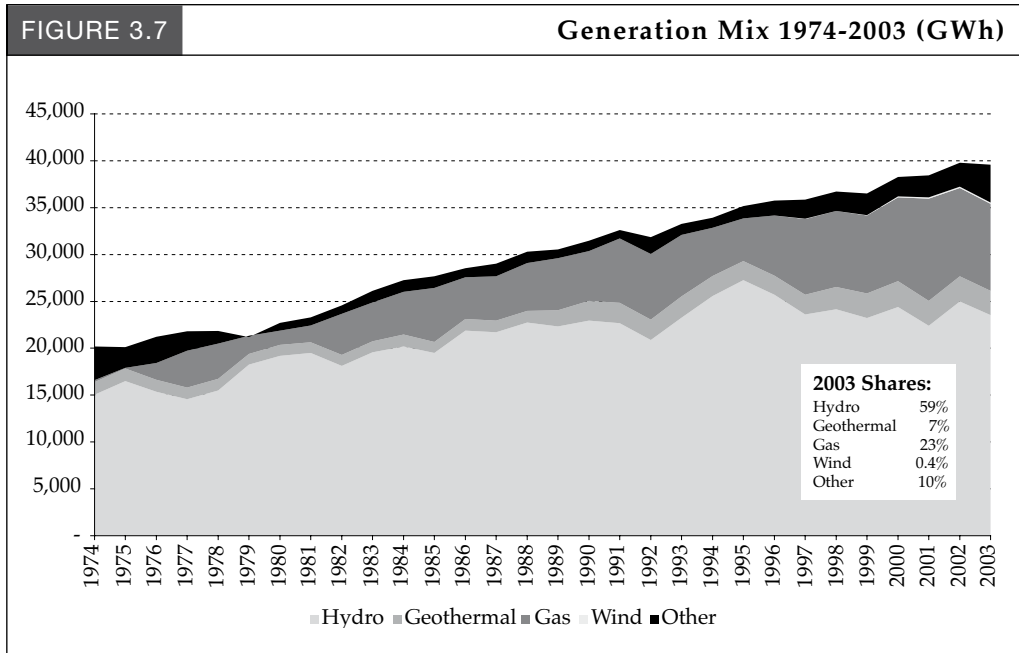
Source: Adapted from NZEM (2004).

Mighty River Power has capacity centred mostly in the upper-central North Island, based on the Waikato River hydro resources. Meridian is also concentrated around hydro resources, particularly those feeding its 710 MW plant at Manapouri and 540 MW plant at Benmore, but is located in the lower South Island catchments. The country's single largest generation asset – the 1,000 MW gas- and coal-fired station at Huntly – also forms the largest part of the Genesis supply portfolio, which includes additional hydro assets in the central North Island and at Waikaremoana. Contact Energy's generation is more widely distributed, with its largest asset being a 400 MW gas-fired station in New Plymouth, but with around 750 MW of hydro capacity located at Clyde and Roxburgh in the lower South Island, and around 325 MW of geothermal capacity in the central North Island.

### *Composition*

Figure 3.7 illustrates the long-term dominance of hydro in New Zealand electricity generation. Geothermal sources have made an increasing contribution to annual

output, but the significant share of demand growth over the past three decades has been met by indigenous gas-based generation, although the main gasfield, Maui, is rapidly depleting. Other sources such as renewables (e.g. wind, co-generation) are receiving increasing favour, but constitute a small part of annual supply.



Source: Ministry of Economic Development (2004).

What distinguishes hydro generation in New Zealand from that in other non-interconnected, hydro-dominated electricity systems is the relative lack of hydro storage, amounting in 1992 to a mere 12% of annual electricity demand, and only around 8% now. It is a result of New Zealand’s physical geography that the locations suitable for hydro development typically have no possibility of economic creation of large lakes. Combined with volatile seasonal hydro inflows, this exposes the New Zealand electricity system to periodic supply shortages resulting from adverse weather patterns (see Chapter 6).

Despite these limitations, in terms of process efficiency – or electrical energy generated as a ratio of energy used in generation – hydro enjoys certain advantages over alternative energy sources. Not only does it produce zero carbon emissions, but it is almost twice as energy-conversion efficient as, and less volatile than, its closest rival, wind, when converted into electricity with then available technologies.

With the downward revision in 2003 of estimated reserves in New Zealand’s main Maui gasfield, greater urgency is being applied to the development of alternative

fields, such as Kupe and Pohokura, and exploration for new fields. The possibility of creating facilities for the importation of LNG is also receiving attention, and out-of-vogue coal is receiving renewed interest. Since an increasing share of demand growth is being met by thermal generation, the economics of alternatives will have important implications for wholesale electricity prices. Indeed, as the marginal generator becomes increasingly gas-based it should be expected that electricity prices will begin less to reflect hydrological conditions and more the price of gas. For so long as domestic gas supplies are sufficient to meet this growing demand, electricity prices will be influenced by whatever contract price is struck for those supplies, which in turn will be driven by the opportunity cost of gas in domestic applications (given it is not economically exportable). Alternatively, the cost of coal-based generation may play an increasing role, as will the level and any changes in Kyoto or other emissions charges. Should significant facilities be established in New Zealand for LNG importation, electricity prices may ultimately come to reflect world gas prices instead.

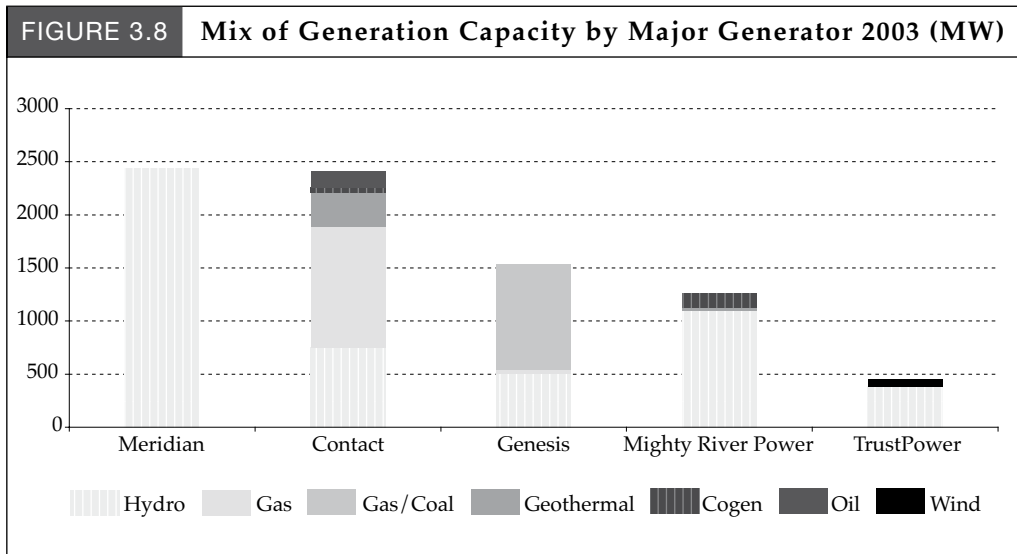
<i>Electricity System</i>	<i>Hydro Share (%)</i>	<i>Hydro Storage as Percentage of Annual Generation</i>	<i>Inflow Variability (%)</i>
New Zealand	75*	12	-30 / +35
Tasmania	99	133	-20 / +20
Iceland	93	18 – 20	-30 / +30
Sri Lanka	80	40	-22 / +22
Brazil	97	785	-67 / +97

Source: Electricity Shortage Review Committee (1992).

Note: \*As shown in Figure 3.7 above, hydro generation has a lower share in 2003 because of growth in thermal generation since 1992.

<i>Energy Source</i>	<i>Carbon Emissions (KT/PJ)</i>	<i>Process Efficiency</i>
Hydro	0	89%
Oil	40	n.a.
Coal	27	35%
Gas	15	34%
Wind	0	45%
Geothermal	1	10%
Total	5	46%

Source: ECNZ 1994 Annual Report.



Source: Ministry of Economic Development (2004).

## SPOT WHOLESALE ELECTRICITY MARKET

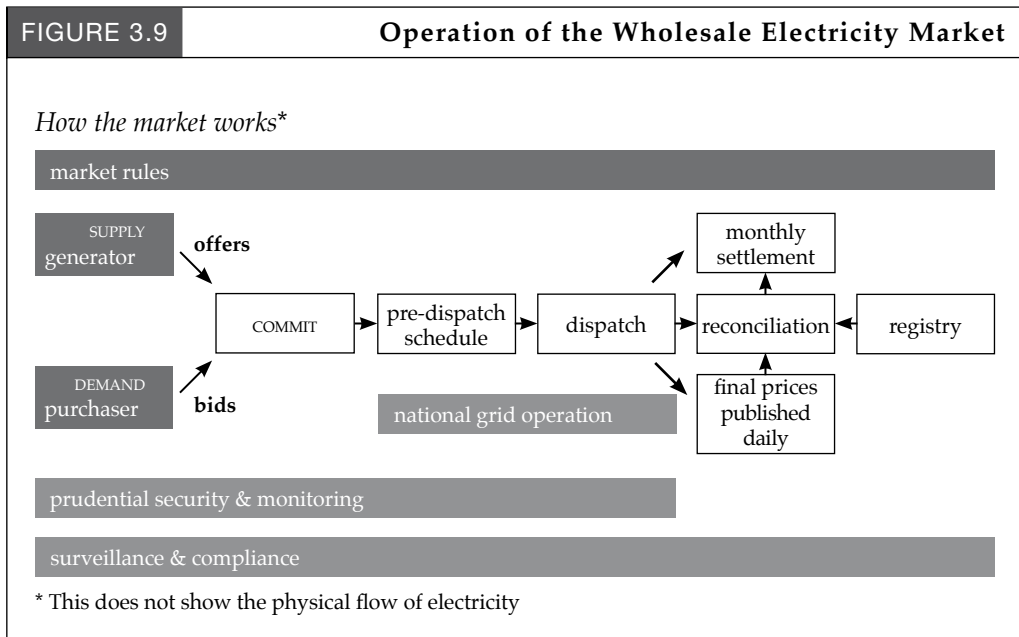
### Structure

The spot wholesale electricity market, also known as the New Zealand Electricity Market (NZEM) and created by industry via multilateral agreement as a voluntary self-regulating market,<sup>4</sup> began full operation on 1 October 1996. Around 80% of all electricity consumed in New Zealand was voluntarily traded through the NZEM, although much throughput is hedged. The remaining electricity was transacted via bilateral contracts between generators, retailers and major users outside of the market. It establishes an agreed process by which a transparent pricing mechanism is used to ensure balance between electricity supplied and demanded in 48 half-hour trading periods in each day, at each of 244 nodes on the national grid. Until March 2004 firms could become spot-market participants by contracting to abide by the NZEM rules (since then market participation has been made compulsory to industry members). Participants in 1996 included purchasers, generators as distinct entities, and traders. Given the restructuring described below, by 2002 participation comprised firms combining generation and retailing.

<sup>4</sup> Self-regulation was administered and enforced by an independent panel. Arnold and Evans (2001) analyse NZEM's self-enforcement provisions, emphasising the importance of effective, neutral, transparent and certain compliance processes in attracting and maintaining NZEM members, given it is a voluntary market with open exit and entry. Despite its voluntary, industry-based origins, responsibility for the governance of the NZEM was assumed by a newly created regulator known as the Electricity Commission on 1 March 2004.



At its establishment the NZEM adopted a set of guiding principles, based on guidelines set down by government, as a framework to assess market participant behaviour and rule changes. The guiding principles required the NZEM collectively to foster efficient and competitive markets, enable the entry of new buyers and sellers, comply with the law, be robust and enforceable, and maintain a process to set and change rules. The general operation of the rules and their evolution was overseen by the NZEM Rules Committee, with compliance monitored by an independent Market Surveillance Committee. These functions are now the responsibility of the new Electricity Commission.

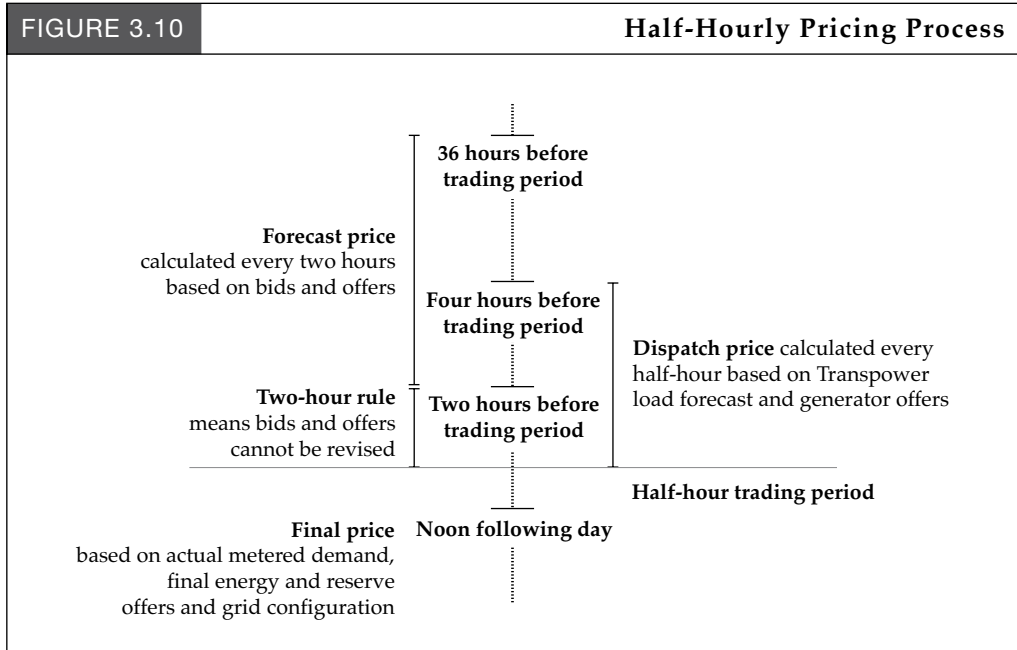


Source: Adapted from NZEM (2004).

### Services and Operation

NZEM services are provided via contestable contracts. The Commodity Information and Trading system (COMIT) provides an internet-based means for generators to submit offers and purchasers to submit bids at each node up to 36 hours before dispatch. Information on how generators are anticipated to meet demands is provided by the **scheduler**, Transpower, which as **dispatcher** also matches actual demands and supplies in real time to ensure physical balance. As **grid operator**, Transpower manages the physical characteristics of electricity supply to ensure system-wide security and supply quality. M-Co – initially set up by industry as The Electricity Market Company and responsible for the development of the NZEM – is the **market administrator**, and as **pricing manager** calculates and publishes final prices based on actual supplies and demands. It also settles the market, acting as **clearing manager**. Reconciling actual supplies and demands and associating these with supply contracts are the responsibility of the **reconciliation manager** d-cypha

(a subsidiary of Transpower), drawing on registry information as to which retailer supplies each point of connection to the electricity system (based on unique connection identifiers known as ICPs). The relevant processes are illustrated in Figure 3.9 above.

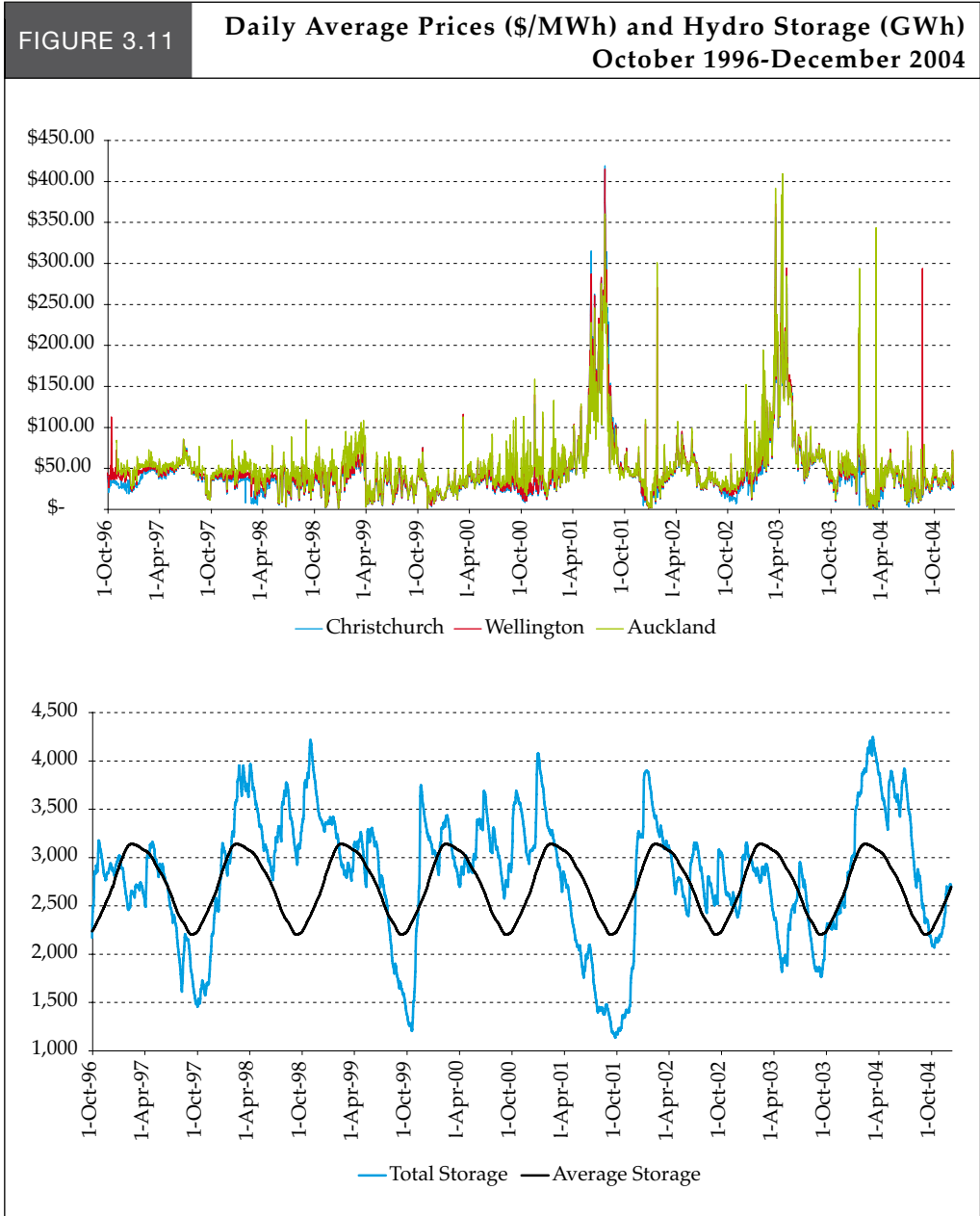


Source: Adapted from NZEM (2004).

### *Pricing and Performance*

NZEM pricing includes a must-run dispatch auction allowing generators to bid for the right to offer generation at zero price to determine the dispatch order when supply exceeds demand at zero price. Such needs can arise, for example, when gas generators have take-or-pay gas contracts, or resource consents require hydro operators to maintain river flows. Initially, final prices were published at the end of each month. Even now, with final prices available by noon of the day following each trading period, significant deviations can arise between forecast and final prices. Real-time pricing for five minute intervals, which more closely matches final prices, was trialled from 2002, but no decision was made for its adoption pending NZEM governance passing to the new Electricity Commission in March 2004.

The pricing history of the NZEM is summarised for the three main centres in Figure 3.11. Of immediate note are the major price increases experienced in the 2001 winter crisis, and 2003 winter scare, although these increases are dwarfed by those experienced in the US midwest in 1997 (see Chapter 6 for discussions). Transitory price spikes have also arisen, primarily because of outages in the inter-island HVDC link. Auckland prices typically exceed those in the southern main centres, because of transmission constraints through the central North



Source: M-Co data (unpublished).

## BOX 3.2

## Wholesale Electricity Prices and the Opportunity Cost of Water

There are inherent difficulties in the estimation of the cost of an extra unit of electricity (marginal cost) produced from existing hydro-electric generators. Although water is seemingly free, its marginal cost is not just the direct cost of converting water into electricity, even setting aside the value of water in other uses. Hydro-electric generation from stored water means that the decision to generate today can affect a firm's ability to generate tomorrow. Consider the generation decision of a hydro-electric generator that has a fixed-price hedge contract of 100 MW. If the generator decides to convert one unit of water into electricity when both lake levels and hydro inflows are low, it will have lower reserves for the future. Suppose inflows remain low, its earlier generation decision may leave the firm unable to meet future demand of 100 MW, and the shortfall would require its recourse to the spot market. When future levels of inflows are sufficiently uncertain and storage is low, the generator should exercise its option to delay utilising water and hence delay generation – even if that means not generating when the spot price exceeds the direct cost of converting water to electricity or even when the spot price exceeds the price the generator is entitled to under the hedge.

In times of low inflows the generator delays generation by not offering certain amounts or by offering them at such a high price that it almost certainly will not be dispatched. The second approach is preferable because it makes the generation available for emergencies, albeit at a high price. However, both approaches reduce hydro-electric supply today: if this reduction is met by additional production by generators using other fuels – e.g. gas, or water in a different catchment – withholding generation may have no effect on price. However, when low inflows are geographically widespread, so much generation may be held back to eke out storage that not all of it can be replaced by other generation; and then spot prices rise, inducing demand curtailment by affected customers. Thus the wholesale electricity price provides the opportunity cost of using water today as opposed to holding back for future generation. When the price is low there is low opportunity cost: when demand is so low that generators must run – e.g. to meet resource-consent restrictions – the opportunity cost may be zero or even negative. Normally, however, the opportunity cost of water will lie at or above the price of alternative fuels: if it is above, then generators with other fuels will be induced to supply (thereby conserving water).

In consequence, the opportunity cost of water is complex to estimate other than through the spot price – because it depends upon the extent of hedges, the state of storage, demand, inflows, and expectations about these factors in the future. The role of the spot price in signalling the inter-temporal value of water is important from society's point of view, which is just as well since storage in the New Zealand system is so low – of the order of seven weeks under normal operation – and hydro provides 60-70% of New Zealand's generation capacity.

Island and across the Cook Strait. Christchurch prices were highest at times during the 2001 winter crisis however, as excess generation in the north was used to supply southern demand while southern hydro storage was low. In fact the highest recorded average daily main centre price occurred in Christchurch in July 2001 at the peak of the crisis. Episodes of very low (i.e. almost zero) prices have been experienced occasionally, generally when hydro storage levels are above average and the peak winter demands have passed. Prices from October 1996 to April 1999 arose when generation comprised Contact Energy and the dominant ECNZ, with the stepped decline in wholesale prices in April 1999 occurring when ECNZ was finally separated into three competing generators.

Box 3.2 sets out how wholesale electricity prices can provide important information about the changing value of water.

Reserve generation capacity (and interruptible load) has now been contracted for under recent reforms (see Chapter 6). Such capacity has not been used exclusively for “dry-year” supply shortages, as originally indicated by government, with reserve generation at Whirinaki being used to constrain spot wholesale electricity prices and/or when grid capacity is lost, thus acting more like peaking plant. These prices are therefore now subject to a limited form of price cap at \$200/MWh.<sup>5</sup> This price compares with an initial cap in 1990 of £2,000/MWh in England and Wales, and A\$5,000/MWh in Australia’s NEM, which was doubled in 2002 with a further tripling recommended in 2004.<sup>6</sup>

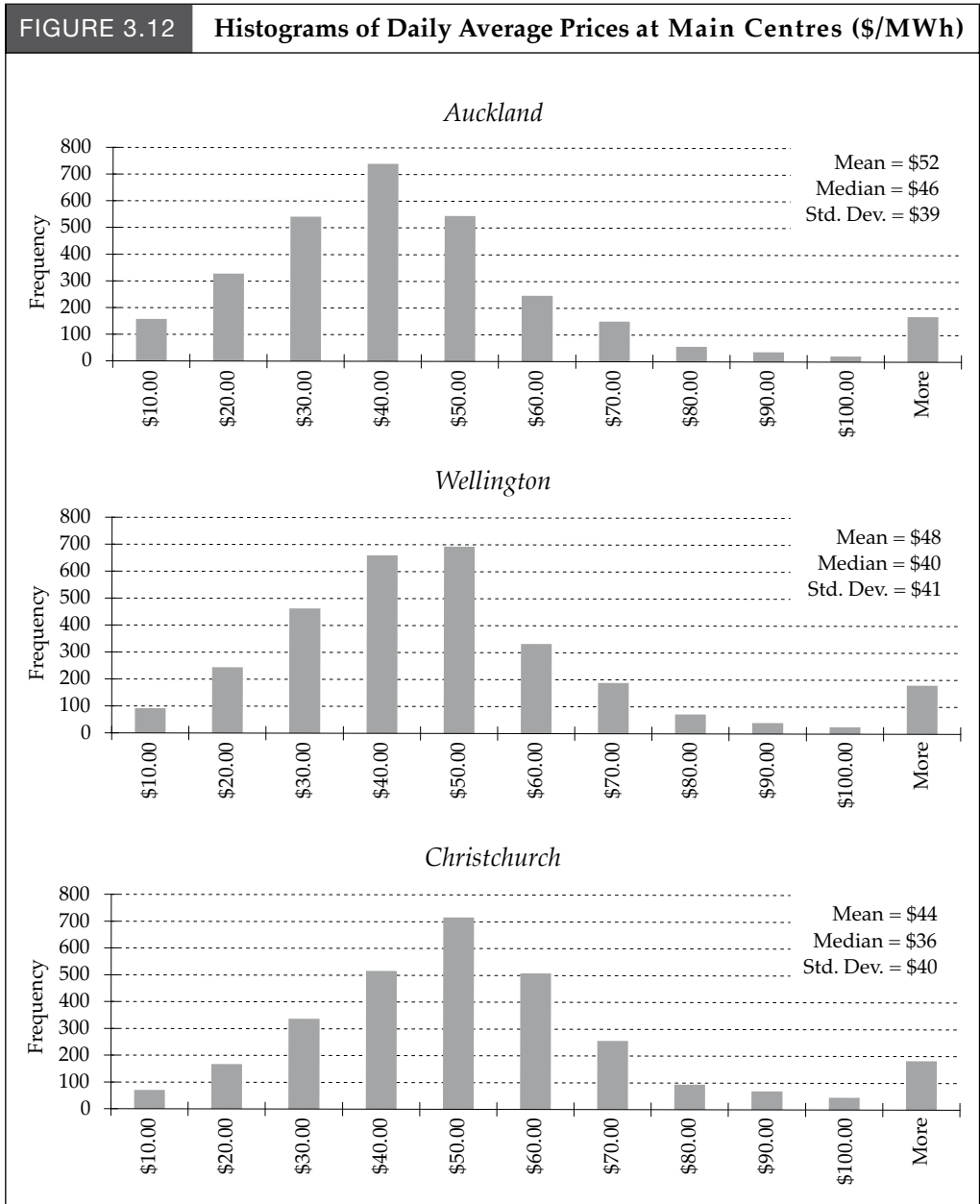
Figure 3.12 depicts the price frequency distributions (histograms) for the daily average wholesale prices at the three main centres. The predicted relativity between prices as electricity is moved north is reflected in the corresponding mean and median prices.

## TRANSMISSION

New Zealand’s high-voltage long-distance transmission grid – comprising some 17,500 kilometres of lines and cables, almost all of which are overhead lines – is long, skinny and sparse. With major demand centres predominantly in the country’s north (NZAS’s aluminium smelter at Tiwai Point, representing 15% of annual electricity demand, and Christchurch being the major exceptions), and major hydro-generation capacity centred in the south, the grid is the critical backbone allowing power to be wheeled from major sources to loads. Central to the transmission backbone is the high-voltage direct-current (HVDC) link between Benmore in the South Island and Haywards at the bottom of the North Island, comprising 570 km of overhead lines and the 40 km underwater Cook Strait HVDC cable. At 350 kV it is the country’s highest capacity power line, and its occasional failure leads to physical separation in the North and South Island electricity systems and their associated wholesale markets. (See Figures 3.13 and 3.14.)

<sup>5</sup> See “Emergency Plant Called into Action”, *Dominion Post*, 22 July 2004, and [www.supplysecurity.org.nz/reserve](http://www.supplysecurity.org.nz/reserve).

<sup>6</sup> See Meade (2005).



Source: M-Co data (unpublished).

The New Zealand transmission grid is also notable for its complete isolation from the electricity system of any other country. Australia is New Zealand’s closest neighbour and it is not currently economic to interconnect the nation’s electricity supply to that of any other country, and so imports and exports of power are precluded. In this regard

New Zealand is to be contrasted with most other developed-country electricity systems; even that of England and Wales has some capacity to trade with Scotland and France.



Source: Adapted from NZEM (2004).

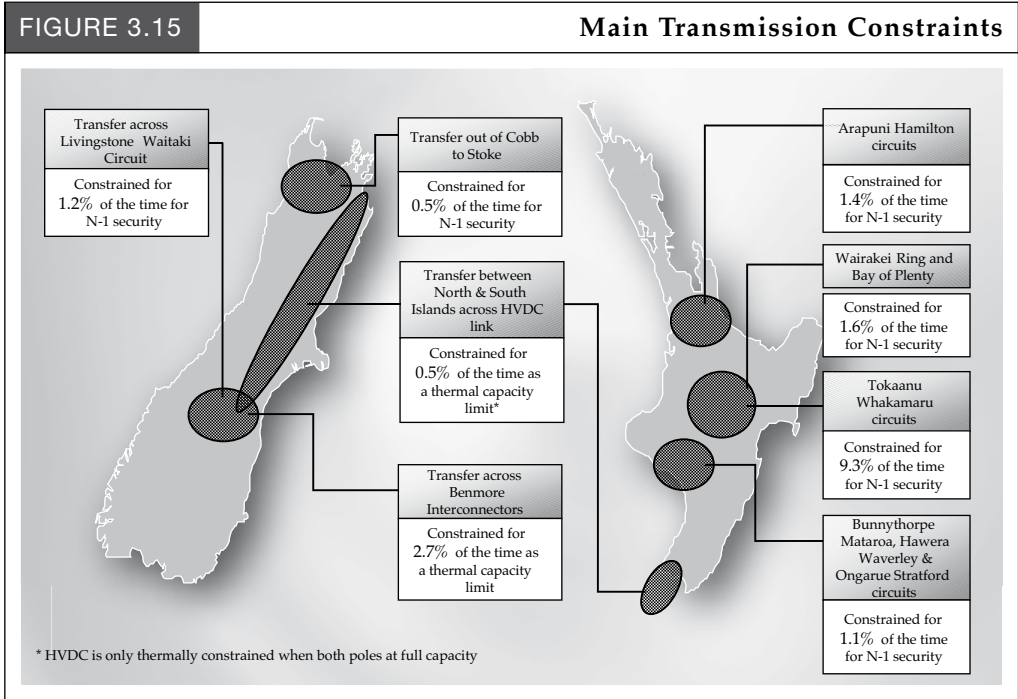


Source: Transpower (unpublished in this form).

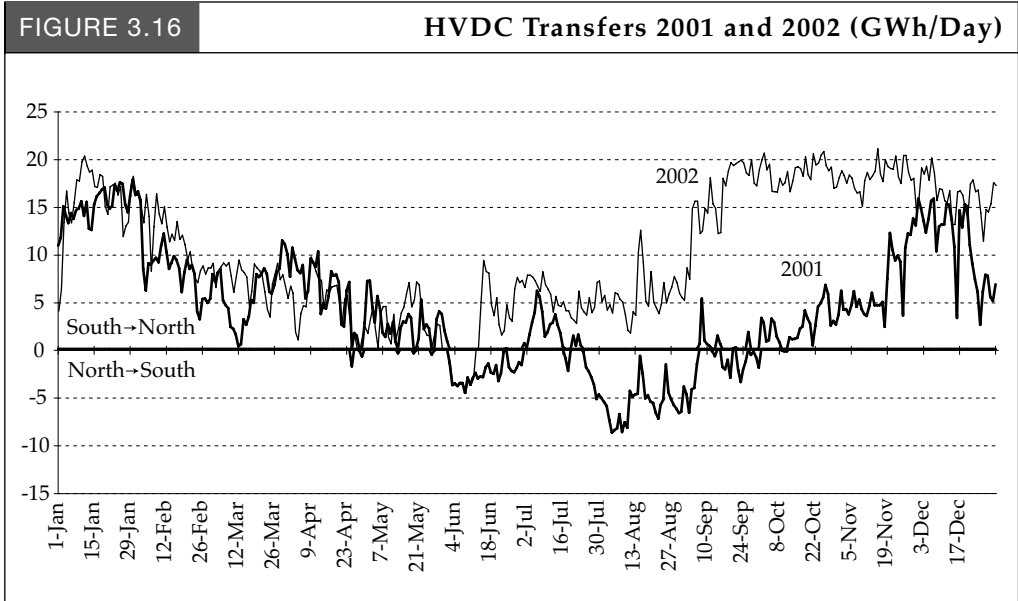
Figure 3.15 shows that the inter-island HVDC link, while important, is constrained 0.5% of the time. The most-constrained section of the grid is located in the central North Island, with grid-security requirements resulting in constraints 9.3% of the time, potentially limiting south-north flows. A result of such constraints is price separation between centres, with those downstream of the constraint facing higher electricity prices than those upstream as more expensive downstream generation is dispatched to meet demand.

While south-north exporting is the norm, occasionally generation in the north is required to meet demand in the south of the country, particularly during winter crises when southern hydro storage is constrained. Such was the case during the winter crisis of 2001. Figure 3.16 contrasts directions of flow across the HVDC link in that and the succeeding, more normal, year.



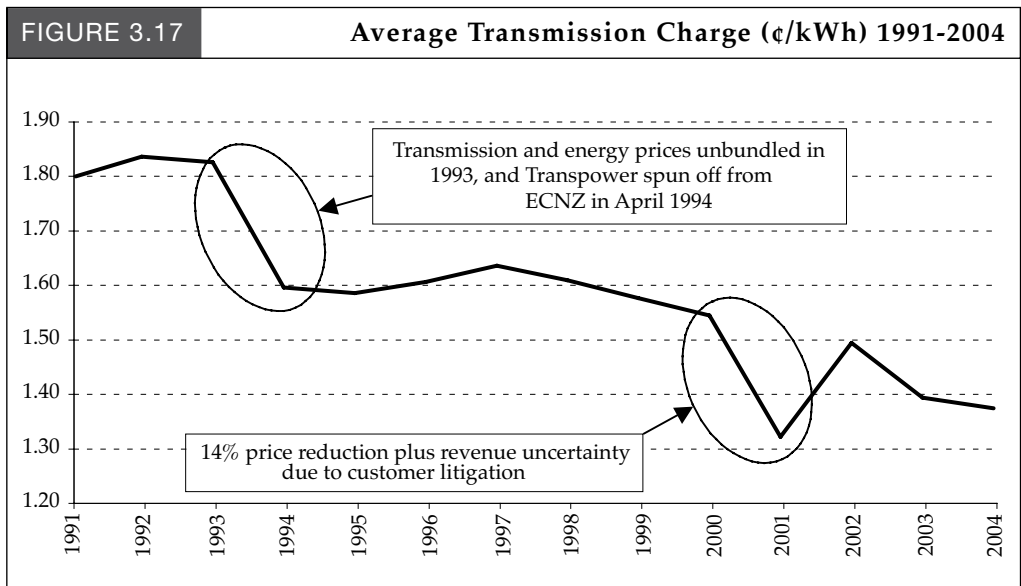


Source: Robertson et al. (2003).



Source: Adapted from NZEM (2002 and 2003).

As shown in Figure 3.17, nominal average transmission charges have trended downwards since early in the New Zealand electricity sector reform process, declining 24% (or 2% annually) between March 1991 and June 2004. In real terms average transmission charges declined by 40% over that period, or by almost 4% per annum. Until Transpower’s legal separation from ECNZ on 1 April 1994, it was vertically integrated with generation; the fall in average transmission charges in 1994 in part reflected the outcome of valuation negotiations between ECNZ and its shareholding government ministers leading up to separation. The decline in year-ended 30 June 2001 average prices reflects both a reduction in transmission charges from 1 April 2001 and uncertainty regarding the likely outcome of a legal dispute over charges between Transpower and Meridian. Resolution of that dispute in the following year explains some of the increase in average charges observed then.

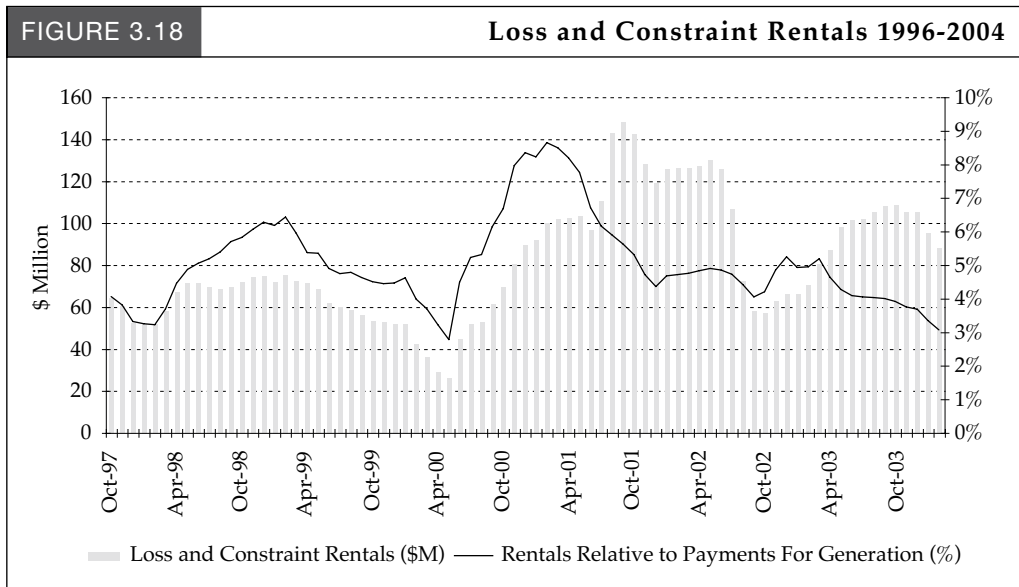


Source: Transpower annual reports, and [www.med.govt.nz](http://www.med.govt.nz).

The operation and performance of the grid is examined in more detail in Appendix 3.1 (with grid investment examined in Chapter 10). Grid performance relates not only to the transmission charges borne by grid-connected parties. Constraints and congestion on the grid not only raise the costs of transmission arising from losses, and the use of higher cost generation, but it also can raise prices by the gaming and market power opportunities that regional separation may provide (see Chapter 9). These issues can be examined by consideration of loss and constraint rentals and other indicators of grid non-performance.

Loss and constraint rentals arise because losses – energy dissipated as heat due to the electrical resistance in transmission components – rise faster than grid throughput (losses

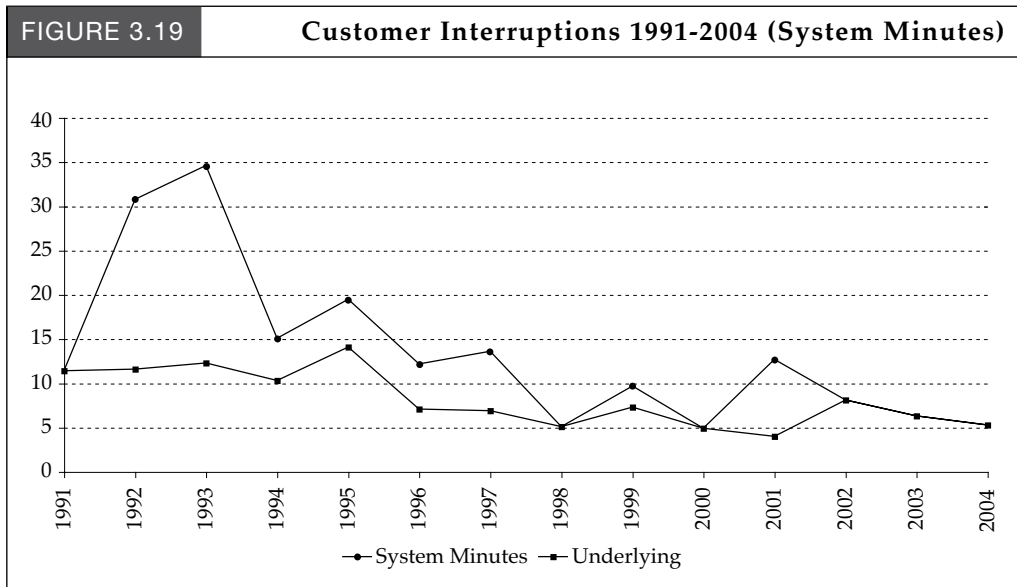
are quadratic in energy), and because constraints mean that prices are above what is required to induce the delivery of electricity to that point. It would be uneconomic to build a grid with such capacity that it had no constraints or losses. Because loss and constraint rentals are generated by the spot wholesale electricity market, rental records are available only since October 1996. They are described in two ways in Figure 3.18. The first is their nominal level over the previous 12 months, and the second is expressed as a proportion of generator payments, also over the previous 12 months. They combine to indicate that, while there has been an increase in loss and constraint rentals since the inception of the spot wholesale electricity market, this increase is a result of higher prices and not a result of increased congestion. Because loss and constraint rentals increase faster than throughput on a given grid, increasing congestion would appear as an increase in these rentals as a proportion of payments to generators.<sup>7</sup>



Source: M-Co data (unpublished).

Figure 3.19 supports this conclusion using a grid-reliability measure, indicating that grid reliability has on the whole improved over the past ten years. System minutes is the sum of non-served energy multiplied by duration, divided by system peak loading. It estimates average system interruption time weighted by the size of interrupted load. The series “Underlying” is the system minutes for cessations of supply that lasted less than one minute. Notably there has been an improving trend in interruptions following the separation of Transpower from ECNZ in 1994, despite the obvious loss of technical coordination between generation and transmission which that separation entailed.

<sup>7</sup> This ratio takes out any price effect, so changes in it over time reflect the increase of constraints and losses only.



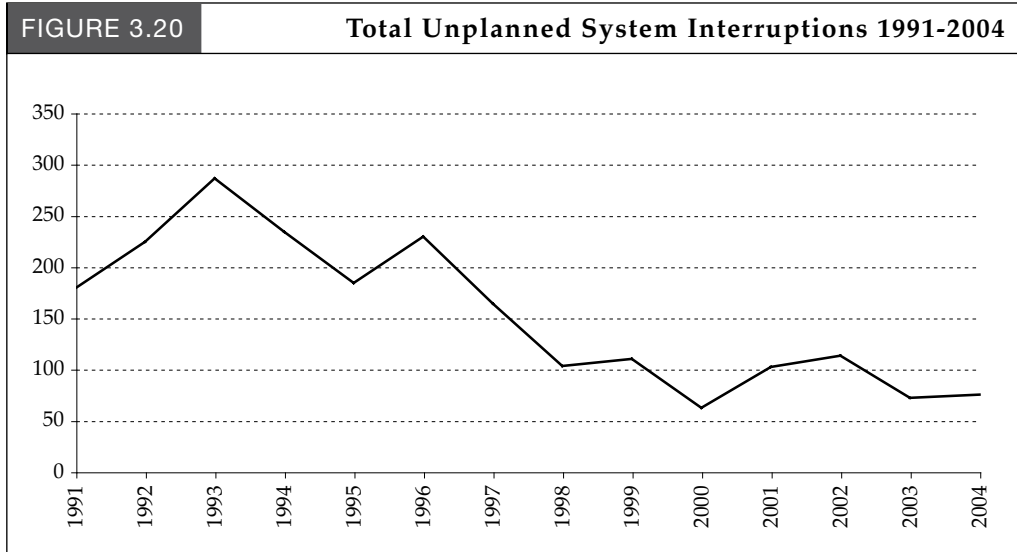
Source: Data from Transpower quality performance reports (various years).

Figure 3.20 illustrates the history of unplanned transmission system interruptions between 1991 and 2004. The “number of interruptions” is a total of the interruptions of supply to Transpower customers. A single event may affect two customers, so would be counted as two interruptions. Reliability is measured by the energy supplied divided by the sum of the energy supplied and not supplied. This too illustrates a general improvement in grid performance, particularly in the latter part of the period.

In short, the grid seems to have maintained or improved its performance despite a 15% increase in peak electricity demand over the past decade.<sup>8</sup> This reflects variations in peak and normal demand that do not necessarily occur in the same locations over time and hence utilise the grid differently. Further, in reacting to locational price signals, generation has been located closer to demand – as in the case of Otahuhu B (a 350 MW gas generator built near Auckland). In addition, Transpower has made some minor investments in the network that will have had some effect. Whatever the balance of reasons, the performance of the grid has if anything improved overall since the advent of the New Zealand spot market. This is not to say that there are not issues about specific elements of the grid and about the timing of maintenance and investment – and perhaps capacity. These issues are important because they affect reliability and because a small imbalance in demand for throughput relative to the capacity of the grid would have a considerable effect on the cost and availability of delivered electricity, in part, because of the nonlinear elements

<sup>8</sup> Meyrick Associates (2003) place no weight on their estimate of a decline in productivity for Transpower because of data problems that are difficult to resolve in such networks, and that arise from different approaches to network valuation adopted by the company during the period.

of the system reflected in pricing (i.e. transmission losses, being quadratic in energy). Transmission investment issues are considered further in Chapter 10.



Source: Data from Transpower quality performance reports (various years).

## DISTRIBUTION

### *Composition and Ownership*

Immediately prior to the contemporary reforms, New Zealand's electricity distribution sector comprised some 47 licensed franchise areas (ranging in size from five square kilometres to almost 29,000 square kilometres). Servicing these areas were statutory electric power boards (EPBs) and a handful of local-council owned municipal electricity departments (MEDs) in major cities – together these constituted electricity supply authorities (ESAs) and supplied electricity retailing, distribution and other services (such as electrical appliance sales). EPBs comprised a mixture of both urban and rural users, reflecting their origins as a means of using cross-subsidies from densely populated supply areas to encourage the development of distribution assets to more sparse and less economic rural areas.

With the corporatisation of ESAs in April 1993, ownership of distribution assets was transferred mainly to electricity consumer trusts and sometimes community trusts, although two cooperatives and limited private ownership through share listings also resulted. The removal of franchise areas resulted in rationalisation in places, with 28 electricity lines businesses now distributing electricity to consumers in New Zealand (see

Figure 3.21).<sup>9</sup> The three largest current concerns in terms of system length, system assets and connection points are Vector (taking in Auckland and Wellington), Powerco and Orion (taking in Christchurch). Current distribution company ownership arrangements are summarised in Table 3.3.

Distribution rationalisation did not result in uniformity, however, and there are wide disparities remaining in distribution company characteristics. Nelson Electricity has just 242 km of lines while Powerco has almost 25,000; The Power Company has only 4.2 connections per line km whereas Nelson Electricity has 35.6. With the enforced separation of lines-business ownership from competitive activities such as retailing and generation in 1999 (see Chapter 5), retailing assets were sold to generators and distribution companies became solely lines operators – now called Electricity Lines Businesses (ELBs) – although limited investment in distributed generation is permitted (especially where renewable energies are used) and, under 2004 legislation, unlimited ELB ownership of reserve generation capacity is also permitted.

### *Financial Performance*

While it is possible for some larger electricity users to connect to lines operators whose network boundary abuts that of their local operator, and while there are some spots of competition with Transpower, in general the provision of distribution services is neither contestable nor competitive – at least not until self-generation and/or economic storage of electricity become feasible at the typical consumer level. As such, lines businesses have until recently been subjected to light-handed price regulation in the form of specified information disclosures under regulations first promulgated in 1994. Under that regime, particular regard was paid to the optimised deprival value (ODV) of lines operator system assets and the economic return that operators earned on such assets.

Representing an assessment of the value of only necessary system assets in their current condition – thereby removing the value of any surplus or overvalued assets – a lines operator's ODV provided an asset base upon which an economic rate of return (typically the weighted average cost of capital, or WACC) could be applied to provide a comparison with actual returns. Initially using a measure called the accounting rate of profit (ARP), but now using a comparable measure known as return on investment (ROI), it was expected that lines operators charging excessive prices would be exposed to various forms of corrective pressure if they disclosed ROIs in excess of some threshold level of WACC. Alternatively, those operators sacrificing quality for profit would be identified by disclosure of certain performance measures. Figure 3.22 provides an indication of the variation in lines-company returns and prices.

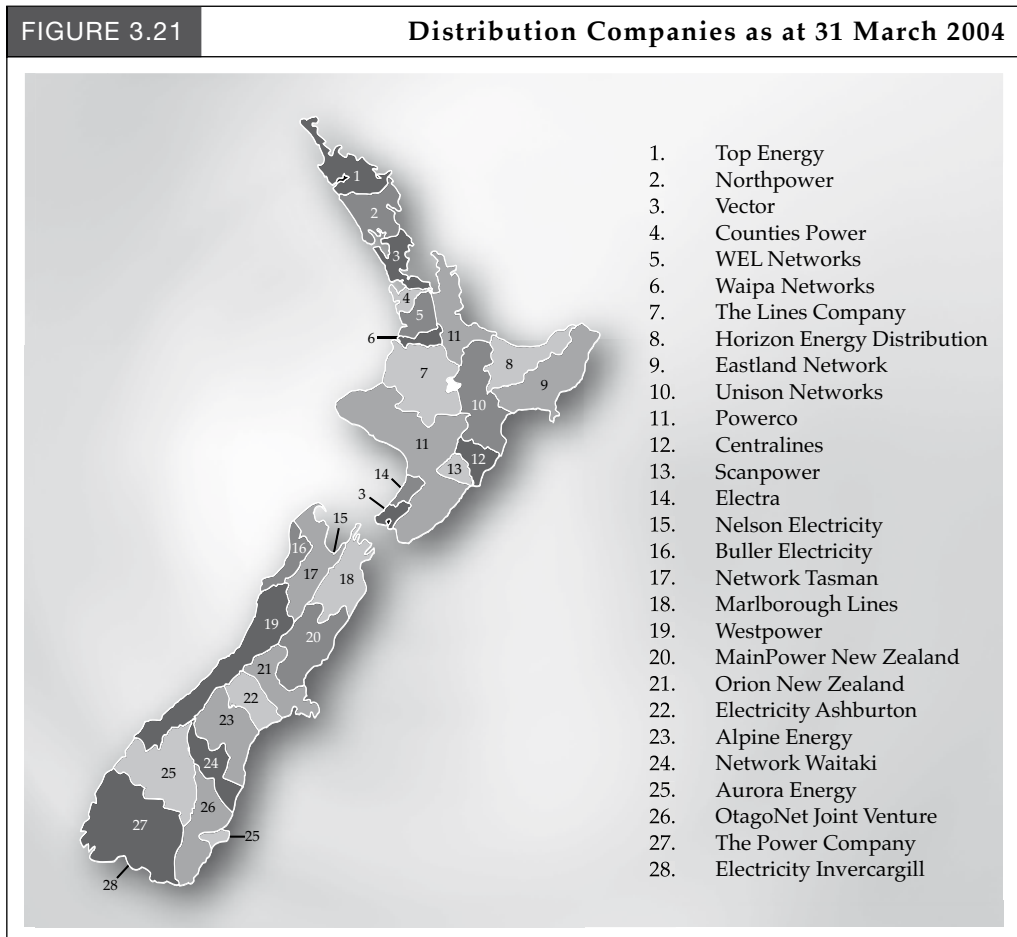
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<sup>9</sup> This compares with the current nine distribution companies in England and Wales, down from 12 at the beginning of reforms in that system, and five (down from 29) and six (down from 25) in Victoria and New South Wales respectively.

<i>Distribution Company</i>	<i>Ownership Type</i>					
	<i>Consumer Trust</i>	<i>Local Authority</i>	<i>Community Trust</i>	<i>Public</i>	<i>Cooperative</i>	<i>Other</i>
Alpine Energy	40%	60%				
Aurora Energy		100%				
Buller Electricity	100%					
Centralines	100%					
Counties Power	100%					
Eastland Network			100%			
Electra	100%					
Electricity Ashburton					100%	
Electricity Invercargill		100%				
Horizon Energy Distribution	77%			23%		
Mainpower New Zealand	100%					
Marlborough Lines	100%					
Nelson Electricity*						100%
Network Tasman	100%					
Network Waitaki	100%					
Northpower	100%					
Orion New Zealand		100%				
OtagoNet Joint Venture**						100%
Powerco				100%		
Scanpower	100%					
The Lines Company	100%					
The Power Company	100%					
Top Energy	100%					
Unison Networks	100%					
Vector	100%					
Waipa Networks	100%					
WEL Networks			100%			
Westpower	100%					

Source: PricewaterhouseCoopers (2005), and some distribution companies or their owning bodies.

Notes: \* Nelson Electricity is equally owned by Marlborough Lines and Network Tasman. \*\* OtagoNet Joint Venture is 51% owned by Marlborough Lines, and 24.5% owned by each of Electricity Invercargill and The Power Company.

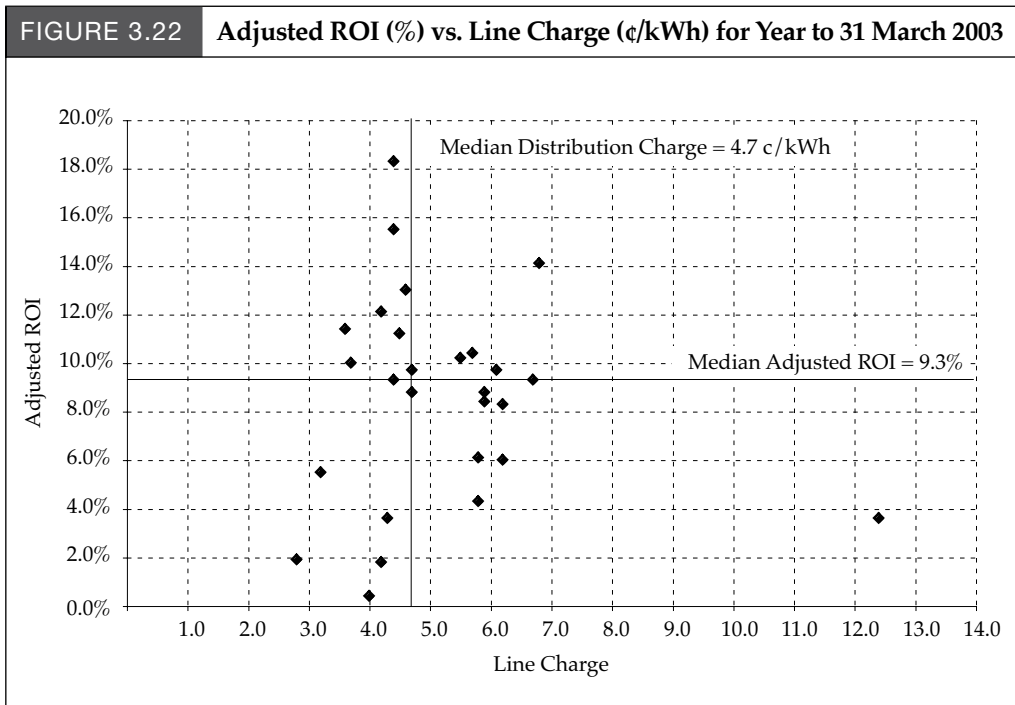


Source: Adapted from PricewaterhouseCoopers (2005).

As indicated, there is little correlation between observed distribution charges and distribution company returns. Some companies would appear to be particularly efficient, charging low prices yet enjoying high returns. Others exhibit the reverse, with high prices and low returns, although this may be more a reflection of system configuration – as much historical and geographical accident as it is operational deficiency. Even in the more central cluster of observations there is significant variation in observed prices and returns. Note that the medians noted above compare with a median line charge of 4.7¢/kWh and median adjusted ROI of 28.1% in the year to 31 March 2004 because of a revision in ODV guidelines as to replacement costs for fixed network assets, which previously had been significantly below current replacement costs. These regulatory revisions resulted in significant upward ODV revaluations with corresponding effects on ROIs (since by definition they incorporate revaluations).<sup>10</sup>

<sup>10</sup> See PricewaterhouseCoopers (2005) for definitions of key performance measures such as ROI.





Source: PricewaterhouseCoopers (2003).

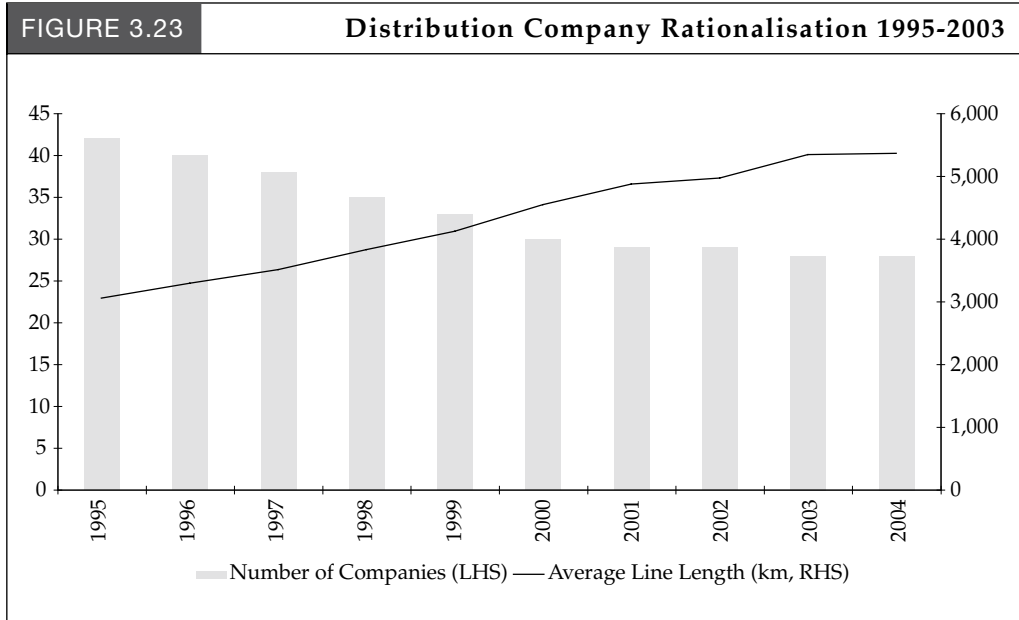
Note: Adjusted ROI is return on asset ODV inclusive of post-tax consumer discounts/rebates.

It can be argued that a lack of convergence in prices and returns under the ODV methodology is a consequence of that methodology. There are two reasons for this. First it is very difficult to plausibly model the cost structures of networks that are so varied in their topography, population density and customer structure in ways that enable cross-firm comparisons; and cost relative to price is affected by the hard-to-measure state of existing networks. Second, it provides limited incentive for efficiency gains to lines operators, although arguably more than that of rate-of-return or its cousin, CPI-X regulation. The recent imposition of CPI-X price controls on lines operators is discussed in Chapter 9.

#### *Operational Characteristics and Performance*

Distribution sector rationalisation typically involved adjacent but sometimes even discontinuous lines operators merging to achieve economies in head office, billing and maintenance in particular. Accordingly the number of operators declined, and average system lengths rose. In part such mergers – spearheaded by operators such as Vector and Powerco – were also motivated by an expectation that larger combined lines and retailing operations would enjoy economies in energy procurement. However, the ownership separation of lines from other activities enforced in 1999, with the resulting acquisition of retail customer bases by generators, diminished this incentive for further

rationalisation. More-narrowly defined operating efficiencies are nevertheless still being achieved through network management being outsourced or joint ventures.<sup>11</sup>



Source: Annual information disclosures ([www.med.govt.nz](http://www.med.govt.nz)) and PricewaterhouseCoopers (2005).

Table 3.4 highlights the wide variation observed in distribution-company operating and reliability measures, mirroring that observed for financial performance.

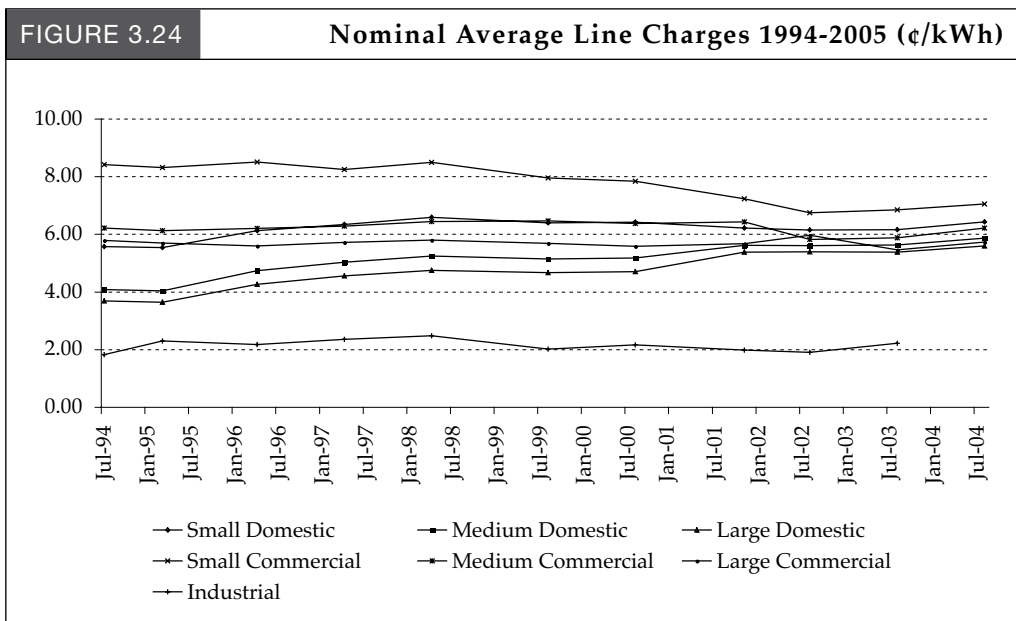
Nominal average line charges (including transmission charges but excluding GST) have followed varying paths for different consumer classes since the corporatisation of ESAs in 1994, but have converged somewhat more recently, as illustrated in Figure 3.24. The corresponding real average line charges by customer class are shown in Figure 3.25.

Nominal line charges have remained largely static for industrial and medium-to-large commercial users, implying decreases in real terms. Small domestic users have faced a slight increase in nominal line charges, but a small decrease in real terms. Medium and large domestic users have faced increasing charges in both real and nominal terms, while small commercial users have enjoyed significant nominal and real declines. The latter in part reflects the removal of cross-subsidies from commercial to domestic users.

<sup>11</sup> For example, The Power Company and Electricity Invercargill jointly own PowerNet Limited which, since 1994, has managed their respective lines networks, and which in September 2000 also assumed management of the network assets owned by Otago Power.

<i>Measure</i>	<i>Mean</i>	<i>Median</i>	<i>Minimum</i>	<i>Maximum</i>
Electricity Supplied (GWh)	997	368	40 Buller Electricity	9,774 Vector
Connections (ICPs)	66,107	26,136	4,171 Buller Electricity	644,000 Vector
Average consumption per ICP (kWh)	15,610	14,947	9,330 Electra	24,394 Electricity Ashburton
Interruptions	498	281	17 Nelson Electricity	3,198 Powerco
Faults per 100 circuit km	8.6	8.0	2.2 MainPower	17.3 Scanpower

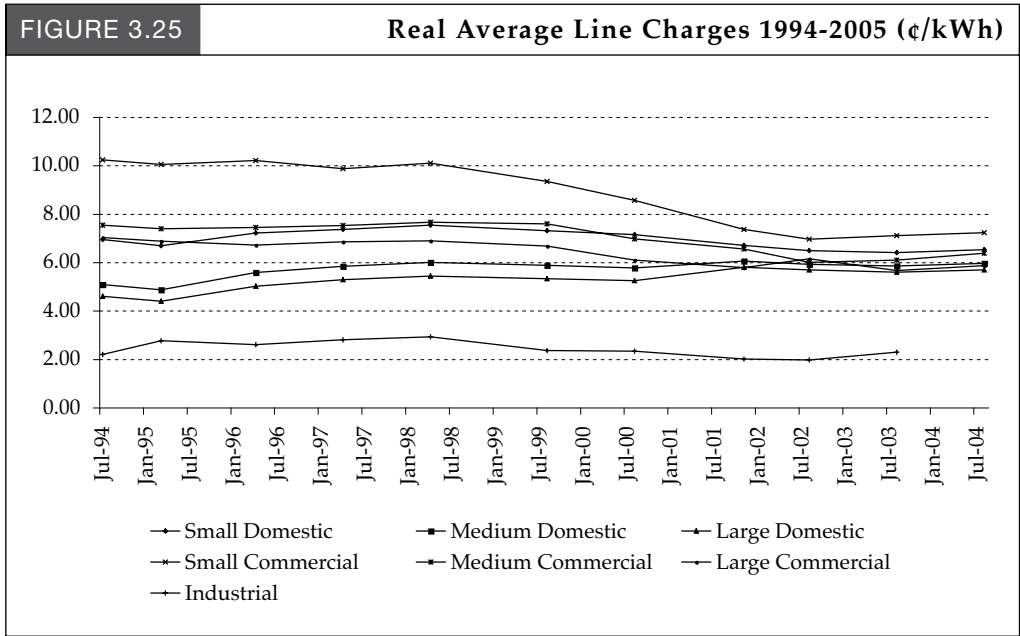
Source: PricewaterhouseCoopers (2005).



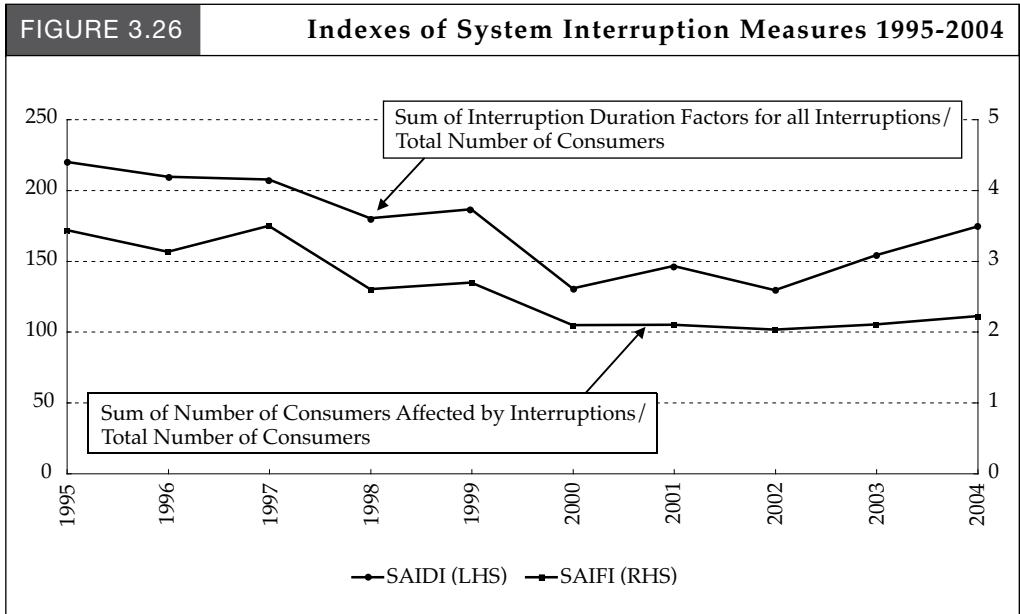
Source: Ministry of Economic Development (unpublished).

### Lines Quality

This period of reform has also seen significant improvements in service quality and productivity for the distribution sector. While these are often difficult to measure or to compare across service providers or over time, particularly because different networks have very different structural characteristics, there are some useful measures available. In these circumstances, price and productivity indices underestimate the rate of progress because they are not adjusted for improved quality.



Source: Ministry of Economic Development (unpublished).



Source: Annual information disclosures ([www.med.govt.nz](http://www.med.govt.nz)).

Note: Higher average interruption figures in 1999 include the 1998 Auckland CBD blackout.

Arguably the most important feature of service quality provided by distribution companies is service reliability. Two common measures of these are the System Average Interruption Duration (SAID), and the System Average Interruption Frequency (SAIF) measures. By converting these into indices per customer (SAIDI and SAIFI), we can analyse trends in system outages. As shown in Figure 3.26, both the average length and the average frequency of system interruptions have fallen rapidly over 1995-2004, during a period of rapid mergers and acquisitions of distribution companies, and have remained stable thereafter.

Productivity gains are an important source of potential efficiency gains. Meyrick Associates (2003) construct a measure of Total Factor Productivity (TFP) for lines companies over 1996-2003 using three output measures (energy delivered, system line capacity and number of connections) and five input measures (operating costs, and overhead, underground, transformer, and other capital items). After making some adjustments for the 1998 Auckland CBD lines failure (see Chapter 6) they find that productivity rises steadily over the period (other than a dip in 1997), increasing 3% between 1996-1999, 5.6% in 2000, and then a further 2.5% from 2001 to 2003, for an average annual productivity rise of 2%. Much of this change has come from a reduction in operating costs, with operating expenditure productivity having risen 33% over the period, while productivity of underground capital fell 10% and productivity of other capital types rose roughly 5%.<sup>12</sup>

## ENERGY RETAILING

Always a contestable component in the reformed electricity sector, energy retailing has also experienced the most dramatic changes in fortune. While the corporatised ESAs originally combined distribution and retailing, the formation of power-buying groups in the days of monopoly generation was quickly seen as a way to secure buying economies that could be translated into finer energy trading margins and a means to compete across traditional franchise areas. For example, Pacific Energy was formed by a number of distribution companies with the intention of developing its own generation capacity to compete with the then monopoly generator ECNZ, i.e. to be a vertically-integrated generator/retailer; and Energy Brokers was to be a buying group on behalf of major commercial and industrial customers, as was Power Buy on behalf of its members. A number of the larger combined distributor/retailers also acted as independent energy traders. Even before the vertical integration of generation and retailing that occurred following the final separation of ECNZ into competing generators in 1999, Boshier and

<sup>12</sup> Bertram and Twaddle (2003) also find that lines company operating costs have fallen significantly over the reform period, with average operating costs falling around 0.5 – 1.2¢/kWh over 1991-2002. They also argue that increases in lines charges reflect rising margins and abuse of market power. Their analysis of price-cost margins considers only average per-unit operating costs, explicitly excluding capital costs, but provides support for the argument that margins have risen.

Gordon (1996) noted the negligible margins being enjoyed by these energy-buying groups and traders. They argued that the long-term prospects for small energy traders were not encouraging (since size was required to compensate for low margins), and warned against the risks to traders of poor buying and selling decisions (e.g. buying electricity at the risky spot price and on-selling it under long-term fixed-price contracts).

Since energy retailers effectively repackaging the risk profile of their energy supplies, in many ways they can be thought of as being akin to banks.<sup>13</sup> Sourcing energy from their own generation, wholesale market purchases or supply contracts from other generators, they then on-sell that energy under pricing plans tailored to suit the price volatility/supply security preferences of their customers, or back to the wholesale market, power exchanges, etc.<sup>14</sup> They can also seek to acquire financial contracts, such as contracts for differences, that allow them to hedge their exposure to wholesale electricity price movements.<sup>15</sup> The retailing experience in New Zealand of Natural Gas Corporation during the 2001 winter power crisis, and that of its Californian counterparts in their 2000 crisis – as discussed in Chapters 4 and 5 – highlight the severe consequences of a retailer having unhedged electricity spot-price exposure on its wholesale purchases when retailing electricity at essentially fixed prices.

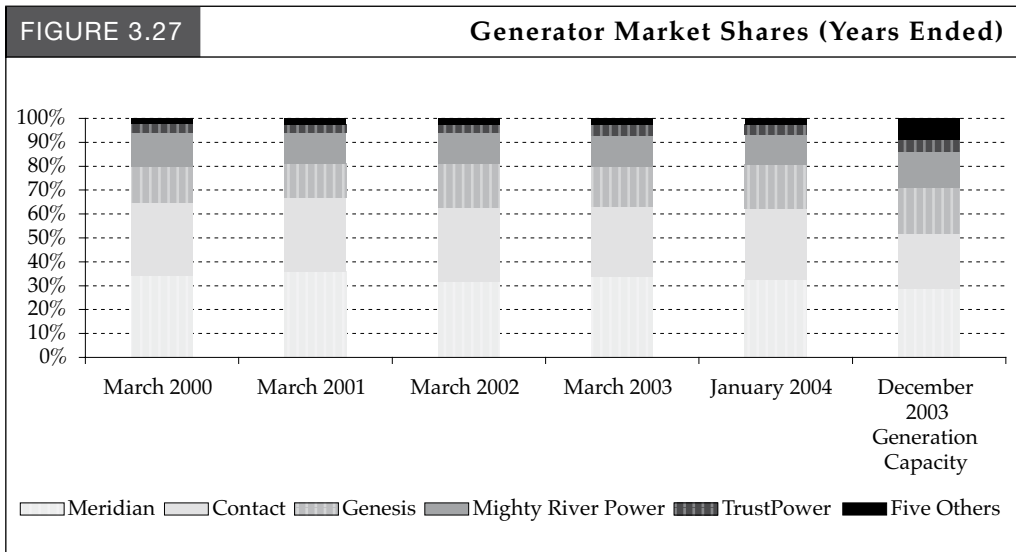
The forced ownership separation of lines operations from generation and retailing coincided with the ultimate break-up of ECNZ into competing generators. These generators had a natural inclination for vertical integration with retailing, the occurrence of which quickly undermined early retailing strategies in the reformed New Zealand electricity sector. As shown in Figure 3.27 and Table 3.5, retailing is now the preserve of organisations with a significant level of generation capacity relative to their customer demand – so-called “gentailers”. This reduces their exposure to the supply-price risk of wholesale market purchases, and reflects the fact that the current industry structure would otherwise require them to source energy from competing vertically integrated generator/retailers who themselves have little uncommitted generation capacity.

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<sup>13</sup> Traditionally, banks source funds from their shareholders, the wholesale money markets and retail depositors, repackaging the repayment and maturity characteristics of those funds into the fixed/floating interest rate and short-term/long-term maturity preferences of their borrowers.

<sup>14</sup> As discussed in Meade (2001), electricity prices tend to rise precisely in the same circumstances that volumes rise, causing generator profits to rise at an increasing rate, and retailer profits to fall at an increasing rate. In other words, supply shortages and price spikes are good news to generators, but bad news to retailers. Vertical integration provides a natural and arguably the most efficient hedge against these risks.

<sup>15</sup> Contracts for differences require one party to pay the other some amount determined on a contracted supply amount and the difference between the contract price and a reference price such as the current wholesale market price at a particular node. As such they are not unlike fixed for floating swap contracts commonly observed in the financial markets. For one vertically integrated generator to offer such a contract to another would require one of them to have a relative preference for fixed electricity prices over exposure to the wholesale market price. This in turn would reflect a complex combination of factors such as any imbalance between its available supply from own generation and other contracts and its customer commitments (or the price risk and maturity profiles of each), or its appetite to engage in “playing the market”.



Source: www.nzelectricity.co.nz, TPIX generation data.

**TABLE 3.5** **Retailer/Generator Market Shares as at January 2003**

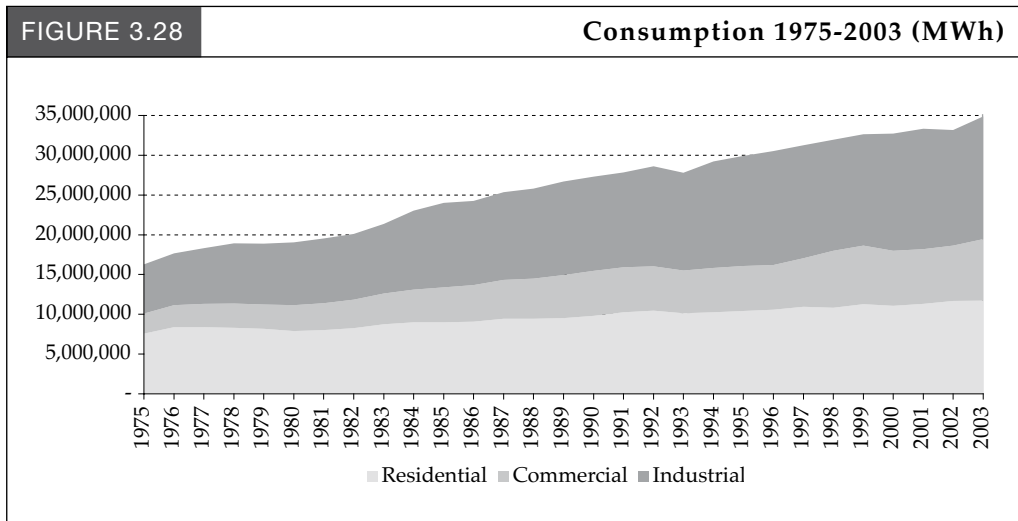
<i>Owner</i>	<i>Customer Numbers</i>	<i>Generation Capacity</i>	<i>Demand Share</i>	<i>Net Generation</i>
Meridian	12%	29%	33%	-4%
Contact	33%	23%	30%	-7%
Genesis	24%	19%	18%	+1%
Mighty River Power	16%	15%	13%	+2%
TrustPower	12%	5%	4%	+1%
Five Others	3%	9%	3%	+6%

Source: NZEM (2004), TPIX generation data.

The Electricity and Gas Industries Bill, enacted in October 2004, empowers the Electricity Commission to regulate for minimum levels of supply and other hedge contract to be offered by generators. It is thus now possible that the current gentailers will find themselves over-committed (i.e. via existing customer contracts as well as any new supply or other hedge contracts). In turn this might cause them to reduce their existing customer bases. The Commission is also empowered to regulate for minimum levels of hedge cover to be adopted by wholesale electricity purchasers. Taken together these have the potential, however artificially, to create a business case for non-vertically integrated electricity retailing. To the extent it does, however, then an additional business risk such operators would face – i.e. over and above that of mis-balancing the risk characteristics of their purchase and sale decisions – would be that of future regulatory change exposing them to the same fate as their predecessors.

CONSUMPTION

Over the past three decades total annual electricity demand in New Zealand has grown from 16,272 GWh to 34,890 GWh.<sup>16</sup> The strongest growth has occurred in the commercial sector, with an average annual growth of 3.9%, followed closely by industrial growth averaging 3.2%, and residential growth of 1.5%. In 2003 industrial demand accounted for 44% of electricity supplied (a third of that by NZAS), with residential demand accounting for 34% and commercial 22%. In terms of customer numbers the residential sector makes up 86%, with commercial 8% and industrial 6%.



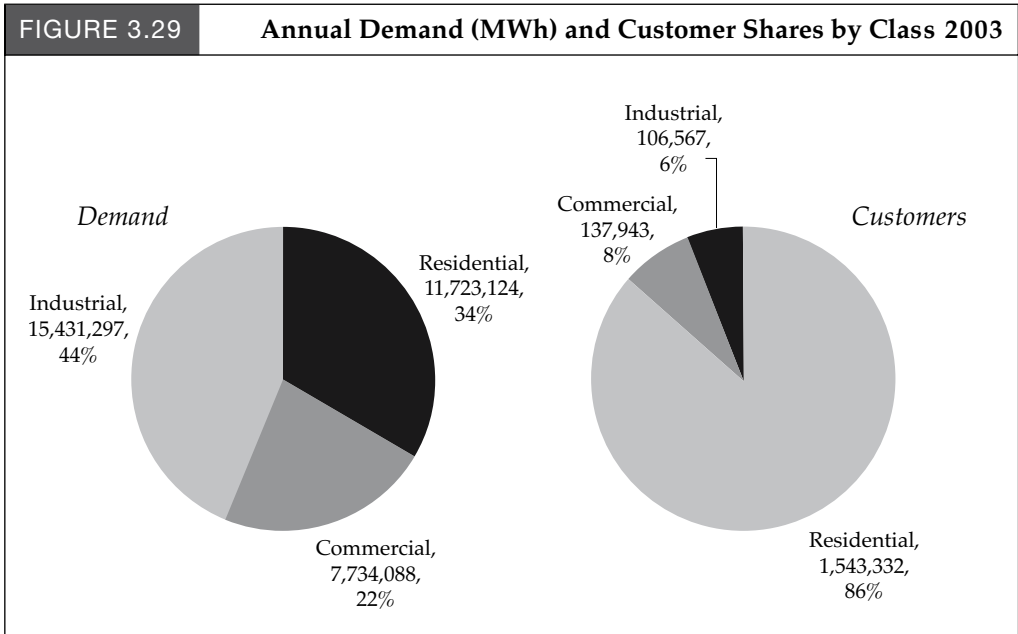
Source: Ministry of Economic Development (2004).

In terms of average annual consumption per customer it is the commercial sector that has experienced the strongest growth, with an annual growth rate averaging 3.7% over 1975-2003. By contrast, industrial sector growth has averaged 2.3%, with residential demand growth averaging less than 0.1%. As should be expected, average annual demand is highest for industrial customers (145 MWh/annum in 2003), followed by commercial (56 MWh), with residential a distant last (8 MWh).

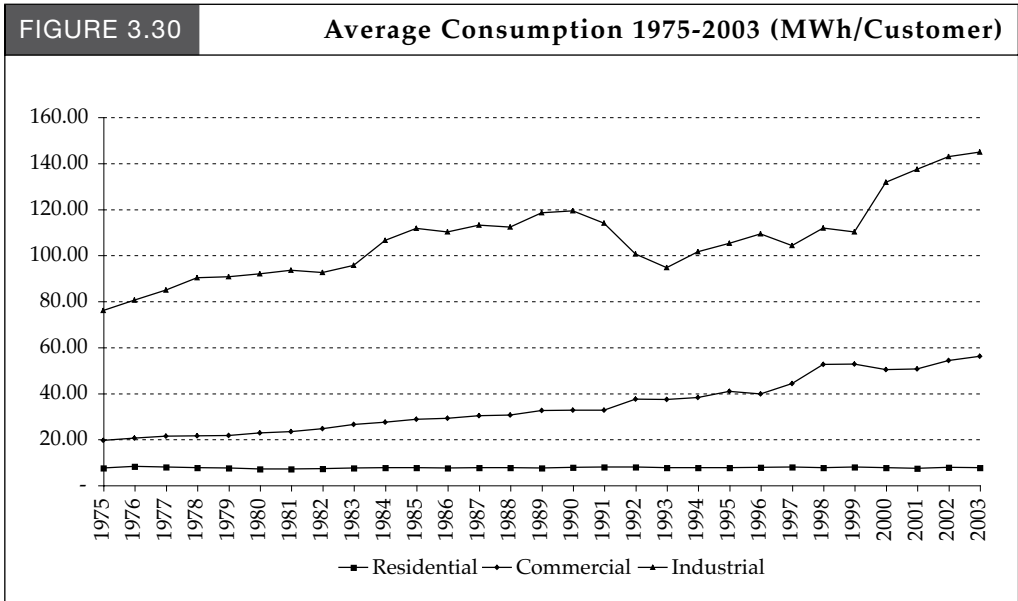
Figure 3.31 shows that nominal final electricity prices (covering energy, distribution and transmission charges) have followed significantly differing paths for each sector over the past three decades. Average industrial prices have remained consistently the lowest, but commercial prices have been significantly rebalanced relative to residential. With commercial prices traditionally attracting a premium relative to residential prices

<sup>16</sup> Which is less than the 39,594 GWh generated in 2003 largely because of transmission and distribution losses (averaging around 5% and 4% respectively), and the omission of own/co-generation from generation data (around 1,600 GWh).

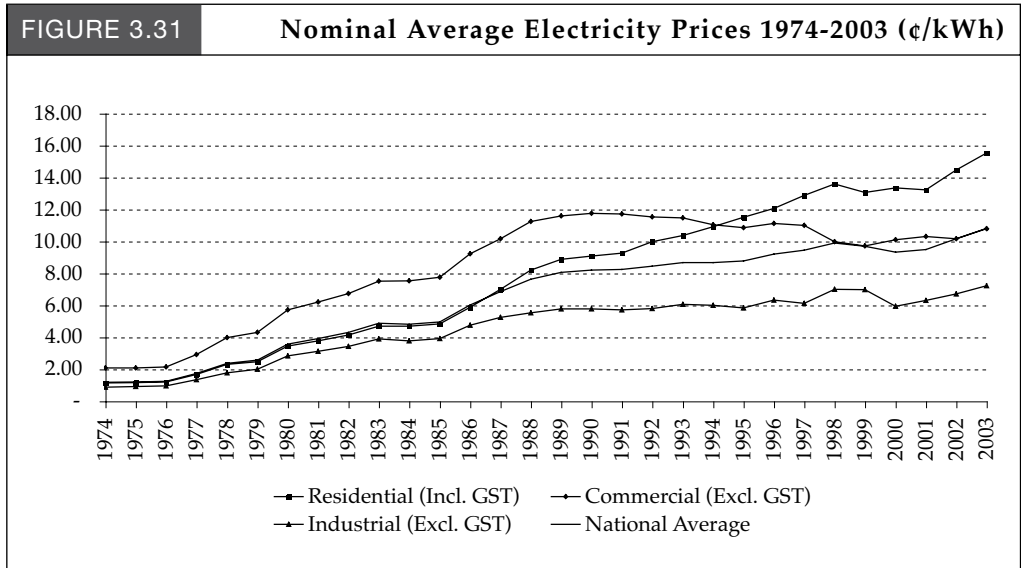




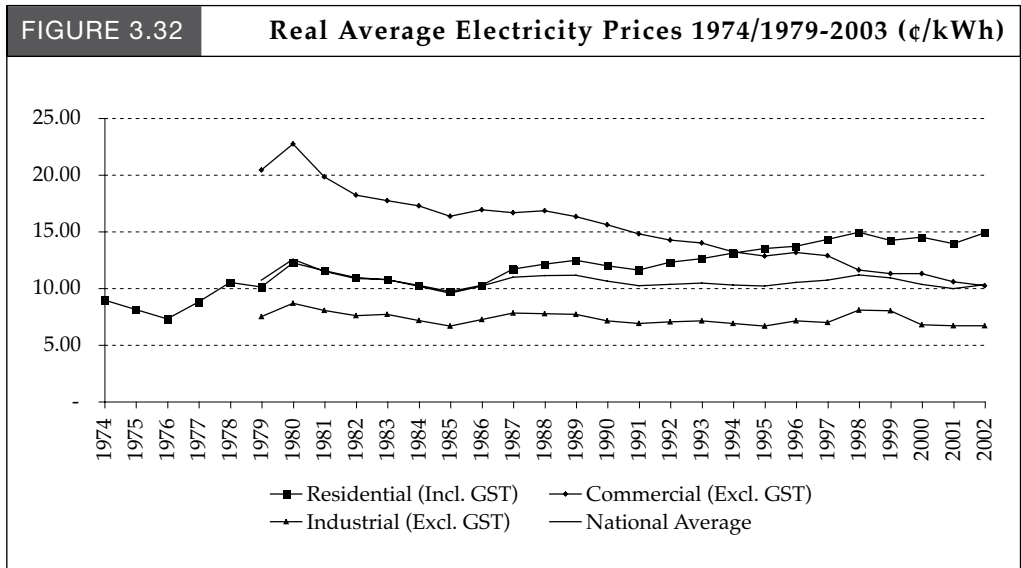
Source: Ministry of Economic Development (2004).



Source: Ministry of Economic Development (2004).



Source: Ministry of Economic Development (2004).



Source: Ministry of Economic Development (2003).

prior to the contemporary reforms, the corporatisation of distribution companies resulted in the removal of cross-subsidies from commercial prices which, combined with retailer competition for larger customers following the removal of franchise areas, explains both the reduction in commercial prices and some part of the increase in residential prices. Residential price growth also reflects the introduction of a 10% GST in the 1988 March year (subsequently raised to 12.5%), adding 5.4% to price rises that year. In terms of average growth rates, industrial prices have grown at the same rate as the national average price (8% p.a.), with commercial and residential prices growing at average annual rates of 9% and 6% respectively.

Real average prices echo these relativities, despite the use of differing deflators (producer price index for industrial and commercial; consumer price index for residential). Residential prices have grown at a real average annual rate of 2%, while commercial and industrial prices have fallen in real terms at average annual rates of 3% and 1%.

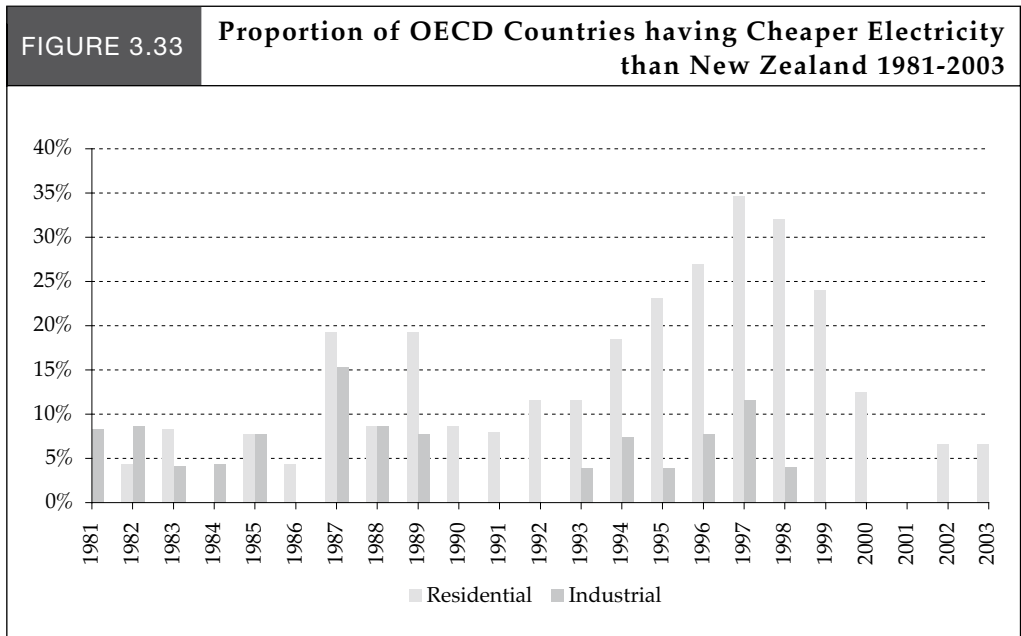
Relative to other OECD countries (25 on average for 1981-2001; 15 for 2002 and 2003), New Zealand has typically enjoyed cheap residential and industrial electricity prices. Figure 3.33 shows this advantage declined for residential users over 1994-1997, with an increasing proportion of OECD countries having cheaper electricity than New Zealand, but improved noticeably thereafter. This period of worsening relativity coincided with the corporatisation and restructuring of ESAs, as well as a significant rebalancing between commercial and residential prices. The industrial sector, by contrast, has enjoyed relatively low electricity prices throughout the two decades of comparisons. Notably these relativities have not apparently worsened with the introduction of the wholesale electricity market in October 1996; nor from 1987, with the sector moved to a profit-motivated commercial footing and funded on stand-alone commercial terms without state subsidy.

## FINANCIAL RETURNS

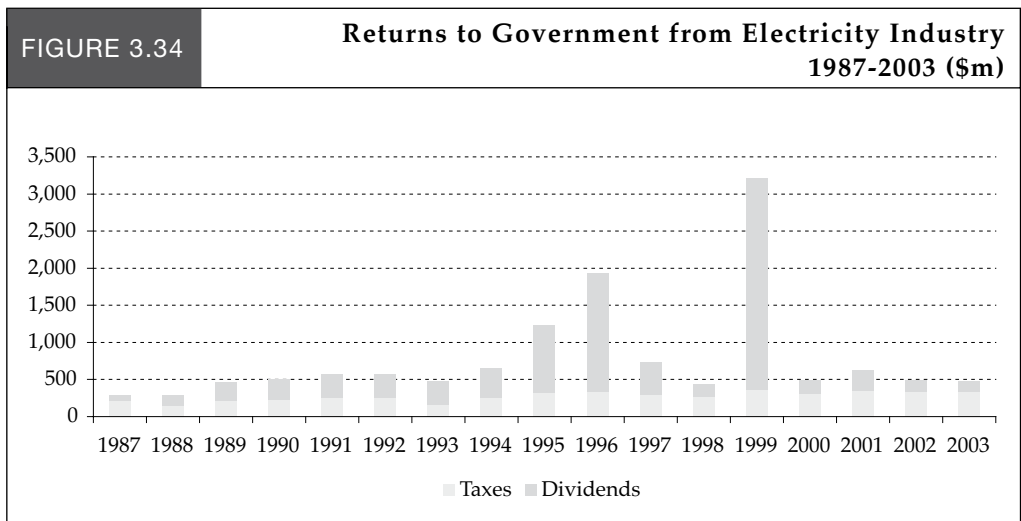
### *Returns to Government and the Taxpayer*

As shown in Figure 3.34, with the electricity sector finally paying taxes and government-owned generation and transmission finally paying dividends as a consequence of the reforms, the government has netted more than \$4.5 billion in taxes over the past 17 years (more in real terms), and dividends nearing \$9 billion.<sup>17</sup>

<sup>17</sup> For this figure and the three following it is noted that all returns are for the year to 30 June (requiring allocation of some companies' figures across years where balance dates differ). The compilations are mostly exhaustive, but exclude returns for companies which do not separate their electricity operations' returns from those of substantial other operations (notably Natural Gas Corporation). We have endeavoured to isolate electricity returns where possible, and only for New Zealand operations, but it has not been possible to do so consistently where companies operate in other sectors or countries (e.g. Contact Energy). Given the differing data sources, official and unofficial, from the various stages of industry reform required to produce a long-term returns series for so many organisations, these analyses should be regarded as indicative only. Sources and notes on the methodology adopted are provided in Appendix 3.2.



Source: IEA (various years).



Source: See Appendix 3.2.

Note: The large dividends in 1996 and 1999 arose as a consequence of capital repayments when Contact, and Meridian, Genesis and Mighty River Power, were respectively carved out of ECNZ.

Clearly the benefit of such returns will have been experienced unevenly among taxpayers, and with exceedingly little correlation to their electricity consumption. Hence while these returns should represent some contribution to aggregate welfare, they should also be expected to vary highly in their impact.<sup>18</sup> Notably, they have arisen while significant investment in new generation has taken place without direct recourse to the public purse, instead being funded on commercial terms by state- and privately-owned generators.

While the electricity sector paid no taxes and returned no dividends prior to 1987, other means were used to return cash to government. In 1980 the Electricity Division had leverage of 89% (which fell to 65% by 1986), comprised almost entirely of loans from government. Thus, central government received returns from the electricity sector through interest repayments (albeit possibly not at market interest rates). From 1987 ECNZ's leverage fell to around 50% where it has remained since (including its offspring generators), and its financing burden shifted from government towards private financial market borrowing. It is difficult to accurately calculate actual pre-reform net cash flows to government to compare with post-reform returns, as the picture is complicated by implicit cash transfers from taxpayers to the government-run predecessors of ECNZ, and because many construction costs for new generation plants were paid by the Ministry of Works rather than being borne by their effective owner.<sup>19</sup> However, the scale of post-reform SOE dividend and taxation payments, coupled with a general rise in SOE equity values, suggests the transition from departmental "cost-centres" towards SOE "profit-centres" has resulted in significant financial returns to taxpayers while real electricity prices have either risen only a little or in fact declined.

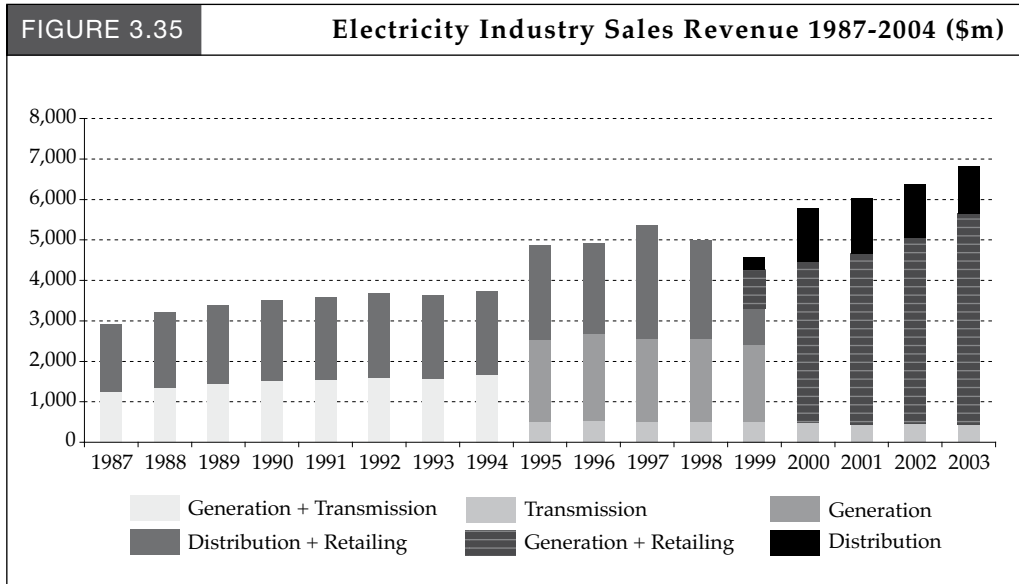
### *Financial Performance*

Figure 3.35 illustrates the financial performance of each sector in the industry over the course of the reforms, as reflected in sales revenue. While the various reconfigurations of the industry make sectoral comparisons difficult, it is not possible to discern any sector making gains in excess of those elsewhere, except perhaps generation for a time between 1995 and 1999 (and possibly beyond). Transmission in particular has suffered declining sales revenue, in the main because of a downward revaluation of its ODV in the year ending June 1998 – possibly reflecting an overvaluation of its assets (and hence increased returns) before then – and concomitant reduction in charges. It is possible that the aggregate revenue to distribution was lower in 1999 as a consequence of the 1998 reforms imposing ownership separation and other changes (such as removing electricity meters from ODV calculations) taking effect from that year, although the 1998 decline suggests some operating efficiencies may have been passed

<sup>18</sup> The actual effect on welfare depends upon the counterfactual and the extent to which any extra benefits contribute directly, and indirectly through taxation, to the real income of the populace.

<sup>19</sup> Ministry of Energy and ECNZ financial statements (various years).

on to customers. The increase in distribution and retailing returns in 1997, by contrast, may reflect early moves by lines operators to increase profitability towards levels permitted under the ODV regime (given historically low returns). In all cases it must be borne in mind that the volume of electricity generated, transmitted and distributed has grown throughout this period, which can explain increasing sales even where real unit prices have fallen.



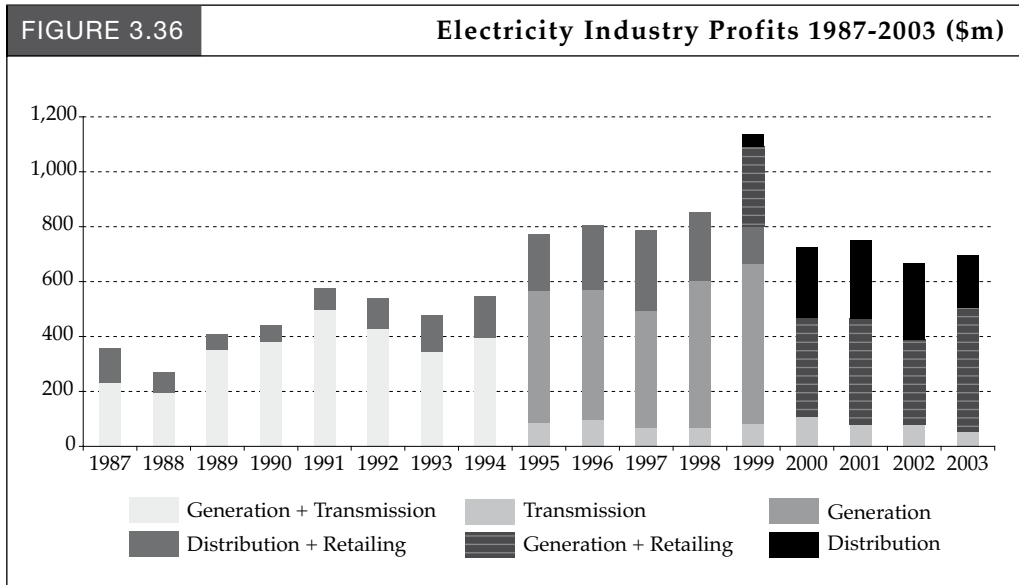
Source: See Appendix 3.2.

In terms of profitability, Figure 3.36 paints a more varied picture. Profits from distribution and retailing were patchy in the period preceding the sector’s reform in 1994, but stronger subsequent to reform, especially in 1997 (for reasons suggested above). The returns to generation appear cyclical with an increasing trend to 1999, but falling with the creation of Contact in 1996 and markedly lower following the final separation of ECNZ in April 1999. Interestingly no surge in generation profits can be observed for the financial years associated with the power crises in the winters of 1992 and 2001, despite dramatic increases in wholesale power prices and allegations of market power abuse and market gaming in 2001. This will reflect the hedge positions of generators at the time.<sup>20</sup>

Rising generator profits in earlier years will not only reflect growth in supply volumes, but may also be associated with the early productivity and other efficiency gains

<sup>20</sup> As mentioned in Chapter 2, hedges such as CFDs and fixed-price supply contracts have the effect of rendering the firm’s profits independent of the spot price for the quantity of electricity covered by the hedges. If a large proportion of electricity exchanged was under contracts that provided hedging, high spot prices will have only a small effect on the profitability of the supplying companies.

achieved in the early stages of ECNZ, and this while wholesale electricity prices were dramatically reduced in real terms (in anticipation of competition). Distribution profits have remained buoyant even following the separation of distribution and retailing in 1999, which as discussed earlier could be due to any number of reasons, desirable or otherwise. It is possible that their decline in 2003 reflects a defensive move by distributors in response to the Commerce Commission’s development of thresholds for implementing the new CPI-X regulatory regime on lines operations. The increasing profits to distribution and retailing over 1994-1997 coincide with the worsening of New Zealand’s retail electricity prices in comparison with other OECD countries, although its relative position was restored subsequently (including when generation integrated with retailing).



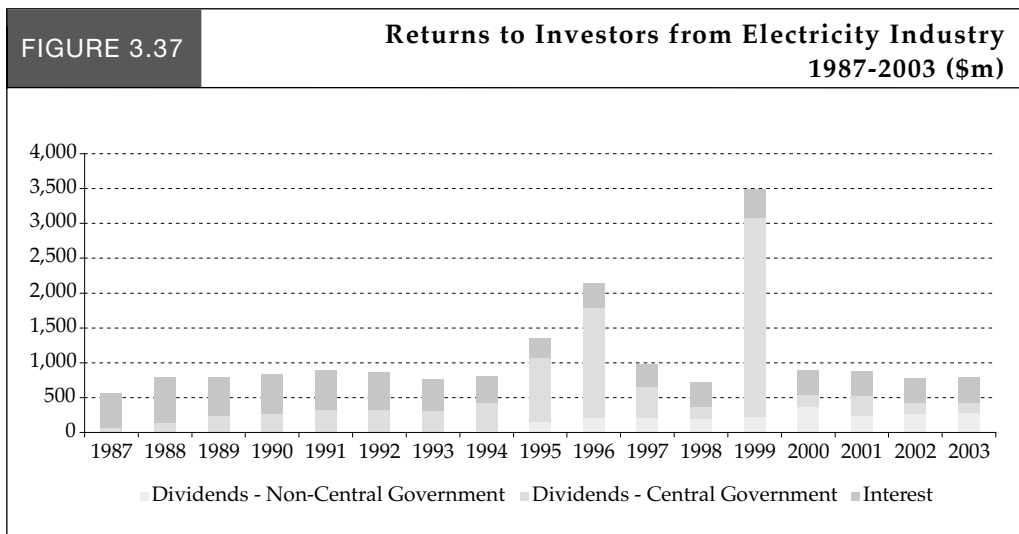
Source: See Appendix 3.2.

Note: Figures for 1999 will be confounded by the rapid transition of retailing from distributors to generators, and the final separation of ECNZ, both occurring that year.

As illustrated in Figure 3.37, once interest payments and dividends to non-central government are taken into account it remains the case that the taxpayer via central government has received significant financial returns from the electricity reforms. Communities, and in some cases electricity customers, have also enjoyed returns from locally owned distribution operations, albeit pre-reform returns were also enjoyed from this sector.

A final financial performance measure seeks to approximate the economic rate of return on electricity sector entities both pre- and post-reform. This measure looks at both the profits (or cash flows) to investors (shareholders and debt-holders) and the

capital gains or losses they enjoy as a proportion of the initial value of assets. Hutton (2004) attempts to construct such economic rates of return from publicly available accounting data in financial statements for the generation, transmission and retailing sectors from 1980 to 2002. Though there are a number of methodological problems and assumptions inherent in constructing this measure given a reliance on accounting data, such a measure represents the type of performance that an investor in the industry would more typically be concerned with, and so can be a useful indicator of financial performance. As illustrated in Figure 3.38, data suggest a slight decline in the real rate of return earned by investors over time, though some of this can be explained by a decline in real interest rates over the period. This measure excludes the distribution sector.



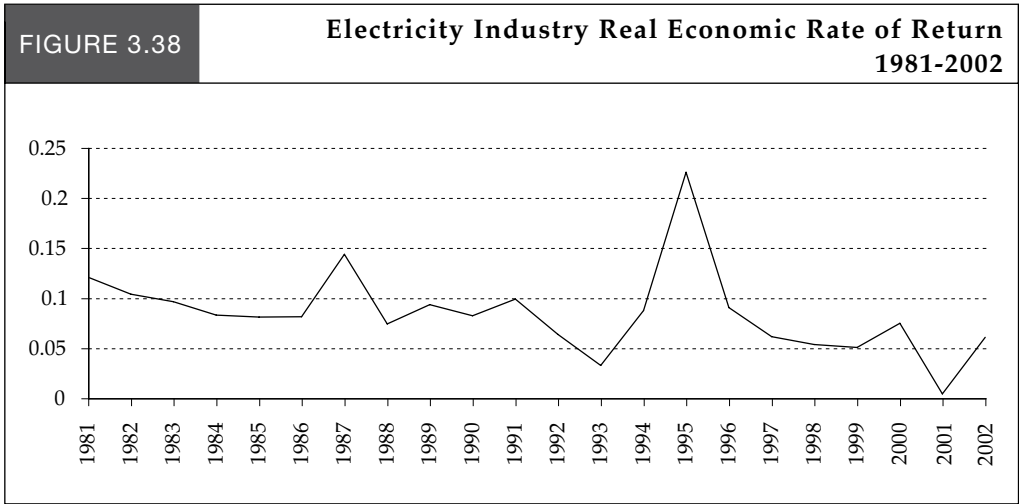
Source: See Appendix 3.2.

Note: The large dividends in 1996 and 1999 arose as a consequence of capital repayments to government when ECNZ was separated into Contact (1996), and Meridian, Genesis and Mighty River Power (1999).

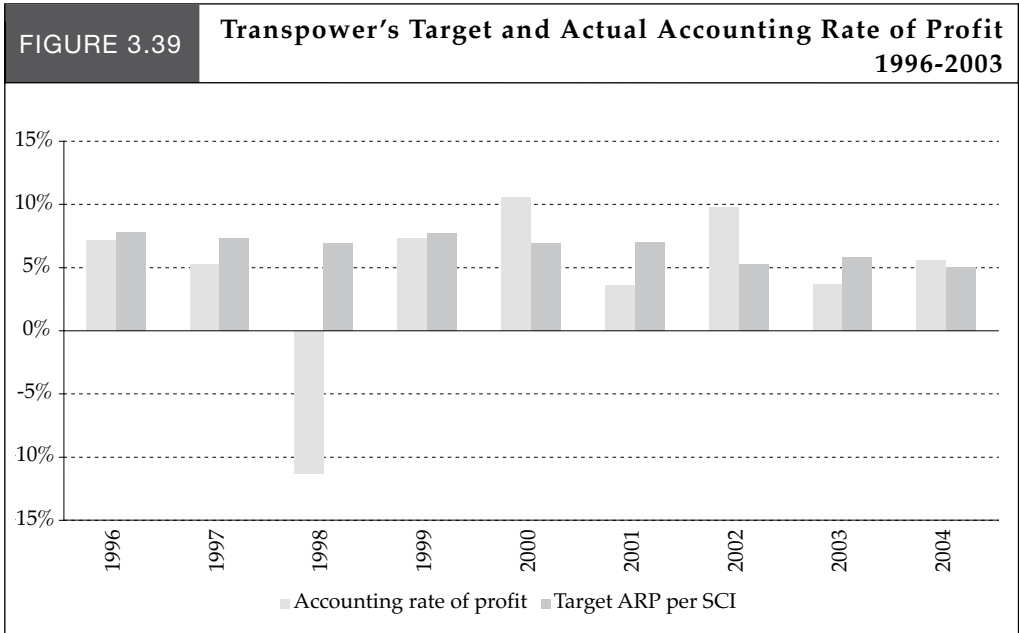
Figure 3.39 shows that Transpower has, on average, failed to earn an accounting rate of profit (more latterly measured as “return on investment”) equal to its target return as stated in its annual statement of corporate intent (SCI) required under the SOE Act. Its accounting rate of profit has averaged 4.5% p.a. for the 10 years to June 2004, whereas its target return has averaged 6.6% p.a. In part this perhaps reflects the risk of asset stranding and consequent inability of Transpower to recover its investment costs under the ODV methodology, let alone with price-caps now also being imposed.<sup>21</sup>

<sup>21</sup> Evans and Guthrie (2003) show that “optimising” inefficient assets out of a regulated firm’s rate base (i.e. as in ODV calculations) when setting allowable rates of return exposes that firm to demand risk warranting an allowable return in excess of that justified on traditional “systematic” risk grounds only (e.g. WACC). Accordingly, the fact that Transpower has, on average, earned less than even this narrower measure of allowable return is doubly telling.





Source: Hutton (2004).



Source: Transpower annual reports (various years).

## CONCLUSION

In structural terms the New Zealand electricity system looks much like that in other reformed countries or states, such as in England/Wales and Australia (particularly Victoria). Generation is no longer the preserve of a state-owned monopoly, although majority state ownership of generation persists. Transmission, like elsewhere, remains in the monopoly “too-hard basket”. Privatisation, unlike elsewhere, has become a politically precluded option. A centralised (and until recently voluntary and self-regulating) wholesale electricity market is now fully in operation, although decentralised trading through bilateral contracts ceased in March 2004 following the Electricity Commission’s advent. Distribution has undergone significant but arguably incomplete change, now being serviced by 40% fewer organisations than prior to the sector’s reform, and having been corporatised and mostly separated from competitive activities like retailing. Arguably, further rationalisation has been hampered by ownership and regulatory deficiencies (discussed further in Chapter 9), although alternative means of achieving efficiency gains have developed. Lines operators remain predominantly customer/community-owned, and while they had improved productivity and service under light regulation they now find themselves subject to CPI-X price regulation of the kind applied to investor-owned monopolies in other countries.

New Zealand is perhaps a little unusual in having allowed unfettered entry by generators into retailing following ECNZ’s final break-up in 1999, which has seen a significant rationalisation in the number of retailers and effectively required the vertical integration of generation and retailing for the latter to compete. This may change with the new Electricity Commission being given powers to regulate minimum levels of supply contracts and other hedge contracts for both generators and wholesale purchasers, which has the potential to cause a significant reconfiguration of the currently integrated gentailers.

Electricity consumers in New Zealand continue to enjoy cheaper electricity than their OECD counterparts, despite continuing demand growth, a shift towards profit-motivated and self-funding transmission and generation (now with some private ownership of the latter), price re-balancing, and a change in generation mix away from hydro generation towards gas-fired thermal plant with higher marginal operating costs. While indigenous energy sources have to date been sufficient to meet the demands of electricity generation in New Zealand, as proven gas reserves are depleted it is possible that future generation, and hence electricity prices, will be determined by indigenous coal and/or imported fuels such as LNG more than by hydro and gas reserves.

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**APPENDIX 3.1 – PERFORMANCE OF THE NATIONAL GRID 1990-2003<sup>22</sup>**

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**INTRODUCTION**

Load centres and electrical generators in New Zealand are interconnected by the electricity transmission system (the grid). The grid is the backbone of the national electricity infrastructure that connects local electricity lines companies and other parties (generators and some large load demanders). It provides services to all classes of consumers in New Zealand. These services can be classified under the headings of “energy transport”, “security and quality” and “interconnection”.

The three services of the grid cannot all be simultaneously maximised, as some trade-off position is always necessary. For example, the energy transport capability of the grid could be doubled by running it to its (thermal) limit, with no additional investment, but only at the expense of many more interruptions of supply to consumers, or increased risk of complete national black-out.

Increasing demand for energy transport could be achieved on the existing grid, but at the expense of an unquantified increase in the risk of black-out, or supply interruptions around the grid. This situation is undesirable, since the considerable costs of loss of supply are almost certainly divorced from those enjoying the benefits of increased transport. An important advance in the last decade has been to make the “trade-off” position explicit, and to price the variable costs of energy transport in a way that does not erode the provision of other grid services. Viewed in this light, the wholesale nodal energy market is a critical element in the efficient pricing of transmission services.

These comments take the capacity of the grid as given. While it is possible to invest in grid performance expansions of various dimensions, electricity grids are expensive and it will not generally be economically feasible, even if it were technically feasible, to expand grid capabilities to eliminate these trade-offs. It will not, for example, be economically or socially worthwhile to expand the grid to the point where there is no possibility of congestion. Further, the optimal size and configuration of the grid must be considered in the light of the incentives it provides generators and the demand for investment in capacity, technology and location.

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<sup>22</sup> This appendix draws on materials produced by Bruce Smith (formerly of Transpower, now of the Electricity Commission); used with permission.

## ENERGY TRANSPORT

The grid in 2002 carried electrical energy over 17,145 km of circuits, mostly at the high voltages of 220kV and 110kV. These electrical circuits are laid through approximately 12,000 km of transmission “corridors” over privately and publicly owned land. Transpower has relationships with 45,000 landowners, 69 District or City Councils, 12 Regional Councils, and four Unitary Authorities (i.e. Local and Regional Councils combined). Electrical energy is switched, and transformed at 186 substations. In terms of asset values, approximately 37% is in the substation assets, 35% in transmission lines (the towers, foundations, conducting cables strung between towers, and high-voltage insulators), and 19% in the high voltage link between the North and South Islands.

Only 2% of transmission corridors are through easements over property. Access over property to maintain lines is granted via the Electricity Amendment Act 2001. If easements were to be purchased over the remaining transmission corridors, it is estimated the capital value of some lines would increase by as much as 50%, substantially increasing the fixed costs of transmission.

Transpower’s capital stock as measured by Optimised Deprival Valuation (ODV) currently stands at \$2,151 million, a substantial decrease from the approximately \$2,870 million ODV in 1994 when Transpower was separated from ECNZ. Over that same period transmission charges have decreased in real terms by approximately 30%. Transmission charges are recovered through allocation of fixed costs to connected parties based upon anytime maximum demand. This particular allocation method is chosen as it most effectively approximates charging a fixed price for fixed costs since the grid must have the capacity to meet the maximum demand it transports.

In the last ten years, peak electricity demand has increased from 5.30 GW<sup>23</sup> to 6.07 GW (an increase of 15%) whilst annual electrical energy generation has increased from 32.03 TWh to 35.70 TWh (an increase of 11%). It is the increase in peak electricity demand that is most relevant to transmission. The size and cost of transmission assets is almost entirely dependent on peak demand, and independent of energy transported (the variable costs of transmission, related to energy, are discussed below).

The increase in peak demand has not been met by an increase in grid capacity, apart from those assets (capacities) which are attributable to single or small groups of parties connected to a particular part of the grid. An example of this is total transformer capacity (voltage-change equipment that is generally attributable to particular connected parties), which has increased by approximately 18% since 1993. Transmission lines, however, especially on the core-grid, remain virtually unchanged since 1993. The effect

<sup>23</sup> A GWh is a rate of energy consumption equal to one million units of electricity per hour. A TWh is a measure of energy equal to a thousand million units.

of this would have been to increase the capacity utilisation of transmission lines by the same percentage as peak demand has increased (i.e. 15%), were it not for the changed location of generation. The advent of the Taranaki (1996) and Otahuhu (2000) 450 MW gas-fired combined-cycle plants altered the amount and location of demand for transmission services.

The variable costs of transmission are the costs of losses, and the costs of transmission constraints. Transmission losses are the extra electrical energy which must be generated to overcome the electrical resistance of transmission lines and transformers. This energy is expended in unproductive heating of those assets. Losses increase quadratically with the capacity utilisation, and are highly dependent on the particular location of generation and load demanded in any half-hour period. Although losses are typically only 3% of generation, they are substantial in absolute terms, and may increase the price of electricity by 10% in some locations, at some times, in the grid.<sup>24</sup>

Transmission constraints occur when a transmission line or transformer is about to reach the security-constrained maximum energy transfer in a particular half-hour period, and higher-cost generators must be dispatched to meet demand. Unfortunately it is not possible to directly control the electrical flow in a transmission line or transformer (apart from stopping it entirely). Indirect control is achieved by changing the “generation dispatch”, i.e. the contribution of electrical energy from individual generators as ordered by the system operator. This indirect method of control imposes an additional generation cost, since the dispatch of generation is for a different objective than minimising cost of electrical energy generated.<sup>25</sup>

One of the “network benefits” of transmission is that the whole national conglomeration of generators and transmission assets is more reliable at every supply point than dedicated generation could be for the same price. If a single element of the system, either a generator or transmission, fails, the rest of the system has enough redundancy to cover that shortfall. This is referred to as “N-1” security.

For generators, “N-1” security implies that there is enough very fast response (spinning) reserve to cover the sudden loss of the largest single generator connected. The equivalent for transmission is that there is enough “thermal transmission reserve” – if any single transmission element fails, the remaining transmission elements can continue to carry the electrical energy for another 15 minutes before they overheat dangerously. During the 15-minute period the system operators must initiate some action to relieve the-soon-to-be overloaded transmission elements. If a transmission element is about to exceed this security-constrained limit, the only means of preventing this is to dispatch generation in a different pattern in the next trading period, at a higher price than otherwise.

<sup>24</sup> Prices in the wholesale market are set by marginal losses. In so doing the prices give the full short-run cost of an extra unit of electricity.

<sup>25</sup> The dispatcher’s schedule of generation ranks generation in order of cost, taking account of losses. But dispatched departures from this schedule are necessary in real time and these may raise costs.

Transmission constraints can have a dramatic effect on prices, reducing prices on one (the upstream) side of the constraint, and increasing prices on the other (downstream) side. If the constrained element is not much affected by generation, then more drastic changes in generation dispatch are required to control the loading on that element, leading to an amplified effect on nodal prices. This effect is technology related – if all transmission were always dispatchable the price impact of transmission constraints would be reduced.

Historically, transmission constraints have occurred either during periods of heavy grid loading (for particular generation patterns), or because transmission elements have been removed from service for maintenance, thus reducing grid capacity in particular areas – so-called “outage constraints”. Outage constraints tend to be sporadic and of short duration, whilst loading-related constraints are more dominant, but only occur in a few locations (e.g. central North Island, or the inter-island HVDC link).

It is only since 1998 that system operation has been performed to a precise “N-1” security level, so there is only a five-year record of transmission constraints. From July 1998 until December 2002 there were, in total, 20,722 transmission constraints (i.e. half-hour periods with one or more lines or transformers constrained). In 1999 there were 5,482 constraints, 7,805 in 2000, 4,520 in 2001, and 2,481 in 2002. The years 1999 and 2000 were dominated by constraints in the HVDC link, and central North Island transmission lines. After Contact’s new thermal plant at Otahuhu started generating, constraints dropped dramatically in 2001 and 2002 – illustrating the interrelationship among transmission constraints, location of generation investment and dispatch.

The impact of constraints on wholesale prices is a transfer of wealth between market participants. Retailers and generators will variously benefit and lose. Often the winner will also be the loser because of hedge arrangements including vertical integration between retailing and generation. Ideally, the short-term volatility of nodal price differences due to constraints should be hedged through tradable financial transmission rights (FTRs).

It is difficult to quantify the cost impact of transmission constraints. The cost to the industry manifests as a possible dispatch of higher-cost generation than would otherwise have been the case in the absence of those constraints, and in the enhanced potential for market power in affected locations. Further, the marginal cost of hydro generation, although better measured in the market, remains very difficult to measure.

An indication of the price impact (as opposed to producer costs) of losses and constraints are the transmission rentals derived from the nodal wholesale market. Rentals are a direct consequence of marginal cost pricing on a transmission system that has losses and/or constraints.<sup>26</sup> As the marginal costs exceed the average costs, the total

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<sup>26</sup> Loss rentals are depicted in Figure 3.18.

demand-side payments exceed the generator payments.<sup>27</sup> If losses and constraints were minimal, prices would be almost the same at all locations on the grid; rentals would be negligible. In the New Zealand grid, losses are important, and often constraints arise, and these are signalled by rentals on the New Zealand grid. The rental payments are not lost to the wider wholesale electricity system because they are passed through to parties connected to the grid.<sup>28</sup>

From October 1996 until December 2003, total rentals were \$581 million. Over that same period, total payments to generators were approximately \$12.9 billion, so the size of the transmission rentals “market” has been almost 5% of the wholesale electricity market (see Figure 3.18). On an annual basis, there is considerable variation in the rentals, both in absolute terms and as a percentage of the wholesale market.

Despite the fewer transmission constraints, in absolute terms rentals were highest in 2001 (because of the high spot prices during the winter “crisis”); but as a proportion of generator revenue they were low, suggesting that the southward flows of electricity in 2001 did not generate high marginal losses. In contrast, in 2000 electricity flows and grid configuration combined to produce unusually high losses relative to generation: there were periods during this year in which Otahuhu B could not run and this may have affected this result.

While the dollar rentals have increased since 1999, comparison of them with rentals as a percentage of generator payments show that the increase reflects the generally increasing wholesale price of electricity and not increased overall congestion of the grid. As mentioned, losses increase faster than energy transmission in the presence of congestion. Increased frequency of constraints would also generally increase real rental payments. The fact that, as a percentage of generator payments, rentals have not increased strongly suggests that the grid has not engendered increased losses and suffered critically more constraints throughout the period of the wholesale spot market. This reflects the relatively minor modifications to the grid and the (re)location of generation over the period.

## RELIABILITY AND SECURITY

The operation of the grid to “N-1” security prevents the possibility of cascade failure leading to black-out, and also minimises supply interruptions. Through the nodal wholesale market, the cost trade-off between this level of security and the variable

<sup>27</sup> Including payments for losses.

<sup>28</sup> The pass-through of rentals to grid-connected parties is carried out, in large part, to ensure that the grid owner, Transpower, does not benefit from them: were it to so benefit it would have an incentive to create grid congestion rather than ameliorate it. The effect of the transfer of loss and constraint rentals is to reduce the financial impact on grid-connected parties of their costs of connection to the grid.

costs of energy transport are accurately signalled. It would therefore be expected that, over time, security and reliability would remain constant, but that loss and constraint costs would increase. As discussed earlier, this increase in cost has not occurred because of the timing and placement of thermal generation.

System reliability has on the whole improved over the past ten years, on a number of measures. Load-weighted average system interruption times (in “system minutes”) have declined over 1991-2003, as has the total number of interruptions to Transpower customers over this period. It is worthwhile to note that on an annual basis there is a substantial variation in the measures of quality, so that any trend should be over a rolling “several year average”. Even single events such as weather or equipment failure can influence the aggregated quality figures for a single year. As an example, unusually high system minutes in 1992 and 1993, were caused by two bus faults, an HVDC trip, and snowstorms in Canterbury (which caused 12.2 system minutes alone). All these measures of grid performance have been trending downwards (see Figures 3.19 and 3.20).

## INTERCONNECTION

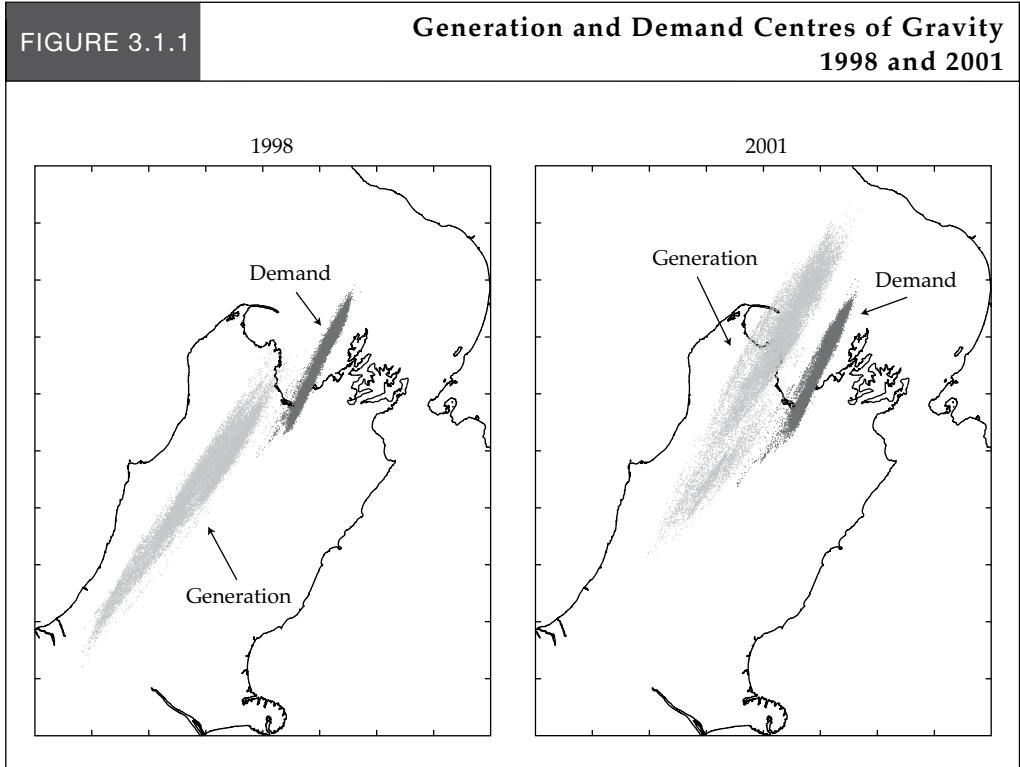
The benefit of interconnecting demand and generation at the national level is access to diversity of generation. In New Zealand, generation is mostly geographically distant hydro generation, geothermal, and more local thermal generation fuelled by either natural gas or coal. Hydro generation is subject to limited storage (approximately 7 weeks of generation) and dry years (in which generation can be reduced by 15%).

From year to year, demand for electricity is quite predictable with regard to location and size. Generation is much less predictable, as illustrated in Figure 3.1.1.

In these graphs the centre of gravity of generation and demand per half-hour are plotted for 1998 and 2001. In 1998 there was a heavy dispatch of hydro generation in the South Island, with the HVDC link transmitting energy to the North Island. During the 2001 dry year, there was a much greater dispatch of new and existing thermal generation, located in the North Island, shifting the centre of gravity of generation about 175 km further north. During 1998 the average distance that energy was transported was about 230 km as opposed to 135 km in 2001.

Prior to 1998 there are insufficient records of generation dispatch to calculate grid energy transport distances. It is likely that hydro generation was historically dispatched as base-load, with thermal peaking normally and running base-load in dry years. Today base-load can be met either by hydro or thermal generation, whether or not there is a dry year, and the generator on the margin can always be either thermal or hydro.





Source: Bruce Smith (presented at the Electricity Engineers' Association Conference, 2002).

When the dispatch of generation can be so diverse, the flow of energy in the grid is diverse as well. This means that more branches in the grid must be of higher capacity. On the whole, the New Zealand grid needs to be of higher capacity for the amount of energy transported, compared with other national grids of similar size. In the future, with greater emphasis on distributed generation and renewables such as wind and small hydro, the capacity utilisation is likely to decrease even more.

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**APPENDIX 3.2 – NOTES AND SOURCES FOR FIGURES 3.34-3.37**

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**GENERAL APPROACH**

All figures have been disaggregated as far as possible.

All figures have been annualised to June years.

*Sales* figures are before discounts, include those from discontinued operations, and exclude internal revenue or internal transfers. Interest revenue is included in 'other'. Meridian's gain of \$81m on the sale of the Cobb power station has been excluded.

*Net Profit After Tax* excludes extraordinary expenses or abnormal items, and is before any surplus/deficit from associates. Revaluations have been excluded, in particular, for Transpower.

*Tax Expense* is in some cases a tax credit. For the distribution companies prior to 1994, provision for tax is used. From the data it appears that the distribution companies started paying taxes in 1989.

*Dividends* includes those paid in shares, but excludes dividends paid to other parts of the business. The lines-company data do not give any dividend figures prior to 1994.

*Interest Expense* is given for generation and transmission companies.

*Net Interest* is given for distribution companies. If the net interest figure could not be found, the interest expense figure was used instead. The interest expense figure is used prior to 1995.

Some of the distribution companies give their customers discounts instead of dividends. This forms another source of return to customers, but has been excluded from total returns.

Where data are missing for a period, e.g. because of a change in balance date, figures are allocated pro rata from those either side of the missing period in order to produce an annual figure. Also, because of an amalgamation, Powerco's 2001 financial year contains seven months; figures in this year have been annualised by multiplying by 12/7. For the distribution companies and Trustpower, figures for the year ended 30 June 2003 have been obtained by inflating the nine months' worth of data for this period, based on the 31 March 2003 figure.

The first six months of Trustpower figures (the period ending 30 June 1994) have been included with the distribution companies. Note that its activities included generation in this time.

From 2000 onwards ECNZ is being operated as a residual entity, winding up its outstanding hedges.

## DATA SOURCES

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*In this chapter we survey the context, history and consequences of reforms in a selection of overseas electricity systems. The intention is to provide international context to New Zealand's reforms, as summarised in Chapter 5. Combined with the snapshot of the New Zealand electricity system provided in Chapter 3, this provides solid benchmarks against which to assess New Zealand's progress and experience. As will be seen, New Zealand has managed to avoid some of the pitfalls experienced elsewhere. At the same time, however, it has been relatively timid in implementing its reforms compared to the US, England and Wales, Australia, and even the late-starting European Union.*

## INTRODUCTION

### *Broad Reform Trends*

Electricity sector reform since the 1980s, in the main involving some degree of tilt towards decentralised market-based and competition-oriented rather than government and centrally planned solutions, has for some time been the developed world's equivalent of fashion's "new black". Wherever electricity systems first developed, local and central governments quickly involved themselves in the process – whether at the policy, regulatory, ownership, or control levels. While competition was in some places also quick to develop (even in areas such as distribution where current thinking holds that it is uneconomic and that monopolistic tendencies need to be tamed), such competition has even been argued to have spawned regulation by those wishing to constrain competition rather than to protect consumers. With time, regulation and/or state ownership and control of the sector became the norm, and for decades appeared to adequately meet the twentieth century's ever-growing demand for electricity. As imperatives changed, however, so too did the received wisdom regarding how electricity systems ought or needed to be organised. Aided by technological innovations that facilitated solutions previously regarded as impossible, transformation was feasible as well as necessary.

### *Deregulation, Liberalisation or "Reregulation"?*

It is possible to discern not just a linear trend towards one approach over another, but "alternating currents" in the way electricity sectors around the world have evolved and been organised. Apart from the earliest days in which pioneering entrepreneurs dictated the agenda for electricity system development, some measure of controlling oversight has been exerted by central and local governments. This oversight persists to varying degrees even today, where the broad thrust of contemporary electricity sector reform has been characterised as "deregulatory". Such a characterisation is not wholly accurate,

however, as deregulation implies a removal of government involvement whereas the reality of contemporary reform is that of ongoing but changed involvement. An alternative description that might be applied is that of “reregulation”, by which governments change the rules of the game but do not entirely withdraw themselves from it. Where such reregulation entails a shift away from state control or central planning, it might better be termed liberalisation. And while liberalisation is often regarded as the modern way, where earlier liberalisation occurring under contemporary electricity sector reforms has been regarded as unsuccessful (or simply unpopular or too radical), subsequent reforms have sometimes been directed at “deliberalisation”. In this sense reregulation can also be thought of as retrograde, highlighting the fluid nature of the process.

### *Rise of “the Market”*

At the heart of such reforms has been a change in attitude towards the desirability of market forces and competition, and the ability of such forces to be applied in at least some parts of the electricity sector. Widespread dissatisfaction with the public-service model of electricity supply – given the considerable inefficiencies, price-discrepancies and cost that came to be associated with the sizeable investments required by the industry – spurred interest in the use of market forces that had already begun to be effectively applied in other sectors such as railroads, natural gas supply and telecommunications. At the same time improvements in information and communications technologies provided a means to decentralise control of generation, paving the way for monopoly generators to be split into separate units competing among themselves and with new small generators via centralised or decentralised wholesale electricity trading arrangements. While long-distance transmission and local distribution continued to be regarded as monopolies, a greater confidence emerged that regulatory measures could be effectively applied, and more properly targeted, to tame these beasts, paving the way for competitive energy trading at the retail level. In at least some part these changes in attitude reflected a realisation that certain of the monopoly concerns arising in the context of state-owned or -controlled electricity systems were in fact self-created and unnecessary.

## CONTEMPORARY ELECTRICITY REFORMS AROUND THE WORLD

Reform of the electricity system in England and Wales is widely regarded as being at the vanguard of contemporary reforms, with competition in generation and retailing under a centralised wholesale electricity market introduced in 1990. Indeed, independent power producers (IPPs, i.e. generators) were encouraged in England and Wales as early as 1983. Norway was not far behind, commencing widespread reforms in 1991 although it had operated a generator-only power pool as long ago as 1971. Argentina commenced the break-up of state-owned generation and transmission and established wholesale power trading arrangements from 1993, the same year that Victoria led the way in restructuring Australia’s state-electricity systems. Reform in the

United States also progressed on a state-by-state basis, with California being the early and unfortunate leader. The US also instituted wider policy changes supporting reform as far back as 1978, with legislation paving the way for non-utility generators (i.e. IPPs) to participate in the wholesale electricity market. Western Europe has in fact been a relative late-starter in the reform process, with major reform first being mandated under a 1996 European Union directive having antecedents dating to 1988.

These are but a few significant examples of countries or regions embarking upon a reform process, among which some have been particularly influential in shaping developments in subsequent reforming states (in both positive and negative senses). The reform processes in a selection of these are expanded on below to provide context and counterpoints to the later discussion and assessment of New Zealand's reforms.

## ENGLAND AND WALES

### *Wider Reform Agenda*

Unquestionably the reform of the England and Wales electricity system was a reflection of a wider reform agenda of the conservative government under Margaret Thatcher (elected in 1979). Aside from fiscal imperatives, the Conservatives had a clear vision of state-sector reform through market liberalisation and the privatisation of state trading enterprises, with the electricity sector being no exception. In so doing the Thatcher government radically unwound a relatively short-lived era of government domination of the sector.

### *Reform Background*

Central government authority over the electricity sector begun under the Central Electricity Board with 1926 legislation charging the Board with constructing a national transmission grid. It was not until after the Second World War, however, in 1947, that the electricity systems in England, Wales and southern Scotland were nationalised. Government authority over the sector was later extended, with the formation of the Central Electricity Generating Board (CEGB) in 1957 to control the operation of and investment in both generation and transmission. As in the United States, the oil price shocks of the 1970s resulted in a shift towards domestic over imported fuels (a shift assisted by the 1965 discovery of gas in the North Sea). Electricity prices in this period were subject to political pressure, for example in the 1970s to restrain prices to contain price inflation, and to raise prices in the 1980s to reduce public debt. The electricity sector was also used as a means to support the inefficient domestic coal industry, and to assist with the development of nuclear power. The Thatcher government attempted to encourage the entry of IPPs with legislation in 1983 allowing them access to the grid, but it was not until the Electricity Act of 1989 that widespread liberalisation and privatisation of the electricity system commenced.

### *Generation and Transmission*

Initially all generation and transmission in England and Wales was under the control of the CEGB. The 12 semi-autonomous area boards responsible for distribution and retailing had little effective control and thus the system was a vertically integrated state monopoly. Reform involved transmission being separated out into the National Grid Company (required to provide open access to all grid users and to dispatch generators), and initially all generation – split into two fossil fuel generators (PowerGen and National Power) and the nuclear generator (Nuclear Electric) – were to be privatised. Nuclear Electric was removed from the sale process because of concerns about the costs of reactor decommissioning, but its newer plants were privatised as British Energy in 1996, with only its older plants being retained by the government as British Electric. Accordingly only the two fossil fuel generators were sold early in the process, with 60% of their shares auctioned in 1991 and the balance in 1995. Changing political preference towards the domestic coal industry and deregulation of the gas industry eventually resulted in a flight to gas generation, and levies favouring nuclear power were phased out by 1998. To facilitate price competition between these three generators a compulsory centralised “pool” was established to set wholesale electricity prices, although much energy traded was hedged via bilateral contracts.

### *Distribution/Retailing and Regulation*

The 12 area boards responsible for distribution and retailing were corporatised into regional electricity companies (RECs) and auctioned off in 1990. The RECs initially owned transmission, but were required to sell down their holdings in 1995 because of competition concerns, with National Grid Company becoming publicly listed and changing its name to National Energy. A new regulator, The Office of Energy Regulation (OFFER), was created to regulate the industry and it imposed price caps on transmission, distribution and, for customers still subject to franchise areas, energy retailing. Service standards were also imposed and repeatedly revised to ensure quality was not compromised to improve profits under regulated prices. The RECs were required to ring-fence distribution from retailing, with both regulated under a CPI-X regime but with the latter to be successively deregulated. Franchise areas were opened up to retail competition: first for customers having peak demands of more than 1 MW in 1990, allowing such larger customers to purchase electricity at unregulated prices; and then for successively smaller customer classes in 1994 (those with peak demands exceeding 100 kW), with franchise restrictions finally lifted for the smallest customers from September 1998 through to June 1999. RECs were also constrained in their ability to acquire generation, so as to encourage competition among generators.

### *Re-Reform*

These radical transformations of the England and Wales systems were not to last in their initial state for long. Dissatisfaction was quickly expressed with the lack of competition



among the three generators and “gaming” of the wholesale pool, resulting in OFFER implementing a short-lived cap on wholesale prices in 1994, and the replacement of the pool in 2001 with decentralised, self-dispatched generation and a much smaller balancing market designed to encourage generators to avoid imbalances in supply and demand (New Electricity Trading Arrangements, NETA). Initial policy goals of enhancing economic efficiency in the sector were eventually broadened to include equity and environmental aims. While falling fuel prices resulted in increased generator profits over the first five years of the reformed sector’s operation, consumers saw little benefit in the form of reduced prices, prompting the regulatory imposition of considerable and repeated price cuts on retailers and on transmission.<sup>1</sup> As early as 1993 OFFER sought to encourage greater competition in generation by agreeing with PowerGen and National Power that they sell down capacity, in exchange for the resulting smaller generators being then permitted to vertically integrate with RECs. The result of this multi-faceted and multi-staged process is a vastly transformed industry, with foreign ownership of generation and RECs the rule, multiple competing generators (including IPPs providing new generation capacity), and lower electricity prices by decree if not market forces. Inefficiencies arising from the influence of the domestic coal and nuclear industries have been ameliorated, if not eliminated, and along the way the British taxpayer has enjoyed considerable proceeds from asset sales.

## UNITED STATES

### *Anti-competitive Regulation Origins*

The US electricity industry began, with Thomas Edison’s first Manhattan power plant in 1882, as unregulated private enterprise. As Stoff (2002) puts it, “[i]n the beginning there was competition – brutal and inefficient”. Early experience in the United States saw instances of intense competition for both electricity generation and distribution, a matter resolved in Chicago by the then president of the National Electric Light Association, Samuel Insull, who acquired a monopoly over central generation in the city in 1898. More as an attempt to secure his position against competition than to protect consumers, Insull made the case for regulated “natural monopolies” arguing that “exclusive franchises should be coupled with the conditions of public control, requiring all charges for services fixed by public bodies to be based on cost plus a reasonable profit”. These ideas found early acceptance, with New York

<sup>1</sup> Following privatisation of the 12 England and Wales distribution companies in 1990, X-factors ranged between 0 and 2.5%, subject to review in 1994. Evidence discussed by MacKerron in Glachant and Finon (2003) suggested that these were too lax, resulting in increased prices and profits. Indeed, Wolfram (1998) provides evidence that large salary increases observed for distribution companies post-privatisation were not associated with more usual predictors such as managerial talent or firm size, but were highly correlated with the companies’ potential profits, as measured by their X-factors. In 1995 the distribution companies were subject to more stringent price controls, with price cuts of 11–17% in 1995, a further 10–13% in 1996, and 3% annually for three years thereafter. Overall distribution company revenue was cut by 27% from 1990 to 2000. Initially required to cut prices by 3% annually from 1993, the National Grid Company faced a 20% price cut in 1997 and 4% annually thereafter.

and Wisconsin establishing state utility commissions in 1907,<sup>2</sup> and 1935 federal legislation set about to break up interstate pyramid-company holdings of electricity providers into geographically contained units. Thus the twentieth-century US model of rate-of-return regulated, intra-state, franchise-based, vertically integrated electricity providers was born.

### *Dominance of Investor-Owned Utilities*

Eventually the US electricity system came to comprise multiple semi-autonomous but interconnected sub-systems, divided for bulk power trading into three major interconnection networks (combined with portions of Canada and Northern Mexico): eastern, western and Texas. By the end of 1996 there were 3,195 electric utilities throughout the country, around 700 of which were generators and most of which were combined distributors/retailers. Many utilities served franchise areas within single counties, but sometimes a county might be served by more than one utility (or utilities may service more than one county). The high-voltage transmission network, divided into around 150 control areas, was owned and operated by larger utilities to allow them to trade electricity, with around half of all electricity generated being traded through wholesale trading arrangements. Of particular note in the US context is the dominance of investor-owned utilities (companies generating power for public use), with around three quarters owned by private investors, 20% federally or otherwise publicly owned, and 5% owned by cooperatives. Non-utility generators (privately owned generators supplying themselves, utilities or others) have also taken an increasing share of generation (12% by 1996) under various early national reform initiatives, further diluting municipal, state and federal ownership in the sector.

### *Reform Imperatives*

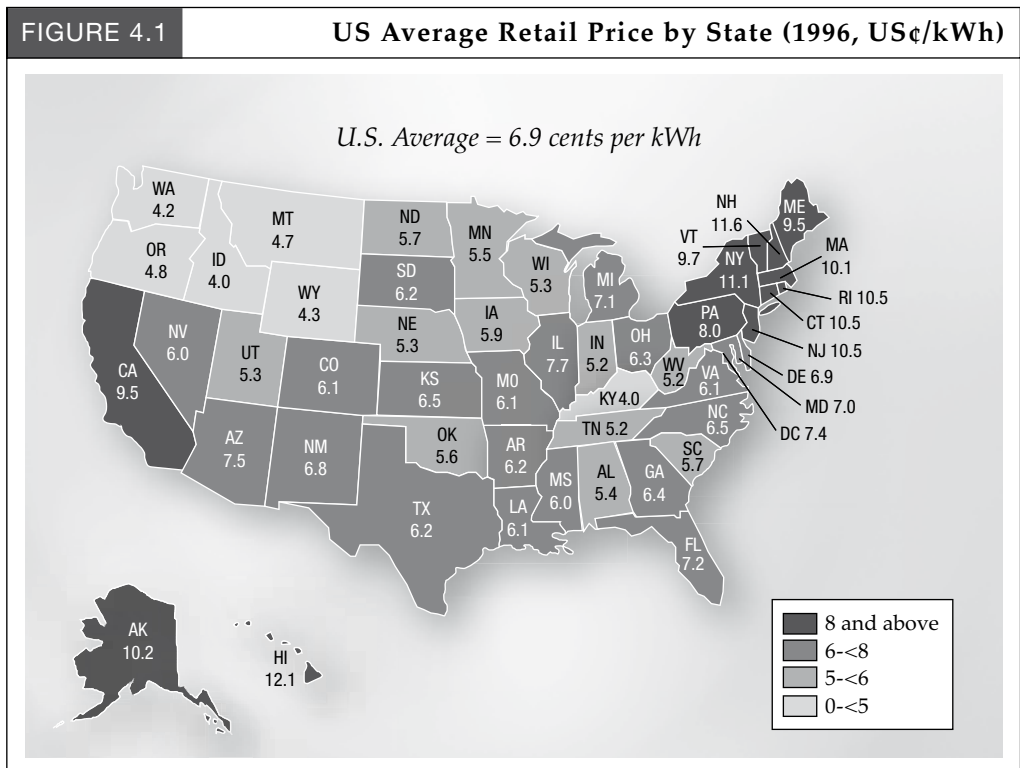
Various federal initiatives and nationwide imperatives have given rise to state-by-state reforms of the US electricity system. Federal legislation in 1978 required utilities to allow often-times cheaper, smaller non-utility generators access to their transmission assets and to buy energy from them at avoided cost. Later legislation, in 1992, extended these requirements to inter-state transmission assets and exempted certain non-utilities from the restrictions of the 1935 legislation, giving rise to 1996 Federal Energy Regulatory Commission (FERC) Orders 888 and 889, creating wholesale competition by mandating non-discriminatory transmission access for non-utilities, requiring utilities to electronically share information about transmission capacity, and ring-fencing transmission from generation and retailing.

At a more basic level, disparities in electricity prices across states, as illustrated in Figure 4.1, were both a source of and political impediment to reform. In part these disparities reflected a fundamental pitfall of the rate-of-return-based system of regulated private monopolies

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<sup>2</sup> Michaels (1996) cites research showing that regulation first came to states where utilities' profits were squeezed, rather than those where electricity prices were excessive, reflecting the fact that early calls for regulation came from industry, not consumers.

in the US, namely the shifting of investment risk from investors to consumers, combined with the problem of regulatory capture by interest groups (e.g. trading off higher electricity prices for clean air). The “cost plus” presumption underlying this approach, combined with a tendency to invest in excess capacity to ensure supply security while lacking strong incentives for efficient investment, effectively enabled utilities to recover from consumers returns on poor or inefficient investment decisions that would otherwise be losses borne by shareholders.<sup>3</sup> The situation was made worse by long-term supply contracts at times being struck at historically high prices – and US consumers in various states found themselves paying electricity prices considerably higher than those in neighbouring states or other countries. The persistence of such disparities in a nationally interconnected system must have been some cause for concern (i.e. subject to inter-state transmission charges, broadly speaking electricity charges should have tended to converge).



Source: EIA (1996).

<sup>3</sup> To complicate matters, Van Doren and Taylor (2004) note that return-regulated utilities often employed weighted-average pricing, which could in fact result in lower electricity prices than those expected in reformed electricity markets where “market-clearing” or “marginal” electricity prices prevail. They point out, however, that this simply meant that such average electricity prices “were wrong all the time” – too low on-peak and too high off-peak – and encouraged excessive consumption, requiring under-utilised investment in peaking generation funded by excessive off-peak prices.

As a consequence those states with the highest prices were also the first to institute reform, notably California, and Pennsylvania/New Jersey/Maryland (PJM).<sup>4</sup> While the PJM reforms can be regarded as successful as any, the Californian reforms provided a signal example of how not to restructure an electricity system, and simultaneously highlight a challenge for US reformers attempting a transition from rate-of-return regulation of monopolies to liberalised arrangements.

### *California*

Settling on a hybrid of the England and Wales initial (pool) and eventual (NETA, decentralised bilateral) wholesale markets, generation in California was dominated by three utilities which had successfully persuaded regulators to enable them to fully recover all “sunk costs” from past investments irrespective of their merit. To do so the California reforms effectively fixed retail electricity prices, which is not of itself unusual, but they did so at much less than the cap applicable to wholesale prices. To compound matters, long-term contracts were precluded, with all wholesale purchases required at spot prices. As this was combined with an obligation on the utilities to supply at the fixed retail price, it should be no surprise (even without hindsight) that the sector was at risk.

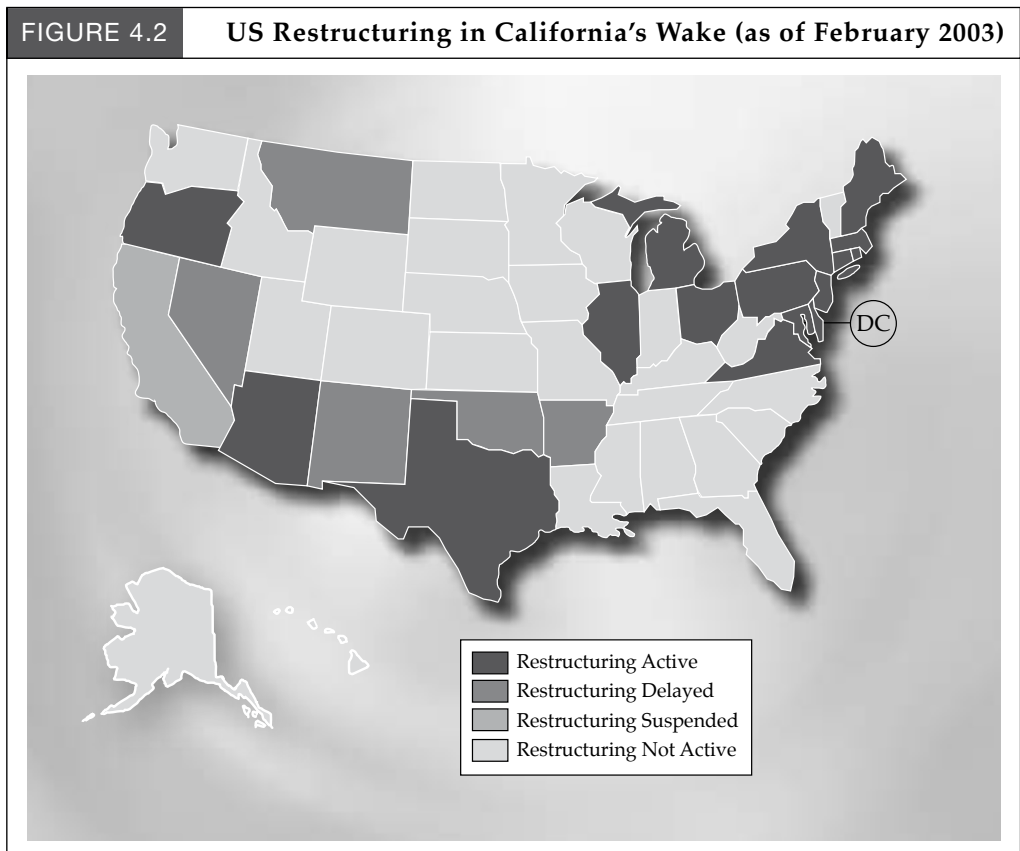
With a hotter-than-usual summer and dryer-than-normal year (reducing hydro inflows), and strong economic growth feeding into increased electricity demand, the state’s electricity supply situation in 2000 began to tighten. Combined with sharp increases in gas costs and the price of pollution permits, the wholesale price of electricity in California quickly began to climb. Commentators have argued that these price rises were exacerbated by, among other things, retailers and generators with market power (the latter by withholding capacity) and by the state’s system operator not credibly enforcing price caps. The immediate result was that regulated utilities were forced to supply energy at low fixed prices (giving consumers no direct incentive to conserve), which they bought for supply at considerably higher wholesale prices. Their losses amounted to millions of dollars each day, and as a consequence in March 2001 the state’s largest utility filed for bankruptcy. The longer-term consequences are even more dire, however, with a government knee-jerk reaction to the crisis resulting in it entering into supply contracts with generators for terms of up to 20 years at prices which reflected the crisis but which now appear high.<sup>5</sup> By generators successfully lumbering consumers with historical sunk costs under the reforms, Californian electricity consumers now face 20 years of new ones.

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<sup>4</sup> PJM now covers Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia.

<sup>5</sup> Borenstein (2002) notes that the state committed to US\$40 billion in long-term electricity contracts at prices likely to be more than 50% higher than expected future spot prices.

The 2000 disaster in California's electricity system gave reform a bad name, tending to overshadow the progress of PJM.<sup>6</sup> The state did not implement deregulation in the strict sense of liberalisation, but shifted the burden of one form of regulation – the ability of utilities to recover sunk costs – into a semi-liberalised context with the same effect, resulting in an awkward hybrid of price-fixing and market forces. Whereas nationalised electricity systems provide reformers with a degree of freedom to liberalise despite any adverse consequences to the taxpayers who funded investments in the sector, the dominance of shareholder-owned utilities in the US makes reform more of an arm-wrestle, with inevitable compromises being the result. It is no surprise that in the light of California's experience – and despite successes elsewhere in the US and internationally – electricity sector reform in the US is now proceeding with considerably greater caution.



Source: EIA (2003a).

<sup>6</sup> It should be noted that PJM represents one of the more lauded models of electricity reforms. PJM operates the largest competitive wholesale electricity market in the world, and new membership is scheduled, doubling the size of the territory it serves.

## AUSTRALIA

*Partially Converging State Reforms*

At the national level, electricity reform in Australia is unlike that in England and Wales, and is distinguishable from that in the US. Whereas the England and Wales reforms were applied to a unified and government-owned national system, national reforms in Australia have been directed at bringing together disparate state-government-owned systems having little existing interconnection or trading into a centralised wholesale market facilitated by inter-state transmission. And while national reform in the US has also been directed towards increasing wholesale competition, it does so through a greater existing level of interconnection and between predominantly investor-owned utilities. Once reform is considered at the state level, however, particularly in Victoria, comparisons are more easily drawn between Australia's reforms and those in England and Wales.

*Reform Background*

Prior to reform, electricity was supplied by state-level public-owned vertically integrated concerns. Given the vast distances between population centres, interconnection via high-voltage grids had been slow to develop, if at all. With most of the Australian population concentrated in the eastern seaboard, greatest progress towards a unified national system has occurred in Queensland, New South Wales and Victoria. Federal-government involvement in the sector was limited to co-ownership of a small amount of hydro generation in the Snowy Mountains, and less directly via competition law and controls on matters such as state borrowing, taxation, and foreign ownership.

*Reform Motivation*

National reform of the electricity sector has had multiple motivations. In 1990 the Industry Commission, a federal body responsible for improving economic efficiency, was charged by the federal government to consider the merit of a national transmission system. Citing poor investment decisions, excessive staff levels and cross-subsidies in electricity prices, it recommended that generation, transmission and distribution/retailing be unbundled, state transmission systems be combined into a national grid, transmission and distribution/retailing be corporatised, competition be introduced into generation, and that energy prices reflect costs and be free of cross-subsidies. Following these recommendations, a Special Premiers' Conference in 1991 agreed to the formation of a National Grid Management Council to develop a National Electricity Code, in consultation with industry and others, setting out operating rules for a National Electricity Market (NEM). Further impetus for reform came from a 1993 review of national competition policy, the Hilmer Commission Report, identifying benefits to the Australian economy from the reform of various industries, including electricity, and the 1994 agreement of the Council of Australian Governments (COAG) to develop a code of conduct for the operation of a national grid.

### *National Electricity Market (NEM)*

The NEM commenced operation in December 1998 with a key objective of promoting competition throughout its component electricity sectors. Extending early trading between Victoria and New South Wales (including Australian Capital Territory, ACT), it also includes limited trading with Queensland and South Australia, supplying electricity to almost 8 million customers. As in the England and Wales pool, wholesale prices are determined through a centralised market, although participants are free to enter into hedge contracts to manage their price risk. Prices are determined day-ahead for five-minute intervals in half-hour trading periods at six regional reference nodes (one for each participating state plus Snowy Mountains) to ensure that least-cost supply is dispatched to meet instantaneous demand. Generally participation in the NEM is compulsory, although generators selling all of their output directly to a local retailer or customer are permitted to do so outside of the spot market. The National Electricity Code is administered and enforced by the National Electricity Code Administrator (NECA). Transmission connections between states are subject to rate-of-return regulation under Australia's general competition law watchdog, the Australian Competition and Consumer Commission (ACCC). Regulation of distribution prices is implemented at the state level, and even some energy price caps remain.

In 2002 NECA reported on the performance of the NEM, generally expressing satisfaction at progress since its inception. Benefits realised by 2000 were estimated to be A\$1.5 billion, and forecasted to grow to A\$15.8 billion by 2010. Household electricity prices in Brisbane, Sydney and Melbourne were found to have fallen in real terms by between 1% and 7% between 1990/91 and 2000/01. Reliability and security of the NEM was high, and a majority of new investment in generation and interstate transmission was privately financed, with lead-times shorter than in the past. Also in 2002 COAG released its own, less-upbeat energy market review, citing concerns such as overlapping and conflicting regulation, conflicts of interest where state governments acted as owners, regulators and policy makers, the occasional exercise of market power by generators (particularly in New South Wales), and difficulties in planning for transmission investment in the decentralised environment. It did, however, find the NEM to provide a sound mechanism for signalling new investment requirements.

### *Reform Progress*

In terms of state-level deregulation the early and most significant movers were Victoria, New South Wales and South Australia, all of which commenced proceedings in the early 1990s. Queensland began its process relatively late, in 1997, but has been able to participate in the NEM. Western Australia was a late and less ambitious reformer, and not only does geography currently preclude its participation in the NEM, but its sector remains government-dominated (albeit incompletely) and vertically integrated. The Northern Territory is also unable to participate in the NEM, and currently has no intention of reforming its vertically integrated, government-owned and -operated state electricity sector.

### *Victoria*

The Victorian reform experience bears a number of similarities to that in England and Wales, although without radical re-reforms. When a new government took office in the debt-laden state in 1992, it quickly set about the process of restructuring. The State Electricity Commission of Victoria (SECV) – until then a vertically integrated state monopoly in generation (but for a 51% stake in one generator owned by Mission Energy), transmission and distribution/retailing – was vertically separated into its component parts and corporatised. Generation was separated into five competing and independent companies, and the 29 distribution/retailing companies were amalgamated into just five. Transmission was set up as a stand-alone company, and the Victorian Power Exchange (VPX) was set up to operate a wholesale market and to dispatch generation (a role often left to the transmission operator). All of these assets were subsequently privatised at what transpired to be favourable prices, with mostly US but also UK acquirers. The five distribution/retailing companies were permitted to retain exclusive franchise areas, although these were successively removed (as in England and Wales) starting with larger customers and with all customers contestable by the end of 2000. Transmission and distribution prices, and (prior to the removal of franchise restrictions) energy prices, were subject to CPI-X regulation administered by a new state-level regulator, the Office of the Regulator-General.

With the transition to the NEM, responsibility for managing the wholesale market passed from VPX to the National Electricity Market Management Company (NEMMCO), and both generation and retailing were augmented by their counterparts from other states. While politically an intensely sensitive issue, privatisation (including that of transmission) netted the state A\$22.5 billion by 1997 – potentially over-the-money at the expense of US and UK investors – which it used to reduce state debt. At the same time consumers enjoyed reduced electricity prices, with the greatest gains being at the commercial and industrial levels rather than residential.

### *Rapid Change*

The Australian experience with electricity sector reform would appear to be encouraging. Considerable progress has been made in less than 15 years: from a disparate collection of state-level government-owned monopolies, to the establishment of a functioning national electricity market based around increasingly reformed sectors in its constituent states. As such, Australia is enjoying not only the gains from greater competition in generation and retailing but also from rapid interconnection of states giving rise to greater opportunities for competition and customer choice. The Victorian example, in particular, with echoes of the England and Wales experience (but without some of the stumbles), has demonstrated that the gains from reform can extend well beyond lower electricity prices, including the potential for considerable asset sale proceeds. It has also demonstrated that private ownership in the sector, even by foreign concerns, can usefully contribute to the achievement of reform objectives.



## EUROPEAN UNION

### *Background*

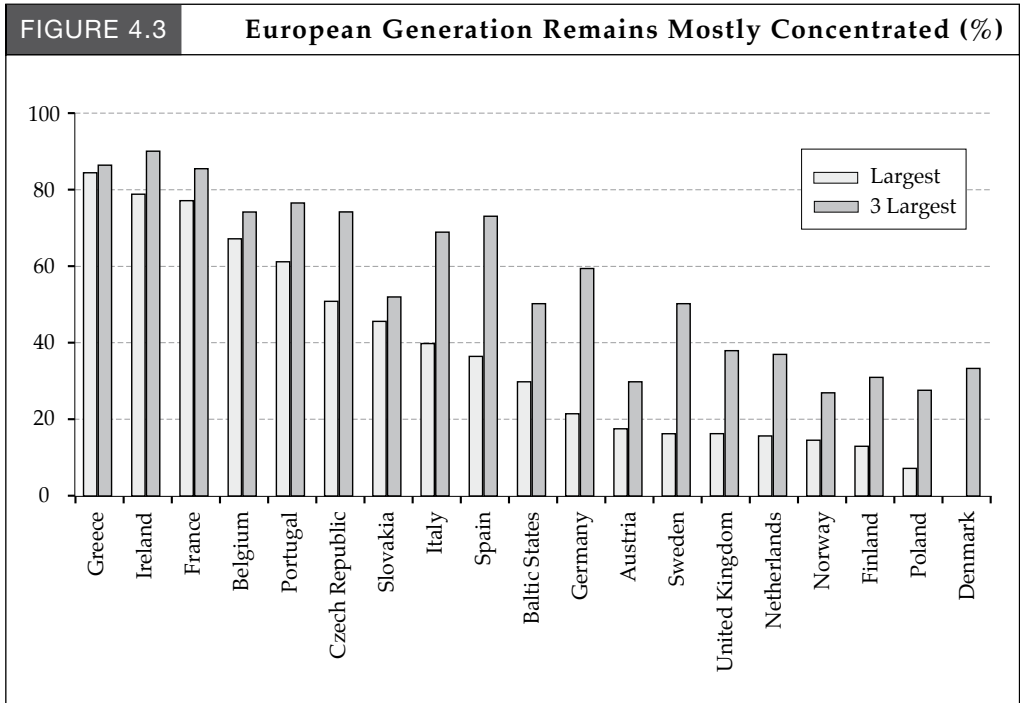
As elsewhere, in the late nineteenth century private companies dominated electricity provision in Europe. State involvement increased with the development of new generation, and following World War II most European governments inclined towards electricity organised as state-owned national or regional monopolies. With technological advances facilitating a more decentralised operation of interconnected electricity systems, increased inter-state electricity trading, and the European Union's gradual shift towards common European markets, the past two decades have seen a developing interest in implementing reforms of the type spearheaded in England and Wales and other key European states.

### *EU Reform Directive*

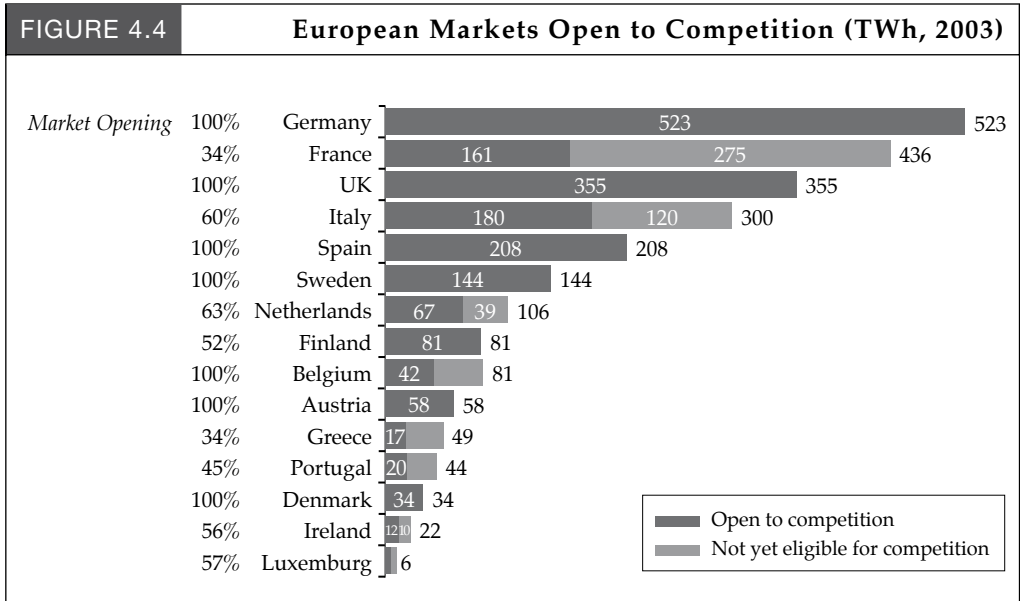
In February 1997 the EU Directive 6/92/EC came into force, setting out general rules – in the form of minimum requirements rather than an imposed model – which member states were to incorporate into domestic legislation by certain dates (2001 by the latest). Most member states transposed the Directive's requirements into domestic law as scheduled, with Italy and France (which in 2004 remains dominated by state monopoly EDF and has opened only 34% of its market to competition) being the notable exceptions. Legal action by the European Commission against the latter has been launched. By contrast, England and Wales, Norway and Sweden were all early-adopters, having begun their reform processes long before the Directive was issued, and having shaped the Directive's form. Germany made later but significant moves towards liberalisation with 1998 legislation enabling competition at all levels of its electricity sector, but this has been seen to favour the expansion strategies of the sector's dominant companies.<sup>7</sup>

New generation in member states was to be subject to objective, transparent and non-discriminatory criteria, with either each state determining and tendering the rights to additional capacity, or simply authorising investments that met pre-determined criteria. Electricity retailing was to be progressively opened up to competitive supply, allowing time for other market reforms. Electricity regulators were to be set up independent of industry and everyday political control. While formal electricity markets were not mandated, three models were offered to facilitate electricity trading across transmission networks. The single-buyer model provided for monopsony purchasing of wholesale electricity from competing generators, the negotiated third-party access model allowed generators and purchasers to negotiate terms of supplies and network access, and the regulated third-party access model provided for the regulator to impose non-discriminatory tariffs for transmission and distribution access. Most large to mid-sized European Union members opted for the regulated third-party access model and authorisations for new generation, with the notable exception being Germany (which opted for negotiated third-party access, with a single-buyer at the local level).

<sup>7</sup> See the chapter by Mez in Glachant and Finon (2003).



Source: O'Donnell (2004).



Source: O'Donnell (2004).

*Further Reform*

In June 2003 the European Union passed a new Directive (2003/54/EC) and Regulation (12/28/2003) effective July 2004, revising and expanding the earlier Directive. Transmission and generation was to be unbundled, with all non-residential customers to be available to competing suppliers by July 2004 and all customers by July 2007. Open access to transmission and distribution systems was to be mandatory, and published rather than negotiated tariffs. While a single internal European electricity market remains the EU's goal, progress has been achieved at widely varying rates, and constraints in inter-state transmission interconnections mean that it is not yet feasible. Instead five autonomous subsystems have emerged, in Ireland, the United Kingdom, the Iberian Peninsula, Greece, and Scandinavia.

Potential regional electricity markets currently exist, or are expected to evolve by around 2008, in Ireland, the United Kingdom, the Iberian Peninsula, Italy, Scandinavia, the Baltic, and West, East and South Europe. The early-moving European reformers led the way in international terms, yet the balance of Europe, notably including France, must be regarded as relatively slow to open their electricity industries to internal and external competitive forces.



*In this chapter we explore the history of contemporary electricity reforms in New Zealand, focusing on issues of policy and reform objectives, regulation, ownership, and structure. It is suggested that New Zealand has enjoyed a unique capacity for reforms not shared by other countries, but that it has not uniformly exploited its advantages in implementing reform. Its outcomes have, as in other countries, been mixed, although New Zealand has avoided certain fundamental errors that in at least one notable case, that of California, resulted in outright disaster. No reforming jurisdiction, including New Zealand, can claim to have implemented a perfect or complete reform process. The question remains as to whether New Zealand's reform path has positioned it well for ongoing developments in the sector, or whether the future enhancements will be unduly difficult to achieve because of earlier wrong turns.*

*We begin with a brief discussion of the origins of electricity in New Zealand, and how its provision quickly became the exclusive purview of government. The 1980s reforms of electricity are summarised, focusing on the corporatisation of ECNZ under the State-Owned Enterprises Act 1986, early reform objectives, and the 1989 Electricity Task Force Report. Any break-up of the monolithic ECNZ necessitated measures to encourage competition in generation, such as the separation of transmission from generation, and development of a wholesale electricity market. Two major studies, WEMS and WEMDG, provided impetus for the latter, beyond that of the 1991 pricing showdown between ECNZ and the then National government.*

*The electricity industry progressed reasonably independently in the early 1990s until the June 1995 reforms pushed the issue of ECNZ separation, spawning the birth of Contact Energy and enabling the wholesale electricity market to begin in earnest. They also set the scene for a rapid industry realignment, following controversial 1998 reforms forcing the separation of distribution from competitive activities such as energy retailing and generation. These reforms – now at the distribution end of the industry – followed the ownership and organisational reforms of 1990 and 1992, opening up traditional ESA supply franchises to retail-level competition. While such competition was initially slow to emerge, it quickly gained pace after the 1998 reforms, which also resulted in measures to enable customer switching.*

*New Zealand's implementation of light-handed regulation – relying on competition and disclosure rather than heavy-handed industry control – is critiqued. Following a change of government in 1999 and the 2000 industry inquiry, it was soon replaced with explicit regulation that was based on questionable arguments. With major reforming legislation in 2001, rapidly followed by more extensive reforming legislation, industry control has passed to a new Electricity Commission with wide regulatory discretions. Despite these powers, the Commission faces external challenges which will prove hard to surmount. Its advent marks a turning point in New Zealand's reform process.*

## INTRODUCTION

*International Context*

It is not possible to directly compare New Zealand's reform progress with those of other countries since the nature and pace of reform has generally been dictated by each country's idiosyncratic historical, political, social, physical, and economic environments. Despite overlaps in broad objectives, no two countries' reforms have been the same, and even within countries (such as Australia) marked differences in reform agendas and processes can be discerned. Later reformers certainly owe a debt to earlier reformers, and valuable lessons have been learnt by observing reform processes around the world, but in the main each country has embarked on a process of trial and error informed by evolving understandings of both theory and practice.

*Domestic Context*

It is useful to consider the contemporary reform of the New Zealand electricity sector not only in the context of reforms such as those described for other countries in Chapter 4, but also against the New Zealand environment leading up to the reforms. Once ranking in the upper echelons of OECD economic comparison, by 1984 the country's fortunes had dramatically changed. As summarised in Evans *et al.* (1996), in the decade to June 1984 net public debt rose from 5% of GDP to 32%, annual inflation was in double digits except for the last part of this period (and only then because of an imposed wage and price freeze), and the unemployment rate had risen from 0.2% to 4.9%. By the end of this period the current account deficit in the balance of payments had risen to 8.7% of GDP, and the government's financial deficit stood at 6.5% of GDP. GNP per capita had fallen from 92% of that in the US in 1938, to around 50%.

But these were merely symptoms of a more deep-seated malaise. By 1984 the New Zealand economy was highly protected, regulated, centrally administered, and heavily taxed. Agricultural production was subsidised, domestic industry protected by various instruments including high tariffs on imports and foreign exchange controls, and all manner of activity was subject to distortionary and often-times *ad hoc* regulation. The playing field was heavily fenced, full of bumps, and tightly controlled. Resulting inefficiencies in the private sector were reflected in their government counterparts, with considerable taxpayer investments in a range of sectors showing little or no financial return as well as poor service delivery. Both financial and labour markets were also tightly and centrally regulated.

*Existing Arrangements Unsatisfactory*

By 1985 it was apparent that in terms of generation, at least, these arrangements were not performing well. As noted in the Ministry of Energy's review in 1984, the Electricity Division's performance measurement was complicated by electricity pricing being set externally, it paid no tax, it required considerable capital, and its "essential nature" and

“monopoly role” made it a target for industrial action. The review further noted that because the Division was an essential part of the country's infrastructure, it could influence the scale and direction of economic development, thus attracting political and economic attention.

A 1985 Treasury review of electricity planning and electricity generation costs made especially sobering reading. Noting the significant share of the country's total investments represented by the electricity sector, the report found that prevailing arrangements were failing to deliver electricity in New Zealand at lowest practicable cost – the driving policy of the day. Over-investment in generation arose from systematic and gross over-estimates of demand growth, ranging between 33% and 51% for the periods considered. Projects were characterised by commissioning delays, large cost over-runs and electricity production costs well in excess of those predicted (at times up to 100% higher). It was even found that generation investments were not undertaken on a cheapest-first basis, whether using simple or more refined investment selection rules. Aside from the general need to reform New Zealand's state trading enterprises, electricity was especially in need of change.

Similar concerns were highlighted in a 1987 Audit Office report, which noted delicately that “one could conclude that the money committed [to new hydro generation projects 1977–1984] may have been better utilised elsewhere for the benefit of the nation”. The report also noted that the economic criterion for construction of new generation was not adjusted downwards despite major reductions in electricity demand growth forecasts – in other words investment was made in projects that were uneconomic even given available revised forecasts. It further criticised governance arrangements surrounding loans for these schemes, where the Crown offered Supplementary Operating Loans to ESAs, thus assuming all financial risks with the individual schemes despite there being no financial or time limits placed on the availability of these loans.

It can only be surmised whether similar inefficiencies occurred at the distribution and retailing level, as scant operational data for this period are available, commercial performance standards were not mandated or utilised, and performance appraisals were not apparently required. The electricity system of the time would appear to have been driven by political (central and local government), engineering and labour imperatives as much as by the interests of taxpayers and electricity consumers.

## HISTORICAL BACKDROP

While New Zealand's electricity system is geographically isolated from those of other countries, it shares large parts of the thinking applied in its counterparts elsewhere. In its structure and operation it was, at the commencement of the contemporary reform process, not unlike electricity systems in countries such as England or Australia, with government ownership and pricing and investment decisions centrally driven by multifarious objectives

and interests. At the heart of the reforms was dissatisfaction with the performance of such arrangements, a need to reduce government budget deficits and a desire to inject market disciplines (and capital) into the activity and evolution of the sector.

New Zealand was no laggard in the development of its electricity system and the institutions that govern and affect its operation. Reflecting its pioneering beginnings with European colonisation in the nineteenth century, from the mid-1880s industrial concerns such as flour mills and a gold-mining crusher (a world first), and small communities needing street-lighting, were early-adopters of the new energy.<sup>1</sup> As the nation developed and demand for electricity grew, the potential for transmitting electricity generated using the country's many lakes and rivers to its major population centres led to the development of a national transmission grid. At the same time local distribution grids were developed to ensure that even rural users distant from population centres could be supplied, reflecting the importance of the new energy to the development of the country's agricultural base. As a nation we were able to boast a number of "firsts" in the electricity sector, such as the world's largest high-voltage direct-current (HVDC) link, and the then largest earth dam in the southern hemisphere (Benmore, located in the South Island and operational from 1968). Since its beginnings, electricity has undergone a sequence of paradigm changes that reflect the state of the technology in generation and distribution, and political and economic institutions and notions.

Although the innovations often began with the endeavours of individuals or private concerns, the development of New Zealand's electricity system quickly became the concern of local government, and soon afterwards of central government. With the passage of the Water Power Act 1903, government reserved the sole right to itself to use water for generating electricity, or to grant the right to others, thus creating a state monopoly on future hydro-generation developments. The first major state hydro scheme, Coleridge, was completed in 1914, almost 30 years after the first major private hydro development at Bullendale. Funding and coordinating the large-scale development of hydro-electric power schemes was deemed a national priority, and bringing together dispersed electricity generators and consumers through a nationwide transmission grid resulted in central government ownership and control of New Zealand's generation and transmission capacity (with distribution assets remaining in local government control), including through the state's acquisition of private generation.<sup>2</sup>

The focus in New Zealand was for a long time the ongoing development of an electricity sector that could meet the growth in electricity demand arising as a consequence of strong growth in the national economy. Eventually, however, and perhaps as a consequence of central government control of generation in particular, it became inevitable that electricity

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<sup>1</sup> The first use of electricity in New Zealand is attributed to a telegraph line between Dunedin and Port Chalmers in 1861, by Murray and Shepherd (2002), who argue that the history of electricity has consisted of a series of paradigm shifts. David and Bunn (1988) analyse some of the historical technological conflicts in electricity.

<sup>2</sup> See Associated Group Media (1984) and Martin (1998).



consumers should become apprehensive about any monopoly power in the industry, now that electricity had become as integral as running water to modern living. To an extent, however, the excesses of a state-owned monopoly were regarded as less than those likely with a profit-motivated private operator, and could be traded against quality and security of supply, even if existing arrangements did not in fact deliver these.

## THE REFORMING 1980s

### *Reforming Government*

A reform- and liberalisation-minded Labour government came to power in 1984, following which New Zealand embarked on an aggressive programme of economic restructuring and liberalisation aimed at improving the nation's economic efficiency. Financial markets were deregulated, and subsidies and tariffs either abolished or phased out. The state sector was restructured to enhance accountability and performance. Government expenditure was cut, and user-pays policies adopted. State-owned trading enterprises were corporatised and subjected to increased commercial disciplines while being given greater operational autonomy, in many cases leading to privatisations. Industry-specific regulation was replaced by a common competition policy under the 1986 Commerce Act entailing a "light-handed" approach. And most of this occurred in the first five years. For much of the past 20 years the broad thrust of these reforms has been maintained, although less so with time. In part this change in reform direction reflects the shift from a first-past-the-post electoral system to mixed-member proportional representation (MMP) in 1996 following a 1993 referendum, and reinforced by the election of Labour-led coalition governments in 1999 and 2002.<sup>3</sup>

### *From Government Department to Corporation*

In the current context, the reforms of greatest significance began with the corporatisation of state trading enterprises under the 1986 State-Owned Enterprises (SOE) Act. Motivating this shift towards operationally autonomous, profit-motivated and more transparently operating state trading activities was their sustained poor performance under existing arrangements. One measure of this poor performance – lack of investment returns to taxpayers – is exemplified by the following:<sup>4</sup>

Over the twenty years to 1985/86 the government invested \$5,000 million (in 1986 dollars) of taxpayers' money in the departmental trading activities of the Airways System, the Lands and Survey Department and Forest Service, the Post Office [which then included

<sup>3</sup> Buckle and McLellan (2003) point out that following the reforms of the 1980s, New Zealand's economic position relative to other OECD countries has been maintained, halting the steady decline in relative economic position occurring from 1975 to 1993.

<sup>4</sup> Evans and Boles de Boer (1996) consider evidence of more-broadly defined efficiency gains from deregulation in the case of New Zealand telecommunications.

telecommunications], the State Coal Mines, and the Electricity Division of the Ministry of Energy. In 1985/86 these organisations managed assets valued at over \$20 billion but returned no net after tax returns to taxpayers.<sup>5</sup>

Up until this time the electricity sector in New Zealand was dominated by the Electricity Division of the Ministry of Energy, which was responsible for the operation, maintenance and development of all generation and transmission in New Zealand to ensure the reliability and quality of supply and to meet growth in electricity demand. Distribution and retailing services were local-government owned and operated by 61 electricity supply authorities (ESAs), including electric power boards and municipal electricity departments. Each had monopoly-service rights and obligations in licensed franchise areas, supplying energy over their lines networks purchased from the Electricity Division at prices (bundling energy and transmission charges) essentially determined by government. To enhance their bargaining/lobbying power, these organisations combined forces via the Electricity Supply Association of New Zealand (ESANZ). This basic set-up had persisted for much of the twentieth century.

#### *Early Policy and Reform Objectives*

The first major expression of reform was the creation of the Electricity Corporation of New Zealand (ECNZ) under the SOE Act 1986 on 1 April 1987 to take over the ownership and operation of the Electricity Division's generation and transmission assets. At the same time electricity generation was deregulated, allowing any party to engage in the business of generation. With ECNZ a stand-alone tax-paying commercial enterprise enjoying greater operational autonomy than its predecessor (including over the all-important questions of electricity pricing and investment), it was intended that the New Zealand electricity sector would enjoy considerable efficiency gains producing significant payoffs to the taxpayer (in the form of ECNZ tax and dividend payments) and to consumers (through reduced electricity prices). Despite the corporation's unpopularity from the outset – made worse with the 1992 winter power crisis (see Chapter 6) – its early performance was encouraging. Reflecting an attempt to stave off impending competition from new third-party generation and the then existence of excess generating capacity, ECNZ adopted early policies of reducing electricity prices in real terms, with a fall of 12% enjoyed by 1991. By that time ECNZ had also paid more than \$500 million in tax and almost \$1 billion in dividends to government.

While efficiency was the early driver of reform, it was not long before the buffer created between government and ECNZ under the SOE Act 1986 faced and glaringly failed its first test. As excess generation capacity began to fall and ECNZ's dominant position appeared secure, the corporation attempted a change in pricing policy to better prepare for the need for new generation investment. In 1991 it announced a planned increase in the wholesale electricity price (as it was still able to do, given its monopoly position)

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<sup>5</sup> Jennings and Cameron, "State-Owned Enterprise Reform in New Zealand", in Bollard and Buckle (1987).

and found itself met with ESA revolt and direct government opposition to the move.<sup>6</sup> Eventually electing to back down rather than have its independence pointedly removed, ECNZ's board adopted an eventual price rise of 1.5% and recognised that centrally determined pricing by the corporation would be subject to political involvement. At the same time an ongoing debate about the future ownership of ECNZ came to a conclusion, with the recently elected National government backing away from privatisation in favour of the status quo. Equity and other political constraints such as public opposition to privatisation – also including environmental concerns which had found greater expression with the passage of revised resource-management law (the Resource Management Act) in 1990 – were now being given prominence.

## OWNERSHIP, STRUCTURE & REGULATION – THE 1989 ELECTRICITY TASK FORCE

In terms of electricity industry policy more specifically, various initiatives were instigated in these first five years of ECNZ. In 1988 the government established an Electricity Task Force comprising various ministries and ECNZ (later also including the ESAs) to review the structure and regulatory environment of the bulk electricity supply industry (later expanded to encompass the whole electricity sector). Building on earlier work and decisions regarding distribution sector reform, and subject to the government's overriding objective of economic efficiency, the Task Force's main recommendations are summarised in Box 5.1.

## RESPONSES TO THE TASK FORCE REPORT

### *ECNZ Break-up Examined*

Following the Task Force's recommendations, the government sought ECNZ's views on potential break-up arrangements. The aim of such break-up would be to induce sufficient competition to encourage decentralised decision-making and market-based pricing, reduce barriers to entry and ECNZ's dominance of generation, and facilitate privatisation without regulation. At the same time the costs and risks of any break-up were to be minimised, to assure supply reliability, minimise coordination costs, and to avoid financial failure, erosion of privatisation proceeds and unnecessary investment. ECNZ responded in 1990, concluding there was no substantial case for break-up – that vertical integration was relatively efficient and led to better coordination than would decentralised decision-making, and that the break-up benefits would likely be insufficient to outweigh the risks and costs – but that the England and Wales experience demonstrated its feasibility. The corporation identified up to

<sup>6</sup> ECNZ (1991) argued that the planned increase was required in order to approach the long-run marginal cost of additional generation (although the evidence in Chapter 3 might be interpreted to suggest otherwise).

## BOX 5.1

## Summary of 1989 Electricity Task Force Recommendations

**Transmission:**

- 1) Ownership separation of ECNZ's generation and transmission assets.
- 2) Corporatisation of transmission, with resulting company Transpower to be owned by a "club" of generators and distributors.
- 3) Light-handed regulation under the Commerce Act 1986 to continue, with specific regulation imposed only if shown to be necessary.

**Generation:**

- 1) No large-scale break-up of generation (due to costs and risks).
- 2) Further study of minimising entry barriers by light-handed regulation, or by limited break-up and accelerated development of a wholesale electricity market.
- 3) Privatisation of ECNZ subject to the successful minimisation of entry barriers (although ESAs opposed privatisation and sought price control while ECNZ dominant).

**Distribution/Retailing:**

- 1) Confirmed earlier recommendation that ESAs be corporatised and their franchise areas and supply obligations be removed.
- 2) Privatisation by share listing.
- 3) Regulation as for transmission – but energy charges to be unbundled from transmission and distribution charges, and performance measures to be developed.
- 4) Vertical integration between generation and distribution to be subject to normal provisions of the Commerce Act 1986 (although the Ministry of Energy opposed any such integration and the ESAs opposed integration into retailing while ECNZ was dominant in generation).

Source: Electricity Task Force (1989).

four viable sub-groupings of its generation assets, along with a number of non-core hydro generators that could also be spun off. It added that the necessary conditions for a successful break-up included the formation of a centralised wholesale market such as the England and Wales pool (which would maintain the benefits of coordinated generator dispatch), the successful operation of which would require open access to energy retail customers. This in turn would need the separation of distribution and retailing operations, and non-discriminatory access by competing energy retailers to each distributor's local network.

*Separation of Generation and Transmission – Trans Power Establishment Board*

As a parallel work-stream, the Trans Power Establishment Board (TPEB) was created to oversee the separation of the national grid from ECNZ. In fact ECNZ had taken steps towards this end with the creation of a separate subsidiary to ring-fence transmission from its generation activities, although transmission charges were not unbundled from bulk electricity prices until 1993. The TPEB noted the natural monopoly nature of transmission, at least for the then foreseeable future. The government's desire to see transmission separated from ECNZ was motivated by a desire to develop competition in generation which necessitated open, transparent and non-discriminatory access by any competing generators and others to the grid. Favouring light-handed regulation backed with the threat of heavy-handed regulation, it advocated the introduction of a user-pays element to transmission pricing, and "club" ownership of a profit-motivated Transpower.

The Board of ECNZ argued that by generation (i.e. then ECNZ) owning 50% of Transpower and distributors/retailers the balance, the company would face the strongest disciplines to minimise costs while maintaining reliability. A company on these lines would be better able to optimise investment decisions in transmission and generation, while operational coordination across the industry would be facilitated. It regarded ongoing state-ownership as providing scope for political interference in what it argued should be commercial decisions (a matter taken up further in Chapter 8). While Transpower was indeed separated from ECNZ in 1994, it has remained in state-ownership (not least because the ESAs opposed any generator stake in the "club" and they themselves did not wish to pay for their stake). It has subsequently faced amendments to its SOE Act objectives, placing greater emphasis on economic efficiency over and above its previous profitability objective (see Chapter 8).

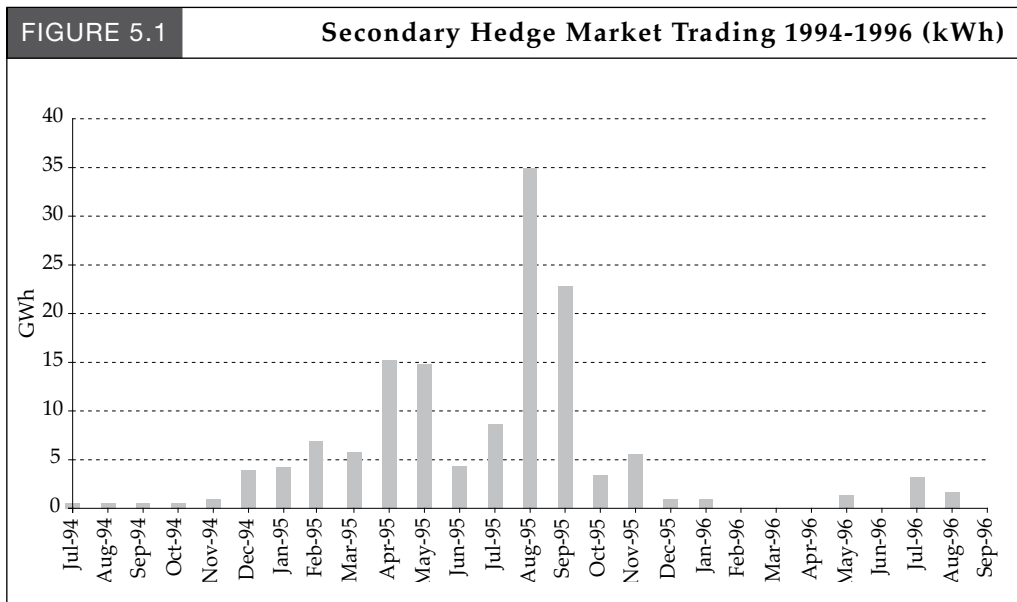
Transpower's initial pricing methodology became regarded as lacking efficiency, being based on allocating its costs and allowed profit (on a rate-of-return basis) across grid-users according to long-term historical usage. To provide better pricing signals regarding grid usage and investment requirements, the company moved to implement pricing components involving more refined usage-based charges, but met considerable resistance from distributors. Since it was obliged to supply such organisations this resulted in years of protracted litigation, only recently resolved. Work remains outstanding on creating instruments to provide better market-based signals as to the costs of grid congestion and constraints, with a long-standing proposal to implement financial transmission rights still extant.<sup>7</sup> Other points of contention included Transpower's desire to recover sunk grid costs from grid users, an initiative from which it resiled and which later was put beyond debate with a major optimisation and downward revaluation of its asset base in the company's 1997/98 financial year.

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<sup>7</sup> For an assessment of these proposals see Evans and Meade (2001).

*Wholesale Market Development*

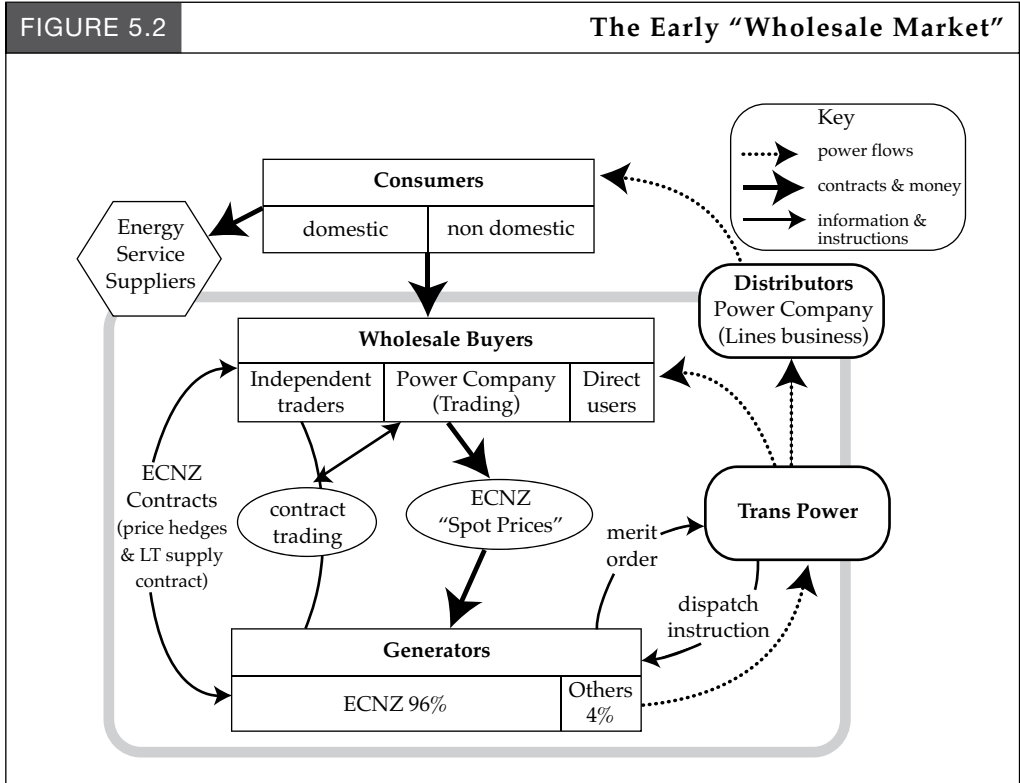
Key to the development of a competitive generation sector was the development of a wholesale electricity market through which independent generators could vie to meet electricity demand and thereby set a competitively determined market price. With the corporatisation of ECNZ in April 1987, but before a wholesale market was fully operational from 1 October 1996, various proxy arrangements were instituted to mimic such a market.



Source: Boshier and Gordon (1996).

Note: Figures for July to October 1994 are averages for the period.

Initially these comprised a combination of year-ahead hedge contracts with seasonal or monthly fixed-prices offered by ECNZ to distributors/retailers (around 90% of which would hedge between 85% and 100% of their expected load, with a bias towards winter months) and a top-up market. The latter included week-ahead half-hourly “spot” prices posted by ECNZ based on the expected short-run marginal cost of supplying electricity to meet projected demand, and capped at the cost of ECNZ’s most expensive generation (\$150/MWh). Indeed, ECNZ also created a proxy internal wholesale market of sorts in these early days by separating its generation assets into four “competing” groupings. However, the greatest degree of wholesale electricity trading in this era occurred with the commencement of secondary trading in hedge contracts from July 1994. The extent of secondary hedge trading is illustrated in Figure 5.1, with the corresponding “wholesale market” depicted in Figure 5.2. It should be noted that the single greatest trade in this early wholesale market, of 35 GWh in August 1995, amounts to one thousandth of one percent of annual energy consumption that year.



Source: Wholesale Electricity Market Development Group (1994).

Interestingly the development of a wholesale market became as much an industry initiative (if arms length SOEs can be regarded as industry and not government) as much as government policy. This was not least because the 1991 pricing showdown between ECNZ and the government, and the preclusion of ECNZ's privatisation for political reasons, fuelled a desire by the corporation to see increased competition as a means of avoiding a reversion to the government-department-like role of its predecessor.

### WHOLESALE ELECTRICITY MARKET STUDY (WEMS)

To this end, in late 1991 the Wholesale Electricity Market Study (WEMS) was established to consider the need for a wholesale market and how such a market might be structured. Supported by government, the study comprised ECNZ, Transpower, the ESAs, and four major industrial electricity users. Its recommendations are summarised in Box 5.2. The Study warned against government interventions to assist the wholesale market's development, on the basis that this would create counter-productive uncertainty regarding future interventions.

## WHOLESALE ELECTRICITY MARKET DEVELOPMENT GROUP (WEMDG)

Apparently regarded as both a little ponderous and ECNZ-centric, WEMS was followed by a government-sponsored project designed to produce more concrete proposals supported by industry, consumers, and environmental and conservation groups. Formed in 1993, the Wholesale Electricity Market Development Group (WEMDG) was to provide government with proposals, following wide consultation, for developing a wholesale market that, consistent with a new additional policy objective of “sustainable development”, ensured that electricity was delivered at the lowest cost to the economy as a whole (a rehash of “economic efficiency” which by then was becoming as politically unpopular as “privatisation”). Echoing features of WEMS, including the role of a wholesale market in encouraging demand-side responses and energy efficiency as well as investment signals and economic efficiency, the Group’s key recommendations are summarised in Box 5.3.

## EIC, M-CO, NZEM, MARIA, AND THE JUNE 1995 REFORMS

In parallel with these initiatives, an Electricity Industry Committee (EIC) was formed in 1993 comprising ECNZ and ESA representatives, and later consumers and Transpower. An outcome of its formation was the establishment of the Electricity Market Company (now M-Co) as a joint venture through which to design and implement a wholesale electricity market<sup>8</sup> (NZEM). In March of the following year industry participants agreed arrangements for metering and reconciliation of bilateral energy trading<sup>9</sup> (MARIA), enabling large users to bypass their local distributor/retailer and purchase energy from competing retailers. This was followed by secondary trading in ECNZ hedge contracts in July. With a major reform package announced by government in June 1995 – among other things announcing the spin-out of 28% of ECNZ’s generation capacity into a new SOE to be called Contact Energy – an interim wholesale market was put in place in February 1996 allowing the two generators to compete to meet demand, followed by the fully-fledged market beginning trading on 1 October that year. The establishment of the NZEM as a voluntary, self-regulated multilateral contract and industry-led initiative represented a world-first among countries engaged in electricity-sector reform.

The June 1995 reform package endorsed the development of the wholesale electricity market, stating that government would closely monitor the effectiveness of pool rules and reserved its ability to impose price controls under latent provisions in the Commerce Act 1986 and also the Electricity Act 1992 if it was not satisfied with the market’s operation. It also went on to set out overall and specific objectives for the market’s development and governance. The government’s overall energy policy

<sup>8</sup> New Zealand Electricity Market.

<sup>9</sup> Metering and Reconciliation Information Agreement.



## BOX 5.2

## Summary of 1992 WEMS Conclusions

**Facilitated wholesale electricity market is required with aims of (e.g.):**

- 1) Encouraging appropriately timed investment in new capacity as well as market-based signals for energy efficiency and conservation.
- 2) Reducing ECNZ dominance and fostering greater competition while retaining a level of system reliability commensurate with consumers' willingness to pay.
- 3) Cementing and improving post-corporatisation gains.
- 4) Giving equal emphasis to demand-side management and response.

**Aims proposed to be achieved by (e.g.):**

- 1) Separating management and control of grid from generation to allow non-discriminatory network access by any party meeting technical standards and prudential requirements.
- 2) Creating a contracts trading market with standardised contracts as a prelude to a fully operational wholesale market, aided by ECNZ posting half-hourly "spot" prices on a week-ahead basis.
- 3) Providing information services to alleviate the informational asymmetry created by ECNZ possessing and controlling critical operating data.
- 4) Appointing an Electricity Market Commissioner to "manage" the market to ensure target supply reliability and capacity was achieved, or to meet other policy objectives.

*Source:* Wholesale Electricity Market Study (5, 1992).

objective was to "ensure the continuing availability of energy services, at the lowest cost to the economy as a whole, consistent with sustainable development". Specific objectives regarding the wholesale market included promoting cost minimisation and competitive pricing, including a neutral and flexible process for changing market rules without unduly favouring any party or creating uncertainty as to future arrangements, having a robust, enforceable and neutral supervisory mechanism, deterring anti-competitive behaviour, and enabling the entry of new players (particularly those involved with new technologies or demand-side management) on unbiased terms. The ongoing independence of the market was being put on notice.

## BOX 5.3

## Key WEMDG Recommendations

**A new competitive wholesale electricity market should be established incrementally and without delay:**

- 1) Most electricity to be sold under tradable long-term contracts.
- 2) Pool/spot market to be voluntary and operated by neutral market entity (working with Transpower).
- 3) Transpower to provide neutral access to grid.
- 4) Industry-funded market coordination group with broad representation to coordinate market implementation.

**ECNZ dominance of generation to be constrained by:**

- 1) Progressively leasing 40% of ECNZ's plant to other operators.
- 2) Information on prices and quantities of all spot market offers and bids at each grid connection point (node) being made available.
- 3) 95% of ECNZ's capacity being sold under long-term contracts, falling to 80% as plant leasing progresses.
- 4) ECNZ being prohibited from owning or building (except under contract) the next generator setting the long-run marginal price for electricity, and to this end the then proposed Taranaki combined-cycle gas-generation project consents and gas supply contracts to be sold to a third party.
- 5) ECNZ being restricted to building no more than 50% of any new capacity over the following ten years and any new such investments by ECNZ being ring-fenced from existing generation to ensure new plant output prices are not influenced by other ECNZ plant.

Source: Wholesale Electricity Market Development Group (1994).

The NZEM commenced trading in earnest on 1 October 1996. Contact Energy was now competing with a diminished and restrained ECNZ (see below), which had finally been relieved of its formal obligation to supply. To ensure supply security with competing generators, ECNZ and Contact were to contract with energy purchasers for the desired level of "dry year" risk protection (see Chapter 6). Wholesale prices were not to be capped and were to respond freely to matters such as hydro reserves, thereby signalling the value of electricity if shortages should be expected or arise. Government explicitly ruled out intervening to ensure supply security for purchasers who failed to contract with generators for their desired security level. It did so on the ground that such intervention would exacerbate the risk of shortage by undermining the incentives

for market participants to take the steps necessary to ensure their desired level of security. While the market was on notice, government wished participants to find their own solutions and saw its involvement as potentially hindering such moves.

## BREAK-UP OF GENERATION

### *Tying ECNZ's Hands*

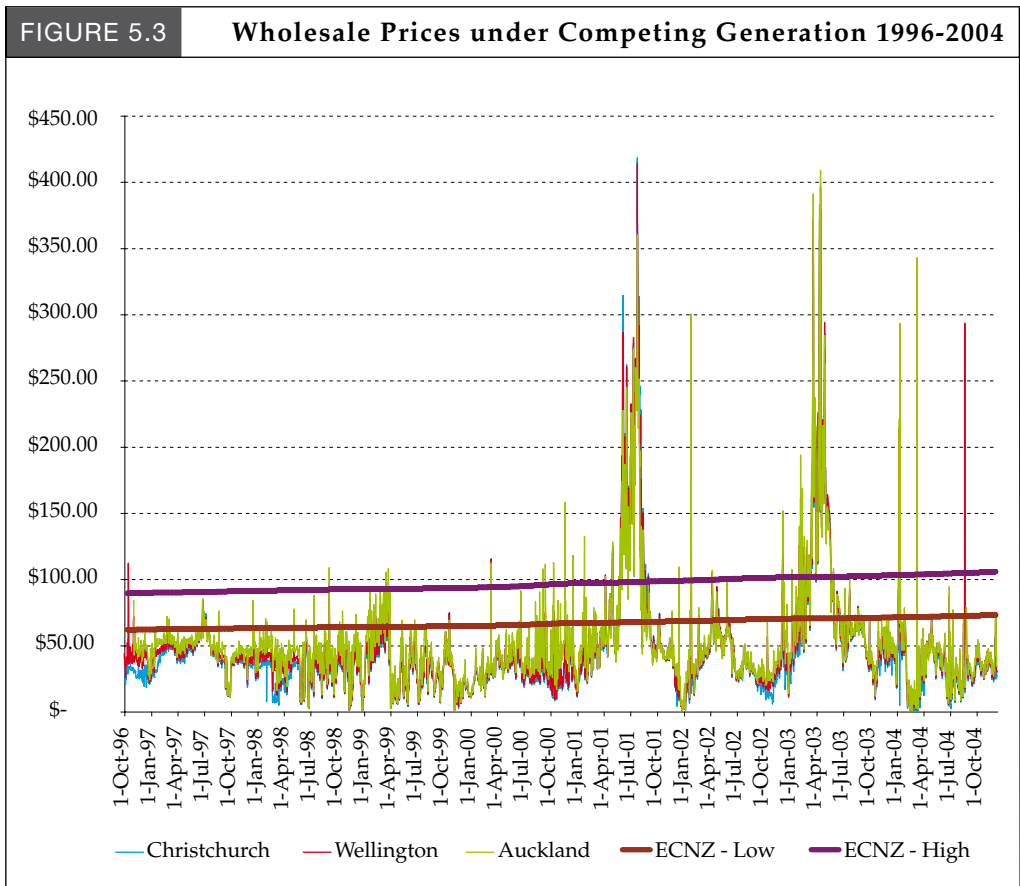
While the WEMDG proposals were not wholly accepted by government, its reform announcements of June 1995 set about implementing much of what had been recommended. A number of small, non-core hydro generators were to be sold by ECNZ to regional power companies or Maori interests, ultimately being acquired by the hitherto distributor/retailer and ascendant generator, TrustPower. More fundamentally, however, Contact Energy was to be created by spinning out generation from ECNZ – and it would have both a mixture of fuel types and geothermal and hydro development sites. As such, Contact was anticipated to provide keen competition to the diminished ECNZ and to further reduce its market share with time, and to provide further impetus for the development of the wholesale market.

This aim was assisted by restraining ECNZ from investing in more than 50% of new generation (excluding co-generation and renewable generation). ECNZ was further required to ring-fence any new generation investments to avoid their cross-subsidisation by existing capacity, which, combined with the investment cap, was intended to ensure the output prices of new capacity reflected its true costs. This was intended to provide appropriate pricing signals for other investors in generation. ECNZ was also required to sell a greater proportion of its output under longer-term hedge contracts (declining from 87% one year ahead through to 30% five years out) as a means of diminishing its incentive and ability to affect wholesale electricity market prices, and also to ease the transition to the wholesale market (by reducing customers' exposure to spot price movements). All of these constraints were to persist unless and until ECNZ's market share fell to 45% or below.

### *June 1995 Memorandum of Understanding*

The details of these reforms were set out in a Memorandum of Understanding (MOU), between ECNZ and government, of 8 June 1995. That agreement also set out that ECNZ was to continue with its sale process of the land, consents and gas contracts required for a new gas-fired combined-cycle generation project planned for Taranaki. This sale occurred in 1996 to a consortium comprising Fletcher Challenge, Mercury Energy and Canadian TransAlta. The MOU went on to note that ECNZ was at that stage prohibited under its contract with government under the SOE Act 1986 (its Statement of Corporate Intent) from acquiring a significant share in any ESA (by then called an energy company). Importantly, it provided that this prohibition would also be lifted once ECNZ's market share fell below 45%.

As it happens, the 1995 reforms were a political compromise conditioned by ongoing ECNZ opposition to break-up on cost and risk grounds. More aggressive break-up options had been considered, but their time had not yet come. It was not until the then National government was returned to power with a coalition partner following the country’s first MMP elections in 1996 that further break-up was considered. Reflecting a combination of ongoing preference among officials for break-up, persisting tension between government and ECNZ, and reduced electricity prices following the creation of Contact, a review of break-up options was announced in June 1997. The result of that review was the announced separation of ECNZ into three separate and competing SOEs in a further reform package in April 1998, with effect from 1 April 1999.



Source: M-Co data (unpublished), ECNZ (1991), and CPI calculator at [www.rbnz.govt.nz](http://www.rbnz.govt.nz).

*ECNZ’s Final Separation, and the Birth of Vertically Integrated “Gentailers”*

With the creation of Meridian Energy, Genesis and Mighty River Power, as the new SOEs were to be called, all restrictions on generators that prevented them

from owning energy retailing operations were to be lifted. Since the 1998 package included the enforced separation of ownership of distribution businesses from that of competitive activities (such as generation and retailing), this reform resulted in a fundamental and unpredicted realignment of the industry. As the owners of combined distribution/retailing/generating companies scrambled to divest themselves of generation and retailing in favour of ongoing lines ownership, all generators scrambled to secure a retail customer base as a natural measure to hedge their exposure to wholesale market price volatility. The electricity sector, being comprised of multiple generators from the dismembered ECNZ as well as new entrants, quickly became vertically integrated between generation and retailing. In a move that was quite out of character for post-MMP governments, Contact was privatised in 1996, with a controlling stake being sold to US-based Mission Energy, but current policy is for the remaining state-owned generators to continue under government ownership.

As shown in Figure 5.3, the final separation of ECNZ in April 1999 resulted in an overnight and sizeable reduction in wholesale electricity prices, followed by a period of slightly increased price volatility. Given the subsequent upward trend in prices it might be surmised that this represented a transitional decline as the new generators became used to the dynamics of competition (and possibly learned how best to increase combined generator welfare by easing up on competition). However, it could also be attributed to ongoing demand growth and the resulting increase in the amount of time more expensive plant is required to meet that demand, or simply to hydrology and other fuel limitations.

Table 5.1 provides summary statistics for the average main-centre prices both before and immediately after the final separation of ECNZ. A fall in prices, but slight rise in price volatility, are clearly evident.

Measure	Christchurch		Wellington		Auckland	
	Pre 4/99	4/99 – 12/00	Pre 4/99	4/99 – 12/00	Pre 4/99	4/99 – 12/00
Mean	37	28	41	30	48	37
Median	37	26	41	29	48	35
Std. Deviation	13	13	13	14	15	18

Source: M-Co data (unpublished).

#### *Wholesale Market Prices versus ECNZ Predictions*

Figure 5.3 tells yet another interesting story, comparing actual wholesale electricity prices with predictions made in ECNZ (1991) as to prices that would need to prevail

to support future generation developments, based on long-run marginal costs.<sup>10</sup> In 1991 dollars, development based on gas-fired stations was predicted to require prices in the order of \$55-60/MWh, for coal-fired developments \$65-70/MWh, and for hydro development \$70-80/MWh. Median electricity prices even for Auckland have typically tracked well below these predicted levels, as have mean prices – despite being more sensitive to price spikes than median prices. Indeed, these wholesale prices compare with average prices charged by the then monopoly generator ECNZ for 1987 through to 1991 of between \$48 and \$55/MWh (\$61 to \$70/MWh adjusting for CPI movements between June 1991 and June 2004, or \$75 to \$86/MWh adjusting from June 1986 to June 2004).

In this light it can be concluded that NZEM prices have been significantly lower than those experienced under ECNZ, despite the need for new generation over the past decade. Certainly price volatility has increased with the shift from ECNZ's administratively determined prices to those determined under the NZEM, but this is to be expected with the former set under fixed-price contracts (subject to a \$150/MWh cap) and the latter having higher informational content (reflecting the expectations of multiple market players rather than those of ECNZ, and the better assessment of the marginal cost of water under the spot market price-discovery process). In any case average prices under the decentralised wholesale electricity market can be said, on the basis of this comparison, to have bettered those under the centralised pricing model employed in the early stages of New Zealand's electricity reforms.<sup>11</sup>

## DISTRIBUTION REFORM AND RE-REFORM

### *Anticipatory Reforms*

Under 1968 legislation the combined distributors/retailers, comprising locally controlled ESAs, required licenses to supply electricity or operate electric lines within defined geographical franchise areas. While these operators were permitted to supply electricity outside of their franchise areas, they could do so only with the consent of the licensed operator in that other area. In practice this did not result in competitive energy trading. While reform of generation and transmission quickly became part of the government's 1980s reform agenda, it was not until the early 1990s that reform extended to the ESAs.

An early move was to make ESAs subject to income tax with effect from April 1987. As noted above, the 1989 Electricity Industry Task Force endorsed previous government

<sup>10</sup> Such costs were defined to include capital costs amortised over the life of the generation plant, and operating, maintenance and fuel costs.

<sup>11</sup> Appendix 5.1 provides estimated wholesale electricity prices for 1978-2003 after attempting to adjust for some of the structural changes occurring over the period. Such changes make it difficult to measure price indexes measuring the same good or service over time.

moves to remove ESA franchise areas and supply obligations, and noted ESA moves in preparation for restructuring including corporatisation, the phasing out of cross-subsidies between residential, commercial and industrial customer classes, and a reduction in the number of ESAs by about 10. The 1990 legislation ended the appointments of elected ESA board members and required the appointment of commercial directors.

*Electricity Act 1992 and Energy Companies Act 1992*

The most fundamental reform of distribution and retailing came with the passage of the Electricity Act 1992 and Energy Companies Act 1992. Under the latter ESAs were corporatised along SOE-Act lines, and established as profit-motivated electricity companies (having regard to other objectives such as the desirability of encouraging energy efficiency). In forming such companies, decisions were required as to how they should be owned. The majority ended up under customer-trust (or consumer-trust) ownership. Franchise areas and supply obligations were incrementally removed, with small customers (less than 0.5 GWh/year) the first to be given an opportunity to change energy supplier, as they were expected to be most exposed to price increases with the removal of cross-subsidies. Large customers were opened up to competitive suppliers from 1 April 1994, in anticipation of which metering and reconciliation arrangements (MARIA) were agreed by industry. The distribution and retailing activities of the new electricity companies were to be ring-fenced on an accounting basis, and information disclosures used as the means to expose any misconduct by essentially non-competitive distribution (the so-called "light-handed" regulatory approach). Transitional price-control provisions were included but not applied for either distribution or retailing, and levies to fund subsidies for rural electricity users were phased out.

A process of rationalisation ensued, with a number of electricity companies being sold to private interests (such as local or foreign trade buyers, portfolio investors or via share listings) or merged. In order to facilitate competition in energy retailing, buying groups were formed or critical mass in customer numbers sought so that economies in energy purchasing could be translated into lower energy margins. Efficiencies were also sought in areas such as head office and maintenance costs in particular, although for reasons discussed below the incentives for such gains were heavily attenuated by the regulatory arrangements implemented for distribution activities. As shown in Chapter 3, the results of these reforms were not as positive as expected, with the removal of cross-subsidies from commercial customers to residential customers contributing to an overall increase in real residential electricity prices. While industrial and commercial users were enjoying the benefits of real price reductions from competition under the new arrangements, the promised reductions in residential electricity prices evolved, at the political level, into prices being subject to "strong and sustained downward pressure", which did not carry quite the same political appeal. Further reform loomed.

*“A Better Deal for Electricity Consumers”*

The April 1998 package, “A Better Deal for Electricity Consumers”, was enacted by the Electricity Industry Reform Act 1998 and sought to see reform benefiting residential customers (or that government be seen to be directing industry towards that end). Distribution operators were viewed as lacking incentives to achieve cost efficiencies, and as having incentives to deter competition in retailing (by not facilitating customer changeovers, restricting competitor access through their networks, or using monopoly rents from distribution to cross-subsidise retail customers at risk of switching to competitors) and to invest in uneconomic generation using profits from lines. The solution was to force the separation of ownership of lines activities from competitive activities (which were taken to include metering as well as retailing and generation) with effect from 1 April 1999. This move was backed with stiffened information-disclosure requirements and the threat of price regulation for distributors under then-latent provisions in the Commerce Act 1986. Industry was threatened with imposed measures if it did not rapidly develop effective means for small customers to switch energy suppliers.

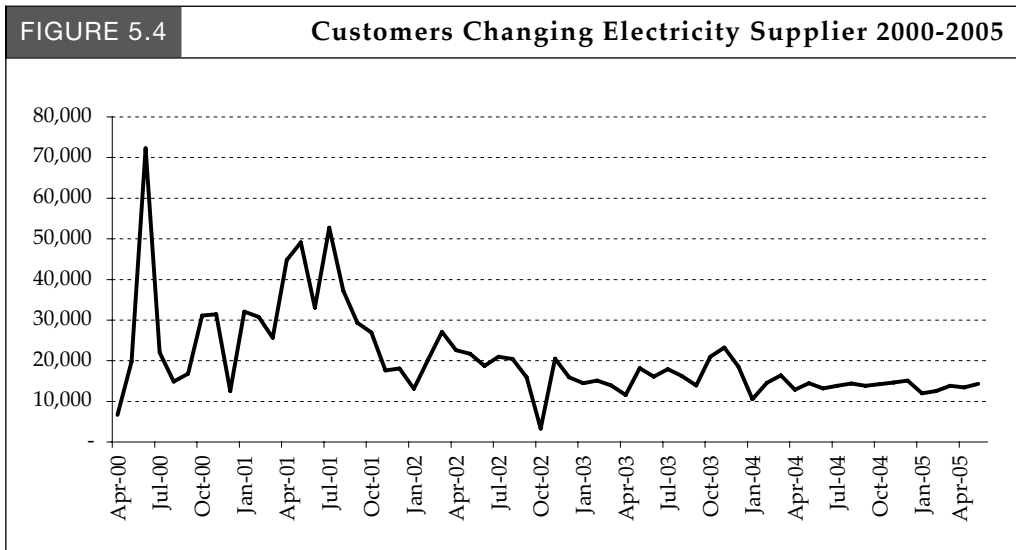
*Deemed Profiling and Customer Switching*

This last measure was taken because of arguments that the industry’s metering and reconciliation agreement (MARIA) imposed costs on new retailers that discouraged their competitive entry (acknowledging that these costs were greater than current retail margins). While falling metering costs were seen to predict ongoing uptake of time-of-use metering by successively smaller customer classes, this uptake was not likely in the near-term for residential customers. In accordance with the government’s requirements, industry instituted a system of “deemed profiling” on 1 April 1999 whereby the electricity-demand profiles of smaller un-metered customer classes were proxied on a statistical basis – not altogether unlike insurance companies allocating risk profiles to various customer classes. The mandated changes of 1999 required substantial investment by companies in new billing and reconciliation systems which, in association with increased “wheeling”, during a lively adjustment period threw up all sorts of anomalies and odd treatments of customers that received much publicity. However, as indicated by Figure 5.4, since April 2000 customer switching has become reasonably common, albeit uneven (including the spike in June 2000 when a registry backlog was cleared, and a surge in winter 2001 when NGC’s electricity customers were acquired by Genesis and Meridian).<sup>12</sup>

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<sup>12</sup> For reference purposes note that there are around 1.5 million residential customers, 125,000 commercial customers and 100,000 industrial customers, i.e. 1.725 million in total. Hence a monthly switching of 15,000 customers represents a monthly turnover of almost 1%.





Source: M-Co (2005).

### *Retail Margins and Competition*

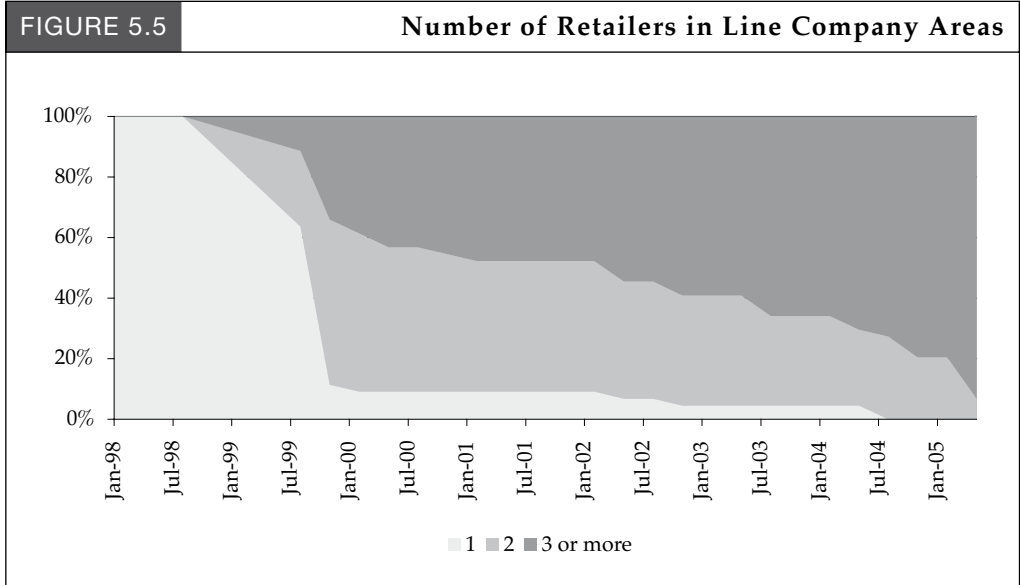
Whether or not such switching has been effective in reducing retail energy margins for smaller consumers remains a moot point. An investigation by the Ministry of Economic Development (MED) reported in January 2004; it suggested that the margin between retail and estimated wholesale prices had been climbing, but that the trend was now possibly broken. As shown by Figure 5.5, since deemed profiling was introduced there has been a steady increase in the number of retailers in each distribution area. While 78% of customers were supplied by incumbent retailers as at June 2003, and 55% by volume of electricity is sold by incumbent retailers, these figures are significantly better than in some other countries.<sup>13</sup> The MED concludes that there is evidence that competition is increasing. Certainly the contestability of small retail customers (i.e. the prospect of alternative energy suppliers seeking to offer or offering an alternative should incumbents enjoy excessive margins), if not outright and aggressive competition, would appear to have developed.

Hutton (2004) finds that though retail margins rose significantly during 1997-2001, they declined rapidly over 2001-2003.<sup>14</sup> In other words, retail margins have varied widely since the introduction of the NZEM, because wholesale prices are much more volatile than retail prices and because retail price adjustments tend to lag behind wholesale price changes. Retailers bear the brunt of wholesale price changes, so rapidly rising retail margins in the short term are not necessarily evidence of any sort of market non-performance as they

<sup>13</sup> Early evidence from reforms in Germany, for example, was that only 2% of customers switched energy supplier. See Glachant and Finon (2003).

<sup>14</sup> Like the MED, Hutton notes the difficulties in estimating retail margins due to the complexity in reliably estimating wholesale prices, particularly with changing market arrangements over time.

may derive from falling wholesale prices rather than rising retail prices. The effect of wholesale price swings on retail margins means that it is difficult to reliably discern any effect on retail margins from customer switching over such a short time period.



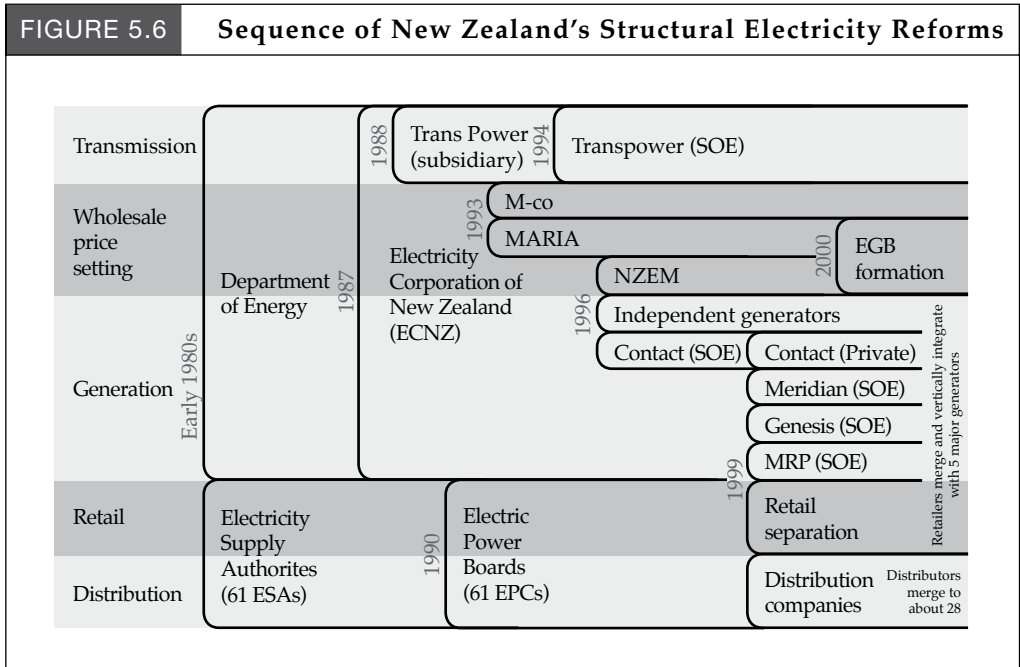
Source: Ministry of Economic Development (unpublished).

The course of New Zealand’s contemporary electricity sector structural reforms, culminating in the break-up of the energy retailing and lines operations of distribution companies and the subsequent formation of vertically integrated gentailers, is summarised in Figure 5.6.

**REGULATION AND RE-REGULATION**

*Birth of Light-Handed Regulation*

Since the passage of the Commerce Act in 1986, replacing industry-specific regulation with general competition rules to be applied across sectors, so-called “light-handed” regulation has been the presumptive approach in New Zealand. Reinforced by the threat of more direct and heavy-handed regulation through provisions in the Commerce Act that until recently have remained latent, this approach relied on information disclosures, and monitoring and the corrective power of both affected parties (and ultimately government) to keep undesirable behaviours in check. This approach was given expression in the Electricity Act 1992 in the form of provisions allowing regulations to be issued mandating a range of information disclosures from lines companies in particular (but also generators and ECNZ), with transitional price controls also possible for both lines and/or energy retailing until 1 April 1997.



Source: Robertson *et al.* (2003).

These provisions took shape with information disclosure regulations being promulgated in 1994, administered by the Ministry of Commerce, mandating the disclosure of various efficiency and financial performance measures. Following the model developed for Transpower in 1992, the financial performance indicators included the so-called Accounting Rate of Profit (ARP)<sup>15</sup>, being the financial rate of return earned by lines operators on their lines, and the Optimised Deprival Value (ODV). The latter measured the current replacement value of lines assets based only on an assumed necessary configuration of system assets and given existing asset ages and lives (the optimised depreciated replacement cost, or ODRC), or the present value of the income expected to be earned on those assets (the economic value, or EV) if lower.<sup>16</sup> Thus ODV was the lesser of ODRC or EV. The ARP was a measure of the rate of return on ODV from lines operation which could be directly compared to a “fair” rate of return given expected returns on investments of comparable risk, typically taken to mean an appropriate Weighted Average Cost of Capital (WACC) as commonly used by financial practitioners. Thus changes in ODV would influence the value of ARP, and hence of any assessment of whether excess returns were being earned from lines operations when compared with WACC.<sup>17</sup>

<sup>15</sup> Later refined and renamed the Return on Investment (ROI).

<sup>16</sup> Stranded assets were treated separately, being valued at net realisable value and excluded from ODV.

<sup>17</sup> Which itself affects the economic value (EV).

*ODV Rules*

A number of practical difficulties arose with the implementation of the disclosure rules, including inconsistencies and unintended applications of the ODV rules. For example, different lines operators applied differing optimisation rules, certain costs only indirectly associated with lines operations were treated as being so associated by some operators but not others, and significant variations arose in asset lives and other assumptions used in calculating ODVs. The June 1998 reform package discussed above included measures designed to increase the consistency and transparency of disclosed performance measures, and required additional disclosures such as lines operators' asset management plans (highly topical in the light of the 1998 Auckland CBD power crisis discussed in Chapter 6) so that more comprehensive assessments could be made of whether operators were trading off operating standards and system longevity against profitability.

More fundamentally, however, the ODV-based disclosure regime, like rate-of-return regulation, created only weak incentives for lines operators to make efficiency gains, perhaps as the cost of avoiding the distortions possible under more heavy-handed approaches.<sup>18</sup> The difficulty for a lines operator under the scheme was that it would face opprobrium or other sanctions (if at all) only if its ARP rose significantly above its estimated WACC. A simple way to avoid breaching such a threshold was to be inefficient, which would then permit high lines charges without excess returns being revealed. Another way would be to load as many indirect costs into ARP calculations as could be tolerated, or maximise the use of ODV-inflating assumptions.

Alternatively, a lines operator committed to securing efficiencies would enjoy the benefits of doing so only if their initial ARP was less than WACC, and then only until their ARP rose to WACC. Once that threshold was reached, any further efficiency gains would be to the benefit of consumers in the form of lower prices (or suppliers in the form of inflating costs) but not to the lines operator and its owners. Similarly, an efficient lines operator might aggressively value its system assets on the lean side, thereby minimising its ODV, but this might then land it in a situation of having to reduce perhaps already lean lines charges to avoid their ARP exceeding WACC. In short, the focus was less on disparities in lines charges – which disparities could be expected to be quite large given widely differing network characteristics resulting from widely differing geology, topography, and nature and density of customers – than on the net returns earned by lines operators, which net returns could be derived by either desirable or undesirable means.

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<sup>18</sup> Arguably stronger incentives for efficiency gains were achieved where lines companies were owned by customer trusts – since those bearing the costs of inefficiencies had incentives to see them removed – although governance issues with such trusts served to diminish this advantage (see Chapter 9).

*June 2000 Electricity Industry Inquiry*

A distinctive shift in approach to distribution-business regulation arose following an inquiry into the electricity industry commissioned by the Labour/Alliance coalition government formed after the 1999 general election. Announced in February 2000, the inquiry was to evaluate – without indicating why an evaluation was necessary – whether current regulatory arrangements met government's objective of ensuring that "electricity is delivered in an efficient, reliable and environmentally sustainable manner". Where arrangements were found to be deficient, it was to recommend changes. Reporting in June 2000, the inquiry concluded that the threat of price regulation was not considered credible by lines operators, so, in addition to refinements to the disclosure regime, it recommended that the Commerce Commission take over the administration of the regime and set about defining thresholds beyond which lines operators would face direct price controls.

*Shift to Heavy Regulation*

Certain of the Electricity Industry Inquiry's recommendations were implemented via the Commerce Amendment Act 2001 and Commerce Amendment (No. 2) Act 2001. Under these amendments, the latent price controls in Part IV of the Commerce Act 1986 were replaced by specific powers for the Minister of Commerce to impose controls (on prices, revenues or quality standards) for controlled goods, for the Commerce Commission to develop thresholds for the application of controls, and for controls to be targeted at specific operators (rather than entire industries as previously) for periods of up to five years. The latter (No.2) Act went on to require all lines operators to submit revised ODV valuations subject to the Commission's approval; it also required the Commission to review the ODV methodology. After lengthy consultation the Commission promulgated its thresholds in December 2003, with the result that lines operators (including Transpower) are now subject to CPI-X price regulation of varying degrees depending on operator classes defined by reference to efficiency and other measures, and thresholds for review. Given expected inflation, these controls are unlikely to result in significant changes in lines charges – certainly not anywhere as large as those imposed in England and Wales – even for operators deemed to be in the least-efficient category, and some more-efficient operators will even be permitted to increase lines charges (since both their charges and rates of return are low). The controls carry no distinction on grounds of lines-company ownership, thus ignoring the beneficial effects of customer ownership in mitigating overcharging by monopoly lines companies (see Meade (2005)).

**"A FAIR DEAL FOR ELECTRICITY CONSUMERS"**

More generally the June 2000 Inquiry heralded a significant expansion of the scope of government's direct involvement in the operation of the electricity sector. The new government expressed its approach as being to use "industry solutions where

possible and regulatory solutions where necessary". While this of itself did not signal a material departure from the approach taken previously, the scope (and in some cases the nature) of the changes required of industry was such that industry-level solutions were unlikely to be feasible in the timeframes allowed (if at all). Accordingly, a package of reforms was announced by government in response to the 2000 Inquiry, released in October that year and described as "A Fair Deal for Electricity Consumers". This package amounted to an effective shift towards more widespread and direct government control of the industry, not confined to policy-setting or to areas facing competition issues or concerns about market power, and increasingly directed towards environmental and equity goals. A critical element of the package was an industry-wide, centralised planning and administration governance structure that government would impose by legislation if the industry could or would not deliver it. In large part because of the breadth of the governance structure and unresolved issues about the treatment of long-term contracts, industry did not agree on a governance structure and so government legislated for it.<sup>19</sup>

## CURRENT AGENDAS

### *Rapid Industry Centralisation – The Electricity Commission*

Following the October 2000 reform package, relevant legislation passed by government includes the Electricity Amendment Act 2000, Electricity Amendment Act 2001, Electricity Industry Reform Amendment Act 2001, Commerce Amendment Act 2001, Commerce Amendment (No. 2) Act 2001, and Commerce Amendment Act 2003. Industry governance was from 1 March 2004 consolidated under, and industry authority transferred from industry to, a new Electricity Commission (see Chapter 8). To address occasional winter power crises the Commission has contracted for reserve generation capacity and interruptible load (see Chapter 6), although this capacity is already being used as peaking plant. Among many other things (see Chapter 8 for a summary of the Electricity Amendment Act 2001), regulations are now in train to require distribution companies to offer low fixed tariff options to small customers, and consumer or customer trusts owning lines operations are to provide greater financial transparency to their beneficiaries. General consumer-law protections have now been

<sup>19</sup> One significant roadblock to the proposed arrangements was a requirement for compulsory membership of the NZEM which would then be a gross pool. Another was the preclusion of bilateral trading (which would then be allowed by means of CFDs only) and the subjecting of all trades to market rules to which bilateral trades hitherto had not been subjected (which some market participants clearly preferred, given 20% of energy was traded outside of the NZEM). Yet another was the treatment of long-term supply contracts with aluminium smelter operator NZAS which had been entered into long before the electricity reforms and which were inconsistent with proposed arrangements. This presented an issue that market participants would naturally struggle to resolve under compulsory arrangements that applied across the industry. The Electricity Industry Inquiry seemed to reflect an agenda of increasing centralisation of industry control under government, irrespective of the merits of the case.

extended to cover electricity and lines operation. The Electricity Commission can now prescribe reasonable terms and conditions for grid connection, regulate grid expansions or upgrades and allocate their costs, set grid quality and security standards, and set grid pricing policy.

**BOX 5.4****June 2000 Report of the Electricity Industry Inquiry ...****Regulation and Governance:**

- 1) Framework should reflect interconnectedness of industry.
- 2) Focus on principles and process, avoiding prescriptive approach.
- 3) Push decision-making as close as possible to those with knowledge, capacity and accountability.
- 4) Governance of wholesale market should be strengthened and membership compulsory.
- 5) Wholesale market should be overseen by body independent of industry, and take views of all participants into account.

**Wholesale:**

- 1) Governance bodies (NZEM, MARIA, MACQS<sup>20</sup>) should be replaced with single structure with compulsory membership and board elected by participants but comprising majority of members independent of industry.
- 2) New market structure should cover existing NZEM activities, but be expanded to include transmission and distribution pricing.
- 3) Government should invite industry to develop the proposed new governance structure within 12 months, and legislate for regulatory powers to achieve its development if industry fails to do so.
- 4) A real-time market should be implemented, and the development of financial transmission rights (FTRs) supported.
- 5) System operator should publish short- and medium-term system adequacy projections, and wholesale market bidding information should be disclosed within one month or sooner of relevant trading periods.

*box continues ...*

<sup>20</sup> Multilateral Agreement on Common Quality Standards – an industry governance structure created in 1999 to shift the determination of quality and supply security matters from Transpower to industry.

**Transmission:**

- 1) Transpower's principal objective to be achieved "in partnership with the government", striking a "reasonable and transparent balance" between earning a commercial return and achieving government's overall energy policy goals.
- 2) Transmission services to be contestable wherever possible, and to meet minimum standards but also to be agreed between Transpower and users.
- 3) Transpower's services to be priced according to government principles and market-determined methodology, developed under the the new industry governance structure.
- 4) Transpower to seek "optimum trade-off" between minimising maintenance costs and transmission losses.
- 5) New and replacement grid investments to be undertaken by Transpower and priced to encourage users with strong incentives to identify least-cost options (including energy efficiency and demand management), with investment costs to be recovered by market-determined methodology.
- 6) Market to be encouraged to bring forward distributed generation and demand-side solutions to relieve grid constraints, with transmission savings to be passed to distributed generators.

**Distribution:**

- 1) Commerce Commission should assume responsibility for information disclosure regulation and enforcement, and have distribution and transmission assets valued on a common basis.
- 2) Contracting arrangements between Transpower and government (statements of corporate intent, SCIs) to be replicated between distribution companies and their owners where controlled by trusts or local bodies.
- 3) Commerce Act should be amended to empower Commerce Commission to impose targeted (i.e. company-specific, rather than universal) price controls (including CPI-X) on lines operators, and to set thresholds for their imposition.
- 4) Distribution companies should be allowed to invest in distributed generation (i.e. despite 1998 separation).



## BOX 5.4 CONT'D

## ... June 2000 Report of the Electricity Industry Inquiry

**Retail:**

- 1) New industry governance body to further develop and enforce customer switching protocols (or government to regulate if body's protocols ineffective).
- 2) Industry should develop ombudsman scheme to apply to distribution and retail within six months, or government will look at other implementation options.
- 3) Amendment to Consumer Guarantees Act 1993 extending its coverage to electricity is supported.
- 4) Where retailers become insolvent, customers should become attached and liable to incumbent retailers (with their electricity cost set at the wholesale price).
- 5) Retail companies should be obliged to offer pre-payment meters at reasonable cost.

**Energy Efficiency/Sustainability and the Environment:**

- 1) Fixed network charges should account for less than 25% of household electricity bills, with the Energy Efficiency and Conservation Authority (EECA) to monitor and report breaches to the Commerce Commission.
- 2) Transmission charges should be amended to allow co-generation owners to trade off standby reliability and its price.

Source: Inquiry into the Electricity Industry (2000).

*Distributed Generation Encouraged*

Consistent with its overall objective of ensuring that "electricity is delivered in an efficient, fair, reliable and environmentally sustainable manner to all classes of consumer", the government has also taken steps to encourage greater investment in distributed generation, particularly that based on renewable energy sources. Indeed, under the Electricity Industry Reform Amendment Act 2001 it has relaxed restrictions following the 1998 ownership separation reforms on lines companies also engaging in generation provided they do so with renewables, and the Electricity Amendment Act 2001 provides for regulations to facilitate the interconnection of distributed generation to distribution networks. Investments in distributed generation, locating generation closer to demand and avoiding the transmission grid, are intended to mitigate problems of grid constraints (including line losses and market power) thereby reducing electricity prices, deferring the need for grid expansion, helping to meet environmental objectives, increasing generator competition within regions, making generation investments more affordable (compared with more capital-intensive large-scale generation) and enhancing system security. It is interesting to note that such

moves represent a reversion of sorts to the situation existing in New Zealand prior to construction of the grid and state monopolisation of generation.

### *Rapidly Expanding Regulatory Powers*

The Electricity and Gas Industries Bill 2003, enacted in October 2004, amends features of the 2001 legislation, as well as materially expanding the regulatory scope of the Electricity Commission. Under the legislation, generators can be required to make a minimum level of their capacity available via supply or other hedge contracts, and wholesale electricity buyers can be required to carry a minimum level of hedge cover. The Commission's roles will potentially extend well beyond industry governance to the level of industry micro-management, albeit of companies with significant private or non-government ownership. The operational independence of state-owned generators and Transpower will also now be further eroded in favour of the Commission.

## CONCLUSION

Reform of electricity sectors worldwide present us with a possible “chicken and egg” conundrum. While changes in attitude towards state or otherwise centrally controlled electricity systems resulted in a reassessment of those parts of such systems that might be usefully opened up to competition and which must remain tamed monopolies, it is possible that such changes were more a reflection of ideology and fiscal imperative than a moment of inspiration. In countries where such motivations were present, early and radical reform has been possible. In countries where they were not, the experiences of early reformers have possibly been the greater influence, simply by demonstrating what was achievable (and what pitfalls to avoid) and begging the question, why not? The issue then became the pace and extent of reforms, rather than their fact or nature. The question New Zealand now faces is whether to proceed along lines consistent with its earlier reforms and the reforms elsewhere, or to adopt a course that involves reversionary and more idiosyncratic elements.

New Zealand was among the first states to reform their electricity systems along more market-oriented lines. In the mid 1980s, it could have been said to be rapidly pursuing elements of reforms adopted elsewhere, such as the unbundling of transmission and generation, but in fact it has remained decidedly behind the pack in terms of both privatisation and decentralisation. Despite common misperceptions, most of the New Zealand electricity sector remains in government ownership, and increasingly is reverting to centralised government control – despite the intent of corporatisation under the SOE Act. New Zealand persists with a centralised wholesale electricity market (in fact more so with the move to a gross pool in 2004), despite the growing preference internationally for decentralised bilateral trading and the use of power exchanges for contract trading. As discussed in Chapter 7, this is also likely to forestall

improvements in demand-side participation, for smaller customers at least, which would help to mitigate any concerns about persistent market power in generation (see Chapter 9).

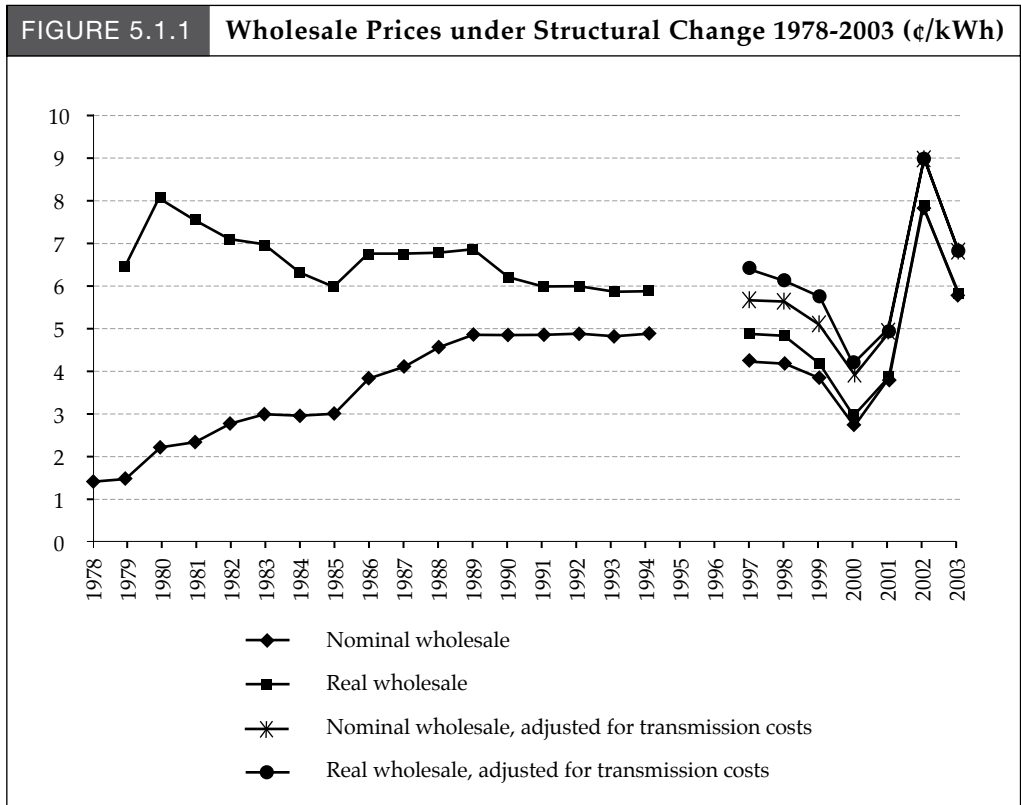
Transmission reform has remained stalled and, as discussed in Chapters 8 and 10, represents a telling weak point in the overall reform process. The assumption of transmission pricing and investment responsibilities by the new Electricity Commission shifts these critical problems sideways, and it remains to be seen whether this shift produces sufficient benefits to overcome the additional problems it generates. The contemporary reversion towards centralised industry control under government ownership is supposedly intended to overcome the real or perceived problems that confronted the industry under its semi-liberalised arrangements. Yet it represents a course at odds with trends elsewhere, and threatens the viability of private participation in the sector. This has the potential to crowd out private solutions to issues confronting the sector and to thereby hasten a full reversion to the pre-reform arrangements.

That New Zealand has now opted for heavy-handed regulation as well as predominantly central government (or local/community) ownership suggests that we have ended up with an overly restrictive framework, since other countries have achieved the pricing gains and anti-monopoly protections that New Zealand now seeks while at the same time securing very significant proceeds and decentralisation benefits from asset sales. Indeed, New Zealand taxpayers, as owners of state-owned generators and transmission, continue to underwrite the significant risks of future industry investments.

Of greater import is New Zealand's move towards greater re-centralisation of governance and operational control of both state- and privately-owned operations in the reformed sector. Representing a reversion towards the model existing prior to the reforms in New Zealand and elsewhere, this trend is counter to that continuing elsewhere – including the late-starting and sometimes reluctant European Union – except in the failed reforming state of California (whose misfortunes New Zealand has not shared). It remains to be seen whether this will encourage or discourage ongoing private-sector participation in the sector and contribution to its ongoing development, or whether New Zealand will revert to a pattern observed in the sector's earliest years where local and regional development is substituted for larger-scale national solutions, or national solutions are implemented but only with a reversion to a centralised and administrative approach, with the cost and risk of industry development being borne by taxpayers and consumers but the control of such development likely to reside elsewhere.

APPENDIX 5.1 – WHOLESALE PRICES UNDER STRUCTURAL CHANGE

Prior to 1993, all costs of transmission were borne by ECNZ (and its government-run predecessors) and so were factored into the wholesale price, along with generation costs. Electricity supply authorities would then purchase electricity from wholesalers at this price and add a margin to reflect distribution and retailing costs, which would be reflected in the final retail cost.



Source: NZED, ECNZ, Ministry of Commerce, and NZEM for wholesale prices; Transpower for transmission cost adjustment.

Notes: Prior to 1995 average prices are calculated by total revenue/units sold. Post 1997 the prices are from the Haywards reference node price, as total revenue is not available. Distribution transmission cost data are unavailable prior to 1997.

After 1993, transmission costs were split between generators and distributors – distributors and major energy users were required to pay a connection fee for grid access. This means that the wholesale cost would represent the cost of generation, but only part of the cost of transmission rather than the entire cost of transmission. Thus,

all else being equal, we would expect the wholesale price to fall, because it no longer includes most transmission costs. The retailers would then add a margin to cover retailing and distribution costs, including those transmission costs borne by distributors.

In other words, a naïve time series of wholesale prices would not be measuring the same thing over time, and so might falsely suggest that wholesale prices had fallen when in fact there had been no change of economic significance.

A better method is to adjust for the transmission cost adjustment by adding back the cost of transmission borne by distributors, and so to generate a consistent time series. Doing this yields the price series in Figure 5.1.1. The volatility since 2000 reflects the effect on retail margins of wholesale price volatility.



*In this chapter we examine New Zealand's historical experience with supply insecurity and how such insecurities were managed under the centralised, engineering-based model of electricity provision. We then contrast that experience with the experience arising post the reforms. First we consider the 1992 winter power "crisis". We use the term "crisis" guardedly since the contemporary experience has been far kinder than that in previous decades. In 1992 electricity provision was still largely centralised under ECNZ, but with a clear commercial focus and a modified set of operating constraints. We then consider the 2001 winter power "crisis" and what we will call the 2003 winter power "scare". Whereas the 1992 events provide a contrast between pre- and post-reform experiences, the 2001 and 2003 events provide contrasts with that in 1992 because of the advent of the NZEM. To provide yet another point of contrast we discuss the transmission outage of February 2004, since the ongoing centralisation of grid operation and investment represents an enduring counter-example to the reforms instituted elsewhere in the sector, notably the decentralisation of generation. For completeness we also discuss the 1998 Auckland CBD outage, although it appears to be an outlier, rather than an insight into the reforms. With these events in mind, we then examine the role of spiking wholesale power prices in winter power "crises", arguing that such spikes are not only necessary but desirable. New Zealand's recent reserve generation scheme is then reconsidered, given that it necessarily places constraints on the rationing role of wholesale electricity prices.*

## ELECTRICITY SYSTEMS VULNERABLE TO SHOCKS AND CRISES

### *Overseas Events*

All electricity systems are vulnerable to and experience shocks and crises. On 14 August 2003 the north-eastern US and parts of Canada suffered a spectacular outage plunging New York, among other major cities, into darkness for a day. Just two weeks later, human error led to a transmission fault stranding London commuters and cutting power to hundreds of thousands, for hours in some cases. Soon after, nearly 4 million Danes and Swedes lost power for an afternoon; and in a separate incident that month, 50 million Italian electricity consumers were deprived of power for a day when transmission lines from Switzerland sagged and touched a tree. During the summer of 1998 in the US midwest, generation capacity shortages combined with high temperatures to result in major electricity price rises – peaking at US\$7,500/MWh – although blackouts were avoided. These dramatic events were experienced both in countries with reformed electricity systems (e.g. England), and those yet to

institute major reform (e.g. Italy). In the main they arose from transmission failures, but tight supply conditions were also a cause.<sup>1</sup>

### *Fuel Risks and the Weather*

At a more basic level, electricity systems dependent on generation using fuel oil or gas are vulnerable to escalations in the price of oil (e.g. oil price shocks), sudden falls in supply (e.g. wars in the Middle East), gradual falls in supply (e.g. fossil fuel depletion), the vagaries of fuel exploration, and emissions taxes. Systems dependent on coal can be similarly exposed – and to other risks besides, such as industrial disputes. Other risks to any electricity system include extreme weather events or simply the weather itself. Not only can the weather affect generation reserves where hydro power is used, but it also drives seasonal demand patterns and creates peak loads – whether for heating in winter or cooling in summer – that have the capacity to stretch each link in the electricity system’s chain to its limits. At the same time, electricity consumers are increasingly vulnerable to insecurities in electricity supply, with much of modern working and living having become electricity-dependent, not least the information and communications technologies now pervasive in industrial and even less-developed countries.

### *Changing Balance of Supply and Demand*

In general terms, the single greatest driver of instability in an electricity system is that caused by the changing balance between supply and demand. If demand can be guaranteed to be within the supply capability of an electricity system at all times, then the chance of system failure is limited to drivers largely determined outside of that system. However, forecasting future electricity demand even in the short term is notoriously difficult, and in the longer-term prone to significant error.<sup>2</sup> The history of electricity systems is typically one of supply doing its best to keep ahead of an ever-growing demand, often with temporary periods of surplus as a result of the costly and “lumpy” nature of system expansion. Little regard has been had to the relative desirability of new demands, which are distorted when electricity prices are determined administratively rather than via decentralised market-based mechanisms. Supply security – where it has arisen – has typically required consumers or taxpayers to carry the cost of maintaining surplus system capacity. Where this excess capacity has not arisen, electricity systems must be run close to their technical operating limits, emphasising the trade-off between system security and available capacity.

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<sup>1</sup> The Californian crisis of 2000 discussed in Chapter 4 is an example where few would doubt the greatly exacerbating role played by faulty electricity-sector reforms and regulation. The root of the crisis, however, lay elsewhere, with a hotter-than-usual summer and dryer-than-normal year (reducing hydro inflows), strong economic growth feeding into increased electricity demand, and sharp increases in gas costs and the price of pollution permits.

<sup>2</sup> Galvin (1985) assessed the historical record of electricity planning in New Zealand, reporting over-estimates of demand growth, that ranged between 33% and 51% for the periods considered.



### *Systemic Risks*

More specifically, by their very nature interconnected electricity systems suffer the additional risk that failures or constraints in one part of the system may affect the operation of the rest of that system. In the case of failures, additional failures can be triggered elsewhere (the famous “cascade” effect so dramatically observed in the north-eastern United States and parts of Canada in August 2003, and in Italy soon thereafter). In either case other parts of the system can be required to take up any resulting slack, such as alternative transmission paths or generation being required when transmission constraints bite.

## NEW ZEALAND’S VULNERABILITIES AND RESPONSES – BEFORE CONTEMPORARY REFORMS

### *Early Twentieth Century*

In the early part of the twentieth century, New Zealand’s electricity system was characterised by generation development leading to the creation of new energy demands that quickly outpaced supply. As such, the system – or in those days, more commonly, geographically distinct systems – suffered from an exposure to climatic conditions affecting demand, accentuated because most generation was hydro-based. More fundamentally, though, such systems risked being run at their technical limits, if only at times of peak demand, and had limited ability to call upon other parts of the system to compensate for any shortfalls or failures.

### *1940s and 1950s*

It was during the course of the 1940s and 1950s that New Zealand’s exposure to weather conditions – particularly as they affected available hydro storage – became a key challenge to the security of the then national electricity supply. Over the 1950s it was not uncommon for consumers to face supply cuts of 10-30% at various times of year, depending on where they lived, as a consequence of drought. Over the war years, in particular, adverse climatic conditions resulted in a wide range of measures to curb or otherwise control energy consumption so as to ensure security of ongoing supply, including public campaigns to reduce demand, load regulation by supply authorities, cuts to radio broadcasts, and the requiring of permits for (or in some cases prohibition of the use of) certain electrical appliances. Some price-based incentives were also used to encourage conservation, with examples of metering being installed and hourly electricity prices charged, but in the main restrictions and cuts were imposed on consumers where calls for voluntary savings were unsuccessful.

*1960s and 1970s*

The 1960s witnessed a favourable shift in the overall supply balance, particularly with new generation commissioned in the North Island, but the 1970s saw a return to supply shortages. Added to the previous problem of low hydro inflows into storage lakes were the oil price shocks (and embargo) of the 1970s, growing transmission constraints affecting regional demand/supply balances, and general demand growth requiring new generation capacity.

Once again government made calls for voluntary reductions backed up with threatened and actual cuts. Television broadcasting hours were sometimes reduced, hot-water cuts were applied where supply authorities had installed ripple control in domestic hot-water systems, and from July through to September 1973 blackouts were common 6:30-7:30pm weeknights, and early afternoon on weekends. Rolling blackouts were another tool used in the 1970s to manage supply shortages, and generation capacity reliant on oil was in some cases converted to cheaper or more secure fuels (e.g. based on newly developed indigenous gas supplies).

*1980s*

Water-heating cuts of up to 12 hours a day were required during the 1980s at the worst of the supply squeezes (arising from volatility in hydro inflows to storage lakes). In the main, however, New Zealand in these years – as in the 1960s – enjoyed a relatively secure electricity supply, even if it resulted from costly excess capacity.

NEW ZEALAND'S "CRISES" AND RESPONSES  
– AFTER CONTEMPORARY REFORMS

*Earlier Lessons Forgotten*

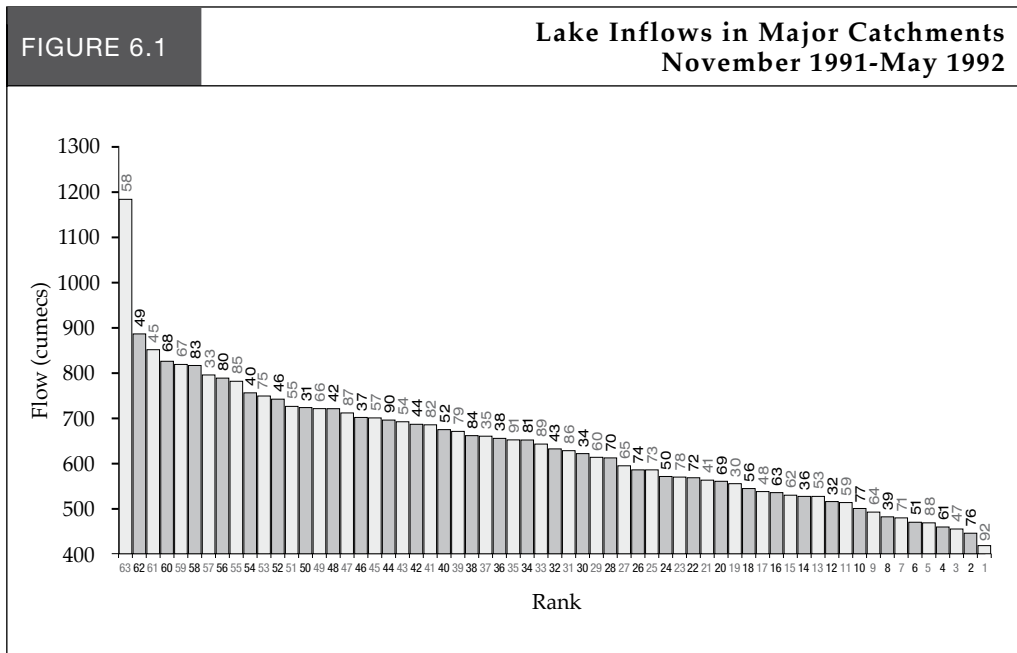
Supply crises in the years leading up to the contemporary electricity reforms – and the often-times draconian responses they spawned – appear to have been all-too-quickly and easily forgotten. With the first of two post-reform winter crises occurring in 1992 – the other in 2001 – the general discussion surrounding supply insecurity has often levelled blame at the structural and institutional arrangements arising under the reforms. Such attitudes have only been hardened in many quarters by the operation of a new device to alleviate supply shortages under the reforms – the wholesale electricity market that commenced full operations in October 1996. Calls are frequently made for government to intervene where the market is seen as having failed or been faulty, particularly where wholesale electricity prices have sky-rocketed and segments of the electricity sector have actually or seemingly reaped handsome profits during the crises. At times, some even call for an actual or effective return to “the good old days”.

Since winter 1992, however, electricity reforms of various colours and intensity have continued with much the same thrust as their predecessors. But an abortive winter crisis in 2003 on the back of political impatience with the 2001 crisis coincided with moves by government to intervene where previously industry had been charged with finding the necessary solutions. The future of the market has been publicly threatened by government.<sup>3</sup>

### 1992 Winter Crisis

The 1992 winter power supply crisis arose after the corporatisation of state-owned monopoly generation and transmission, but before the corporatisation and deregulation of distribution and retailing, and also before advent of the wholesale electricity market. It provides a useful counterpoint not only against the pre-reform period, but also against later reforms, in particular the creation of a wholesale electricity market.

At this time generation – centrally planned and administered by the state-owned generator Electricity Corporation of New Zealand (ECNZ) – comprised 75% hydro (and hydro storage, when full, accounted for around only 12% of annual demand), and inflows remained characteristically volatile. What precipitated the 1992 crisis was an unusual succession of lower-than-normal inflows – with key hydro lakes from November 1991 through to May 1992 experiencing their lowest (or second lowest) inflows in 62 to 67 years, as illustrated in Figure 6.1.



Source: Electricity Shortage Review Committee (1992).

<sup>3</sup> "Electricity Market's Survival linked to Crisis warns Government", *New Zealand Herald*, 9 April 2003.

The shortage was exacerbated by an unexpected increase in electricity demand, and by ECNZ operating to a supply security standard that could cope with the lowest inflows observed over a 20-year period (a standard it had inherited from its public-sector predecessor, the Electricity Division of the Ministry of Energy). A consequence of that standard was that ECNZ had available, or ran, thermal generation in the lead-up to and during the 1992 winter at a level less than that required to conserve scarce hydro reserves. While it had certain supply security obligations under its supply contracts with the then 48 ESAs (which distributed energy to end customers) and a handful of direct supply customers, ECNZ was under no statutory obligation to ensure a secure electricity supply; this is a situation which pertained in the past and continues with generators today.<sup>4</sup>

### *Sea-Change in Response*

The 1992 crisis witnessed a sea-change in terms of response. In May, ECNZ issued a press release advising of the drought conditions, the impact they were having on hydro reserves, and what measures it was taking to alleviate the problem. Soon afterwards industry representatives including ECNZ (which then included transmission), ESAs and other major electricity users – not government – took the initiative to coordinate industry’s response. Following discussions with government they opted against the time-honoured approach of compulsory rationing, considering it to be inequitable, and chose instead to make greater provision for consumers to make their own price/security trade-offs. Already the reforms had attenuated political involvement in the industry, and focus had shifted to the needs of electricity consumers.

The resulting response continued to involve public campaigns to reduce consumption – seeking voluntary cuts of 10% over May through to August, and achieving 15-20% savings. Government departments were directed to make savings of 10%. Other measures involved ECNZ negotiations with NZAS (a major direct-supply customer representing 15% of annual electricity consumption) to shut down one of its three aluminium smelter pot-lines, increased thermal generation, and at times cuts to water heating of up to 18 hours per day.

### *Role of the Fledgling Wholesale Market*

The bulk of energy supplied in 1992 was via direct contracts between ECNZ and ESAs or direct supply customers, specifying prices and, within ranges, supply quantities. While no formal wholesale electricity market was in operation, ECNZ posted half-hourly “spot” prices weekly in advance at which such customers could buy any additional

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<sup>4</sup> As noted in Chapter 8, under the Electricity Act 1968 the Ministry of Energy was (among other things) required to undertake “a continuous programme of works providing adequate supplies of electricity”, which is not the same as an obligation to provide uninterrupted supply at any price. Even now, with the new Electricity Commission being charged with ensuring New Zealand’s supply security, there remains no guarantee that all electricity demand will be met at any price regardless of hydrology or other factors affecting the balance of electricity supply and demand.

energy not covered by their contracts (or sell surplus energy back to ECNZ). Although capped at the cost of ECNZ's most expensive generation – at \$150/MWh – these spot prices rose over the course of the crisis, both signalling the growing scarcity of hydro reserves and providing some encouragement for consumers to conserve.

However, the result of the energy savings made during the winter crisis resulted in ESAs enjoying a windfall gain of \$57 million by selling energy arising from these savings back to ECNZ at the elevated spot price. With only one ESA passing this price signal back to end customers, it should come as no surprise that ECNZ's "spot" electricity market – a precursor to the current wholesale electricity market – had little success in influencing a demand-side response to the crisis. Nor could it have been expected to adequately signal ongoing needs for new generation capacity, or of itself provide any incentive for required generation investment.

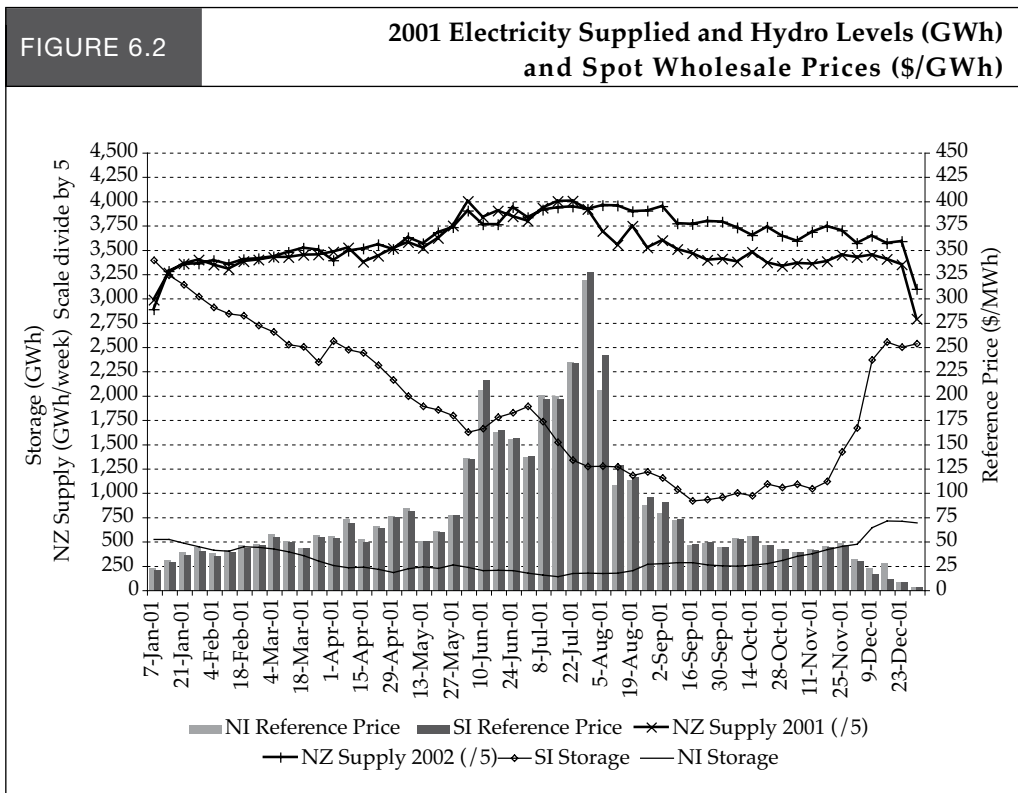
The report of the subsequent Electricity Shortage Review Committee recommended, among other things, that ECNZ and the ESAs consider removal of the cap on spot prices, noting that the existing mechanism could "not be expected to bring supply and demand into balance during periods of shortage". It further recommended a shift to a 1-in-60 dry-year security standard (in place of the 1-in-20 dry-year standard then used by ECNZ), financial incentives and education (with a role for government) for consumers, to reduce demand and improve energy efficiency; and measures – notably longer-term contracts between ECNZ and its customers – to improve supply security by providing better information on demand trends and generation requirements. Referring to the contemporaneous work being undertaken by the Wholesale Electricity Market Study (WEMS), the Committee expressed a view that a wholesale electricity market could be expected to address the then concerns regarding supply security, information flows and incentives for electricity efficiency.

### *2001 Winter Crisis*

If the 1992 winter crisis showed that the reforms had provided a less government-directed, more industry-led and more customer-focused response to crisis – even with some imposed cuts to water heating – the 2001 crisis demonstrated the benefits of subsequent reforms. Most notable of those benefits were the signalling and rationing functions performed by the wholesale electricity market implemented in full since October 1996, and the benefits of competing generation created by the spinoff of, firstly, Contact Energy from ECNZ and then the further break-up of ECNZ into Genesis, Meridian Energy and Mighty River Power.

Early 2001 shaped up to be even worse than the lead-up to the 1992 crisis, with storage lake inflows in the first seven months of the year being the lowest in 71 years. Combined with stronger-than-usual demand growth and an unusually cold early winter resulting in record June demand levels, winter 2001 again posed the prospect of supply shortages.

Figure 6.2 demonstrates the reaction of wholesale prices and electricity consumption in the lead-up to and over the course of the crisis, and their correlation with hydro storage levels relative to average. Up to May, wholesale prices gradually rose in response to rising demand and falling hydro storage levels, but then experienced sustained and dramatic rises over June and July with daily average prices the highest seen in the market since its inception, but with little response from demand. However, a dramatic decline in wholesale prices coincided with a sudden decline in demand in the first half of August, even though hydro storage levels continued to decline. Importantly, the resulting energy savings were secured long before hydro reserves recovered in November/December. Also of note is the fact that South Island prices were often higher than North Island prices as excess generation in the north of the country was required to supply the south owing to low southern hydro storage levels (the reverse typically being the case because of the dominance of demand in the north, and south/north transmission constraints across the Cook Strait and through the central North Island).



Source: Robertson et al. (2003).

*Government Steps in on behalf of Industry*

To combat the crisis, government – as opposed to industry – stepped in to support a “10% reduction for 10 weeks” voluntary electricity conservation campaign, reflected in declining wholesale prices over August through to November. Larger electricity customers who had not hedged all or enough of their electricity requirements faced the full wholesale spot price and, where they could, began reducing production and rescheduling maintenance so as to limit the impact of the price rises. Additionally, Transpower was able to alleviate some of the effects of the shortage that resulted from transmission constraints by relaxing certain system security standards (i.e. by running the grid harder). Peak seasonal demands were mainly over by September and, with storage levels then starting to trend towards normal, wholesale prices had fallen to more usual levels.<sup>5</sup> Compulsory restrictions, widespread water-heating cuts and blackouts had been avoided.

*Residential customers Insulated but NGC Exposed*

Importantly, residential customers remained largely immune from the wholesale price rises over the course of the crisis, continuing to enjoy stable retail prices despite the increased wholesale market volatility. However, the retail arm of Mighty River Power, Mercury Energy, even offered rebates to its 250,000 customers if they saved power, offering them an opportunity for financial gain. At one stage NGC, which had only recently acquired 76% of the then largest energy retailer, TransAlta New Zealand, attempted to increase its prices to better reflect its wholesale electricity costs. However, it found this could not be sustained since hedged parties – including generators that had begun to acquire or set up their own retail operations – did not face the same pressures to increase retail prices. Instead the company – originally a gas network operator and trader that diversified into electricity - opted to sell its retail customer base and exit its electricity industry investments following heavy losses.

NGC’s exposure arose because hedge contracts it used to hedge its spot wholesale electricity price risk expired in May 2001, when the crisis was well underway, and it found itself unable to secure new hedges at prices it regarded as acceptable (having declined contracts in February and March at prices it regarded as too expensive).<sup>6</sup> This situation was argued to demonstrate a competitive failure of the reformed industry, in that the generators from which NGC sought new hedge contracts were now its main retail competitors. However, the question remained why NGC had not secured replacement hedge contracts well before its existing contracts had expired, and the fact that its attempt to raise retail prices was thwarted by the actions of those very same generators could also be interpreted as a plain example of retail-level competition benefiting residential customers in the midst of an industry crisis. By this measure, the wholesale market might be argued to have “weathered” the 2001 crisis commendably.

<sup>5</sup> Indeed, above-average storage inflows in December caused prices to fall to near zero, resulting in the first use of the market’s must-run dispatch auction.

<sup>6</sup> See “Mighty River Contracts ‘Vindicated’ in Wholesale Power Price Crisis”, *National Business Review*, 24 August 2001.

*Reformed Arrangements Criticised*

Despite this, however, aspects of the industry and wholesale electricity market response to the crisis drew criticism. Retail prices – being in a sense fixed prices that energy retailers are prepared to offer so long as they can cover their electricity purchase or supply costs on a risk-weighted basis – began to rise following the winter crisis. In part this represented the market’s recognition, conditioned by recent experience, that future wholesale prices might dramatically rise in a similar fashion in any future electricity shortage (in much the same way that insurers raise premiums following adverse claims episodes). Generators with capacity surplus to that required under customer contracts, or to satisfy their own retail customer demand, were potentially able to reap significant profits by selling into the wholesale market at unprecedented prices.<sup>7</sup> Net purchasers, though, bore higher prices on their wholesale market purchases. On the other hand, larger customers with electricity supply contracts potentially benefited from the high electricity prices by being able to voluntarily reduce demand and sell surplus power on the wholesale market at significantly higher prices. Increased transmission constraint rentals resulting from the higher prices were passed on to distribution companies as a windfall gain.

None of these were a “good look” for industry, particularly in the eyes of those users exposed to the spot price, and these events were accompanied by allegations of market-rule gaming and abuse of market power by generators, followed by the customary calls for government intervention and changes to market rules and industry structure. For its part government at that time resisted calls to explicitly cap wholesale prices and otherwise to intervene, instead warning the industry that the future of the market rested on the effectiveness of its response to the crisis.

*Reformed Arrangements Rise to Challenge*

Once again, however, it is worth noting that the responses to the 2001 winter crisis continue to demonstrate clear breaks with reactions of the past. While government took a greater role in supporting calls for voluntary savings than it did in 1992, and threatened industry that it needed to respond to the crisis effectively if the market was to endure, the 2001 crisis was characterised more by Adam Smith’s “invisible hand” than by the guiding and constraining hand of government.

The market mechanism did in fact keep the lights on, despite being distrusted by many because of its lack of any discernable personage taking responsibility for coordinating suitable responses to the crisis, and resented by politicians who begrudge real power in the electricity industry being out of their hands. It effectively rationed scarce electricity to those who valued it most, with exposed customers who could reduce their demand rationally choosing to do so (and possibly making on the deal by selling surplus power

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<sup>7</sup> Although, as shown in Chapter 3, generator profits were not abnormally high, perhaps reflecting their fixed-price contract positions.



at the increased wholesale price), and others either being insulated from the price rises (notably residential customers or those with fixed supply contracts) or making the assessment that they would face worse costs than the wholesale electricity price if they chose not to consume. This is how markets are intended to work, using price to ration resources to those who value them most highly. The fact that the price in question experienced significant increases has been argued to indicate market failure, but instead it would appear a natural consequence of price-inelastic demand combined with tight supply,<sup>8</sup> and a useful response to a very real supply crisis caused by lack of rain.

Certainly it can be emphasised that residential-customer energy savings came about with a call, supported by government, for voluntary savings. This, however, gives no credit to those power companies offering their customers bill reductions for reducing consumption. Nor does it indicate a failure of the market and a need for government intervention: as the 1992 crisis demonstrated, the industry was capable of making such calls. And nor should a call for quantity reductions be taken to mean a failure of the price-based market mechanism. While it can be (and is in Chapter 7) debated whether the reformed industry structure dampened incentives for the adoption of price-based signals at the residential level, the reality was that in winter 2001 residential customers by choice or lack thereof faced fixed electricity charges that insulated them from the worst of the wholesale price rises without consumption being constrained.

#### *Voluntary Savings Displace Rationing*

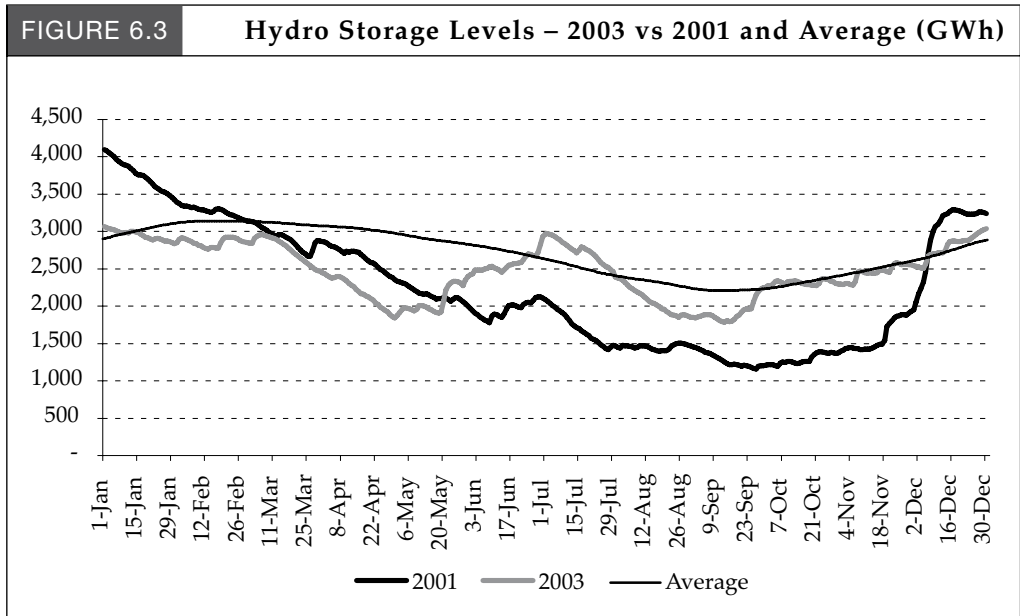
In the absence of a price-based mechanism for such customers to be encouraged to reduce their demand when supply is under strain, more quantity-based measures are required. It is too much to expect sustained low prices and continuing demand in times of shortage at least across all consumers, irrespective of whether electricity supply is determined administratively or by market forces.<sup>9</sup> A subset of electricity consumers may be economically insured by fixed prices that incorporate a risk premium, provided that a significant portion of demand has the incentive and ability to vary in response to price changes. That calls for voluntary reductions were adequate, and reductions and blackouts avoided, demonstrate a clear improvement of the current regime over that prevailing before the reforms. It also indicates an improvement over the situation in 1992 when conservation signals were slower to arise, price-based rationing was of limited effect, and some supply restrictions were necessary despite strong voluntary reductions.

<sup>8</sup> Short-term electricity supply should be expected to become more price-inelastic during a supply shortage, with the scarcity value of water – its “opportunity cost” or “shadow price” – sharply increasing. See Box 3.2.

<sup>9</sup> In this regard it is instructive to recall New Zealand’s response to past oil price shocks, before the widespread market-based reforms of the 1980s. Where petrol prices rose in response to the shocks, consumers had incentives to economise on fuel use and invested in fuel-efficiency by opting for smaller vehicles and converting existing vehicles to run on cheaper domestic compressed natural gas. Government augmented such price-based measures, however, by imposing car-less days and reducing the open-road speed limit to 80 Km/h, regardless of the unequal burden of such measures on different road users. So far residential electricity consumers have effectively been able to avoid either type of measure during the post-reform crises.

### 2003 Winter Power Scare

On the basis of observed hydro storage levels over the first five months of 2003, demonstrated in Figure 6.3, it was feared that winter 2003 was shaping up to be at least as much of a crisis as winter 2001. In fact, as early as December 2002 wholesale electricity prices rose strongly in response to lower-than-average November inflows, but quickly returned to more normal levels.



Source: M-Co data (unpublished).

Following government's 2001 warning that the market's survival depended on an effective industry response to the then winter crisis, industry participants formed a steering group to monitor and report on likely supply-shortage scenarios and to plan for a coordinated industry response in the event of another dry winter. In 2003 that group convened in February but, given the early indications of a looming winter crisis, the planning and preparation of industry's response was taken over in March by the Grid Steering Committee (GSC), with calls for 5% voluntary reductions being made in April.

#### Wholesale Market gives Early Warning

By that time spot prices were almost as high as at the beginning of the 2001 crisis, reflecting not just lower-than-average hydro inflows, but also new fears over the security of domestic gas reserves required for thermal generation. Output from the country's main gasfield – Maui – had already begun to run down, but in 2003 its expected productive life was revised downwards, causing a reconsideration of gas-

based generation projects already in train, and accelerating plans for further gasfield development and exploration. Once again the wholesale electricity market gave early warning of impending supply shortages and provided industry players with the necessary incentives to economise on demand and conserve scarce hydro resources for peak winter demands. The 2003 crisis failed to materialise, however, with mid-year hydro inflows being sufficient to alleviate earlier shortfalls and to return storage to average levels. Despite a dry start to the year, it rained.

### *Government Intervenes despite Disappearing Crisis*

Regardless of this outcome, and reflecting industry's difficulty in establishing a comprehensive industry-wide governance system and government's stated dissatisfaction with industry's management of dry years, in May 2003 government announced the establishment of a previously foreshadowed Electricity Commission. Among other things, the Commission has been charged with managing the electricity sector so that demand can be met in a 1-in-60 dry year (i.e. the standard recommended following the 1992 crisis) without the need for national energy conservation campaigns. To this end it is required to contract with generators for dry-year reserve generation capacity and reserve fuel, and with customers for interruptible load. As such it appears government has adjudged the extra costs of reserve generation and interruptible load – direct and indirect, obvious and subtle – preferable to occasional calls for voluntary energy savings and the enhancement of price-based signals to residential customers for any necessary rationing. This is despite the apparent ongoing success of savings campaigns in California, and its switch towards meeting new demands through energy savings and efficiencies.<sup>10</sup>

In September further details of these measures were released, including the trigger price for dry-year reserve generation being set at \$200/MWh (or lower should the Commission consider that lake levels are sufficiently low). Other measures included the reserve energy supply being capped at 1,200 GWh over a four-month period, an energy price levy to be borne by electricity consumers to fund dry-year reserve, and government contracting with Contact Energy to build and operate the 155 MW thermal station at Whirinaki to form part of the dry-year reserve at a cost of \$100m (commissioned in June 2004).

While these moves cannot be attributed to the abortive 2003 winter crisis, the timing of their announcement by the government would appear to reflect apparent urgency as the crisis loomed. In the discussion below, and elsewhere in relation to matters such as encouraging investment in new generation (Chapter 10), the wisdom of these measures is considered.

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<sup>10</sup> Interview with Wally McGuire, designer of California's 2000 and 2001 savings campaigns, while he was in New Zealand to speak to the Energy Efficiency and Conservation Authority, on National Radio, 24 March 2004, and "The Secret Surplus Beats Power Crisis", *Dominion Post*, 23 March 2004.

### *1998 Auckland CBD Outage*

Other than the above winter crises, the New Zealand electricity sector in recent times has not experienced other crises of nearly the same magnitude. In 1998 a sequence of critical high-voltage underground cables supplying the central business district of Auckland failed, with the result that downtown Auckland faced months of blackout. However, these failures were found by a Ministerial Inquiry to be reflective of poor maintenance and security planning by the local lines operator, then Mercury Energy. While poor corporate governance and accountabilities were found to have played a role in the poor practices leading to the crisis, these provide at the very most a tenuous link between the current reforms and the Auckland power crisis. The root cause lies more in long-term maintenance policies and network management preceding corporatisation. In any event the crisis was localised, and the national electricity system remained sound.

### *2004 Loss of the HVDC Link*

Transitory spikes in the wholesale electricity price of the magnitudes experienced during the 2001 and 2003 winter crises have also been experienced in response to outages in the HVDC link and various generators with little fanfare. However, in January 2004 a more significant loss of the HVDC link occurred when strong seasonal gales toppled three South Island transmission towers. This resulted in physical separation of the South and North Island electricity systems for a number of days, and dramatic rises in North Island wholesale electricity prices. The extent of the price rise (from \$50/MWh to \$810/MWh at one point; and as high as \$1,083/MWh, which compares with the peak of US\$7,500, or \$10,900 at the then exchange rate, experienced in the US midwest in summer 1997) caused some major electricity users to allege profiteering by generators and faults in the wholesale electricity market price-setting mechanism.<sup>11</sup> The incidence of these price rises was naturally determined by retail supply and hedge contracts, and offered some major users the opportunity to profit by curtailing demand and selling contracted power at the increased wholesale price.

Since the outage did not reflect an impending supply shortage, and occurred over the summer period when demand is traditionally lower, other power savings measures were not called for or required. A handful of major industrial users exposed to the spot market opted for production cutbacks and rescheduling of planned maintenance rather than bearing the increased power costs, but power savings by other users were not required as existing generation was able to meet demand (in this instance, within each of the temporarily disconnected North and South Islands).

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<sup>11</sup> As discussed in Chapter 9, when summer floods in February 2004 caused a spike in fresh vegetable prices, with price rises of 200% in some cases, the market mechanisms for selling produce were not questioned, and even the chief executive of Consumers' Institute resignedly explained the increases in terms of basic supply and demand.

*Reformed Arrangements Survive Major Challenge*

Replacement transmission lines were installed by Transpower within days and wholesale prices returned to more normal levels. In this instance existing industry contingency plans and the wholesale electricity market alone were able to resolve a supply crisis, with wholesale prices rising to shed demand while maintaining supplies to those prepared to pay the considerably higher prices. Despite the loss of South Island generation to demand typically centred mainly in the North Island, the vast majority of electricity consumers were oblivious to the event. The outage did, however, illustrate dramatically the market and associated price separation that would occur with grid constraints.<sup>12</sup> With dry-year reserve generation since June 2004 being used during grid emergencies and when spot wholesale prices otherwise rise above \$200/MWh, such dramatic price responses will be somewhat attenuated for future HVDC outages. This generation is funded by an electricity consumer levy, and dampens price cues for the optimal timing, scale and location of new generation.

## DISCUSSION – WHOLESale ELECTRICITy PRICE RISES: CURE OR DISEASE?

The 2001 winter crisis, abortive 2003 winter crisis and 2004 HVDC link loss provide three useful case studies with which to assess the reformed industry arrangements, and the wholesale electricity market in particular. Not only can the performance of the system during these crises be compared with the system's more typical performance, but it can also be contrasted with the performance of the pre-reform system under the various earlier crises.

Of particular interest is the role played by, and performance of, the wholesale electricity price. As noted above, wholesale electricity prices have risen sharply when impending winter hydro shortages have become apparent. In so doing they have provided early warning of possible shortages, and simultaneously encouraged conservation of scarce hydro reserves – by providing larger customers exposed to the spot price with the required incentive to reduce consumption, and by providing hydro generators with a market-based signal of what premium electricity consumers placed on conserving water for peak winter demands. In a sense sky-rocketing wholesale electricity prices provided a market-wide assessment of the value of increasingly scarce hydro reserves in the face of looming winter energy demands.<sup>13</sup>

In each case no individual or group of individuals has decided on behalf of consumers which of them must reduce demand in order to conserve supplies and, in contrast to the

<sup>12</sup> Such separation affects not just the spot price but also hedge arrangements. For example, in this episode a generator producing at the South Island spot price but with a customer hedge in the North Island would have to make significant payments under the hedge and at the same time get a lower price for its generation.

<sup>13</sup> As mentioned earlier, a measure of the "shadow price", or "opportunity cost", of water.

pre-reform experience, imposed reductions have been avoided. Consumers have either been sheltered from drastic price increases, or have been able to choose for themselves their best course of action in the face of rising prices. Decision-making power has been in the hands of those facing the risks and costs of a poor decision rather than imposed on them by others.

### *Lack of Customer Choice?*

It might be argued that some consumers exposed to rapidly rising wholesale electricity prices face no choice at all, in that they cannot afford to reduce their consumption. Such is the case in the short term for industrial customers with customer or production commitments. However, such customers have the option of entering into supply contracts with generators to hedge their exposure to wholesale prices, and in any event their inability to bear customer losses or plant shut downs if they reduced electricity consumption represent the very avoided costs that make the increased wholesale prices bearable. Should those prices continue to rise, a point will eventually be reached at which it becomes cheaper to lose customers and shut down plant rather than continue consuming electricity. It is precisely this mechanism that determines who values electricity the most, and ensures they can continue to receive it when it is in short supply. In the longer-term it also encourages such users to negotiate more flexible customer arrangements, and to invest in production flexibility.

The fact that certain customers have plant, cost structures or supply commitments affording them less flexibility in their electricity consumption than others is simply a reflection of their own business risks and decisions. While for some consumers this may reflect historical choices based on pre-reform electricity arrangements, after nearly 20 years of reform it is hard to see how those choices are not now those consumers' own responsibility. Similarly, the fact that dramatic rises in wholesale electricity prices can be required to bring available supply into balance with demand during times of crisis is not an automatic sign of profiteering by generators, but rather indicates the extremes to which certain customers are prepared to go to ensure security of supply.<sup>14</sup> As above, there will come a point at which wholesale price increases of sufficient magnitude and duration will encourage those customers lacking flexibility in their electricity consumption to explore more flexible and/or energy-efficient alternatives. When price signals are not available, other less-direct means are required to persuade consumers to change their consumption choices. In short, if there weren't electricity consumers willing to pay such high wholesale electricity prices to ensure ongoing supply, those prices would not need to rise so steeply to maintain balance between energy demand and available supply. Wholesale price spikes therefore encourage conservation.

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<sup>14</sup> Similar extremes can be observed in other industries, such as pulp and paper mill operators requiring top-up log supplies to ensure plants do not suffer expensive shut-downs, or fishers needing to buy top-up fishing entitlements to avoid penalties for over-catching. That the needs of such operators can translate into apparently inflated log and fish quota prices are not automatic signs of failures in the forestry sector or quota market.

*Larger Customers Bear Disproportionate Burden?*

It appears that some larger electricity users regard themselves as bearing a disproportionate share of electricity price rises when tight supply conditions result in rapidly rising wholesale electricity prices.<sup>15</sup> This is particularly so given the fact that most smaller electricity users enjoy fixed-price contracts which shield them from those rises, and therefore do not induce conservation or efficiency measures at the small-consumer level in times of shortage. However, many such smaller users choose to bear higher-than-average fixed prices in exchange for granting suppliers an option to interrupt their load through ripple control on electric water-heating. Moreover, in times of supply shortage the small-customer sector is often exhorted to reduce, and responds by reducing, their consumption via voluntary energy-saving campaigns. Also, the suggestion that larger users bear a disproportionate share of wholesale price risk presumes that hedge contracts cannot be secured or, if they can be, only at high strike prices – which may well be true in the midst of a shortage, but then insurance policies are generally only useful when taken out before adverse conditions arise. Finally, the fact that larger electricity users face a greater exposure to wholesale prices than do smaller users is little different to the fact that large borrowers on the capital markets do not enjoy the same access as smaller borrowers to tailor-made lending options repackaged by financial intermediaries to better suit their risk preferences. If there is a rationale for financial intermediation it is that it allows such risk repackaging to occur, although larger customers will always find themselves needing to negotiate arrangements to suit their larger and/or more unusual requirements. Thus electricity retailing should be expected to offer smaller customers tailor-made risk-management options such as fixed-price contracts, but it would be ambitious to expect such options to be widely available for the largest customers.

*Inadequate Capacity?*

As a separate matter it can be argued that the frequency and extent of wholesale price rises during crises caused by the inevitable vagaries in the weather need not be as great, and reflect a failure on the part of industry to provide adequate capacity (or other market-based and non-distortionary solutions, such as widely-accessible power exchanges). If sufficient reserve capacity was on hand or non-hydro-based generation made available then the frequency or intensity of the crises would be reduced. Alternatively the high wholesale prices might be argued to be a reflection of artificial, arbitrary or faulty market rules or, as discussed in Chapter 9, generator gaming or abuse of market power.

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<sup>15</sup> Political sympathy to such a view, where forthcoming, seems to be predicated on the idea that a loss of electricity supply (or voluntary reduction in demand) is more costly to firms than to households, and household demand has historically been regarded as interruptible with lesser adverse consequence. Research from the Netherlands by De Nooij *et al.* (2004), however, estimates the value of lost load (VOLL) of firms to be 6 euros per kWh, versus 16.4 euros per kWh for households.

However, the size and duration of wholesale price rallies and the resulting increased profits enjoyed by generators during supply crises signal to investors that new generation is required, and provides a source of the returns required to fund such investments.<sup>16</sup> Electricity generation investments are sunk and long lived, and therefore require risk management devices, such as long-term fixed-price contracts, for their justification. To invest requires the prospect of an expansion in demand at current prices, or of an increase in prices as a result of increasing costs of alternative fuels. Price spikes in low-inflow periods constitute part of the signals about longer-term industry supply and demand imbalances that are relevant for generation (and demand management) investments. Of themselves, these episodes enhance the incentive to invest over those incentives provided by assessments of longer term demand and supply considerations. Generator (and/or consumer) profits enjoyed during wholesale price spikes are a necessary “evil” if future generation is to be provided to satisfy growing demand in a timely fashion. If the market does not provide these signals and incentives, then costlier or less efficient solutions are likely to be the alternative. For these reasons, an argument is presented in Chapter 10 that such supply-security considerations are an oxymoron in the context of a freely operating electricity market.

## RESERVE GENERATION RECONSIDERED

In the light of such comments it is useful to return to government’s proposal, during the abortive 2003 crisis, for the new Electricity Commission to contract for reserve generation to avoid the need for voluntary demand savings in dry winters. As noted above, this approach favours the costs of maintaining idle energy reserves in case of a “non-rainy day” over the arguably cheaper alternative of calls for voluntary reductions and encouraging improved demand-side response to the required energy savings. Electricity consumers will be required to fund such reserve capacity through a levy on electricity prices, irrespective of whether they care for such “insurance”. More to the point in this context, however, is the fact that such reserve generation will be operated with a maximum trigger price of \$200/MWh, as set by government.<sup>17</sup>

Since the proposed reserve generation is for a maximum of 1,200 GWh over any four-month period, the proposed trigger price (which might be lower if the Commission chooses, and which applies any time wholesale electricity prices exceed the trigger price, not just in dry-year winters) is not a fixed cap on wholesale electricity prices.

<sup>16</sup> Of course, hydro generators may incur losses with higher spot prices if their hedge positions, for example, simply covered average inflow years and their output was reduced by the low inflows that produced higher prices. This prospect may induce supply-side response and investment in demand management by vertically integrated generator and retailers.

<sup>17</sup> It is instructive to compare this trigger price with ECNZ’s \$150/MWh cap on the wholesale electricity price under its rudimentary spot market in 1992, and the Electricity Shortage Review Committee’s comments on that cap’s undesirability when attempting to bring supply and demand into balance during supply shortages.



Instead it will limit the duration of wholesale price rises, in effect reducing the area under the wholesale price chart (such as was shown in the upper graph of Figure 3.11) where prices rise over a crisis, such an area having been paid for in advance in the form of the reserve generation levy. If and when the reserve energy is depleted, wholesale prices would continue to rise as before, thereby continuing to provide the important signals and incentives to generators, consumers and investors alike as discussed above. However, the reserve trigger price will dampen the signals and incentives to these parties to suitably respond to crises, and reduce the necessary profits to generation over their course. Price caps – soft or hard – discourage conservation, and undermine new investment in generation and energy efficiency.

At the same time the reserve trigger price will “crowd out” the need for market players to establish their own desired means and levels of protection against supply insecurity, such as hedge contracts or self-generation, or will result in parties with such protections effectively paying twice for the privilege. To the extent that its level is set by government or subsequently by its agent, the Electricity Commission, uncertainties regarding the basis on which it is adjusted or applied present an additional risk to be considered by parties contemplating electricity-sector investments.

Further, the regime suggests that higher-cost generation be held in abeyance for times of shortage – because if it is not more expensive than existing plant then surely it would be economic to operate it at other times and thereby render it “just another” generator. Indeed, the model is one of a plant with high operating cost, which if unaccompanied by relatively low capital cost would be uneconomic to construct from scratch.<sup>18</sup> This suggests that older plant with sunk capital cost and higher operating cost would be appropriate for generation “in reserve”; but that was exactly the situation prior to the reserve generation regime.

The reserve proposal suffers the common “moral hazard” problem of any insurance policy, namely the dampening of incentives for parties to mitigate the very risk being insured. At the same time it diminishes the discretion of electricity consumers to determine for themselves the trade-offs they are prepared to make between price and security of supply. This ignores the fact that some consumers are well placed and quite prepared to bear the risk of shortages in supply – that discretion, to a point, has now been assumed by government on consumers’ behalf. Finally, at a more subtle but important level for the long-term development of the sector, the process for setting and applying the reserve generation trigger price represents a new form of political risk to investors in new generation. This is not a head-on collision between politics and the market, but it is not just a near-miss either.

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<sup>18</sup> The contrast here is between open-cycle plant, requiring low capital expenditure but with high operating costs and high emissions, versus more efficient combined-cycle plant, requiring high capital expenditure but with low operating cost and low emissions.

## CONCLUSION

This chapter has argued that weather-driven supply insecurities are to some degree inevitable, given the finite resources to invest in the electricity sector. Indeed, this is even a desirable state of affairs given the cost of trying to ensure absolute supply security. The experience after the reforms – both in 1992 and subsequently – has in fact been considerably better than in the past, which typically involved the blunt instrument of blackouts. Since the reforms, and especially with the advent of the NZEM, supply insecurity has been felt more in terms of rising wholesale prices – but not retail prices, at least not immediately or extremely – illustrating how this innovation has provided a useful tool for managing supply insecurities. The reserve generation scheme reduces the effectiveness of this tool, and potentially exacerbates the problem of rationing tight supply. Hence, despite an often-expressed view that the reforms have worsened or even caused supply insecurity, in the main they have “weathered” tight supply situations better than before. The ability of the system to manage future supply insecurities may or may not have improved with the advent of the Electricity Commission.

*In this chapter we contrast the lack of demand-side initiatives pre-reform with those emerging, at times under duress, post-reform. Retail electricity customers in New Zealand clearly now enjoy much greater choice as to their energy supplier (discussed in Chapter 5), even if their local lines remain monopolies. That this translates into greater competition in generation and energy retailing remains the case, even given New Zealand's somewhat unusual convergence on vertically integrated generators and energy retailers. Furthermore, despite this industry configuration, it has been possible for lines companies to elicit demand-side responses saving on network capacity, effectively uncoupling peak demand from energy growth. We then go on to take a critical look at the nature, purpose, objectives, and targets of demand-side initiatives such as those advocated by the Energy Efficiency and Conservation Authority (EECA).*

*In short, we argue that the most promising innovation in this area is the development of power exchanges at the retail customer level, which would augment an equally desirable innovation – load-limiting fuses with capacity subscriptions – discussed in relation to ensuring supply security in Chapter 10. The combination of such innovations would give smaller consumers (those who currently lack both price signals and a willingness to alter short-term demand patterns in response to price changes) the incentive and opportunity to profit by curtailing their electricity demand when supply is tight. The benefits of price-responsive demand are clear. What is less clear is whether consumers are interested in making the trade-offs required to achieve those benefits.*

## INTRODUCTION

### *An Increasing Focus*

The nature and importance of electricity-user participation in the changing electricity industry equation is a matter receiving increasing focus. This changing focus can be seen as a long-overdue piece in the electricity reform jigsaw, or recognition that quality and supply certainty are more important in the e-world of a modern economy. It could, however, simply be an afterthought to the state-dominated supply-side focus in the New Zealand electricity sector of almost a century. Covering a range of matters as diverse as power exchanges and pre-payment meters, through to real-time electricity pricing and disclosure of all wholesale electricity market bids and offers, demand-side participation discussions can degenerate into circuitous debate. There are very real reasons to wish to encourage improved demand-side participation in the electricity sector, but it is essential that the suggested measures do not defeat the purposes they are intended to achieve.

*Economic Issues*

As summarised in Chapter 2, the relevant classical economic analyses fall into two areas. The first is to do with the impact on consumers of suppliers having market power, in the extreme case monopoly power. Conventional economic analysis predicts that consumers suffer both higher prices and lower supplies in the presence of such market power, and that suppliers with market power enjoy greater abnormal profits. These effects are worsened where demand is unresponsive to changes in electricity price. Thus, increasing demand's responsiveness to price should lessen the impact of any generator market power (less so for transmission and distribution market power, to the extent that their charges have fixed components). In turn, this reduces the need for distortionary market interventions, such as price caps, which hinder investment and worsen supply security.<sup>1</sup>

The second relates to the relative burden of supply (or demand) shocks when electricity demanded by consumers is less responsive to changes in electricity price than that supplied by electricity suppliers, particularly in the extreme case where electricity demands (especially in the very short term) do not change at all in response to price changes.<sup>2</sup> Such analysis predicts that consumers bear the impact of sudden changes in supply (or demand) in the form of higher prices, and that suppliers enjoy both those higher prices and sustained levels of demand (which may or may not translate directly into higher profits, depending on whether, for example, the supply shock was due to rising supply costs). Both branches of analysis predict benefits of some magnitude to consumers in increasing the responsiveness of consumer demands to changes in price, which presumes both that consumers face changes in electricity prices (as opposed to fixed prices) and that they have the desire or cost-effective capacity to alter their consumption patterns when they do.<sup>3</sup> Additionally, where demand becomes more price-responsive, requirements for new and/or peaking generation are reduced, with associated financial and environmental benefits. Simultaneously, price-responsive demand reduces the probability that electricity markets will not balance, thus improving supply security.

*Main Demand-Side Thrusts*

Accordingly, initiatives to improve the electricity sector's demand-side response have had two main thrusts. The first has been directed at providing electricity consumers with greater choice as to whom they buy their energy from – ensuring the sector is structured, and market rules are designed, to ensure competition among suppliers, and thereby to ensure that consumers are not captive to rises or volatility in electricity prices. In a sense this treats the problems of price-inelasticity in demand (and/or supply) as given. Instead it concentrates on ameliorating the adverse consequences to consumers

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<sup>1</sup> See Meade (2005).

<sup>2</sup> Conversely, in such circumstances very small changes in demand (e.g. due to sudden weather changes) affect prices very considerably.

<sup>3</sup> Additional considerations arise, for example, in respect of the more subtle yet important matters of risk-preferences, as well as time-preferences, and informational costs and asymmetries.

of any market power in generation (and also in transmission and distribution), or from market arrangements being “gamed” (see Chapter 9).

The second thrust, in effect, seeks to increase the price elasticity of demand, in other words increasing the ability of and incentives for consumers to alter their electricity consumption in response to short- or long-term price changes. Once again, this is both to encourage competition and to mitigate any market power effects. However, it runs up against the likely preference of at least some customers for low-risk, fixed-price supply contracts that enable them to insulate their consumption from changing supply circumstances.

In turn, both of these thrusts require other measures, such as efficient means of changing electricity suppliers, greater information on and incentives to invest in energy efficiencies as well as to respond to changes in electricity prices, and a transmission grid not giving rise to constraints that can lead to short-term and/or regional instances of market power (see Chapter 9).

## HISTORY OF DEMAND-SIDE PARTICIPATION

### *Pre-Reforms*

Moves to encourage greater demand-side participation in the electricity sector have not been easy or rapid, for understandable reasons. For most of the twentieth century the sector was largely centrally planned and controlled, and focused in the main on supply-side issues. Recurring supply shortages and increasing constraints on the funding required to ensure that supply kept pace with ever-growing demand presented ample reason for demand efficiencies to be achieved. However, in the absence of strong price-based signals for users to economise and a lack of political will to give such signals, consumers faced little reason to change their demand habits, and government had few means to give them any.

As a consequence, demand-side participation has meant historically in New Zealand little more than ESAs or government dictating to consumers when or how they could not use electricity. As discussed in Chapter 6, these “measures” have taken the form of rolling blackouts, cuts to television broadcasting hours, electric water heaters being turned off during supply shortages, or war-time regulation limiting the types of appliances that could be purchased and used. Little regard was had to the unequal burden of such impositions on different classes of users – consumers were simply “getting what they were given” and “doing what they were told”. Administratively determined electricity prices, particularly where they were maintained below economic levels, encouraged inefficient technologies and consumption – giving little incentive to conserve energy or invest in energy efficiencies – and required greater investment in generation to meet demand than was otherwise required. Their effect on consumer welfare would likely be even worse now in an e-economy where even the smallest electricity consumers rely upon the continuous availability of digital devices.

*Industry Initiatives Post-Reform*

The first winter supply shortage experienced by the reformed industry in 1992 illustrated that a fundamental shift in thinking had occurred. While the industry was still only partially decentralised and still under the dominance of state-owned monopoly generator Electricity Corporation of New Zealand (ECNZ), greater emphasis was placed on the need for consumers to determine how best to achieve required energy savings. Until very recently this has remained the main thrust of responses to winter crises, but the reserve generation requirements placed on the new Electricity Commission from 2004 (discussed in Chapter 6), and the Commission's imminent power to require electricity purchasers to hedge their exposure to wholesale electricity price movements, now provide a conflicting focus, dampening the price signals for required savings and reducing the incentive for investments in energy efficiencies.

Industry – meaning at that time ECNZ, a handful of major electricity users and the ESAs – did in fact initiate some of the most important measures to facilitate a demand-side response.<sup>4</sup> As discussed in Chapter 5, the instigation of a major wholesale-market development study in 1992, and the formation of the Electricity Market Company (EMCO) in 1993, were industry-led steps resulting in the development of the wholesale electricity market operating from October 1996. By providing wholesale electricity price signals, this one development has moved the New Zealand electricity sector considerably closer to the objective of encouraging electricity users to conserve electricity when supply is scarce, and to invest in energy efficiencies, thereby reducing the need for new or peaking generation and their associated financial and environmental costs.

To facilitate customer changes of electricity supplier, industry developed a multi-lateral agreement in 1994 allowing the reconciliation of electricity inflows and off-takes,<sup>5</sup> which were necessary requirements for determining whose contractual arrangements were associated with which actual electricity flows. For larger customers, where the installation of time-of-use meters was economic and facilitated supplier competition for customers, customer switching has been relatively forthcoming. However, for smaller customers, meters to record customer energy usage at different times of day were too costly and so it remained difficult for energy suppliers to accurately assess the demand characteristics of new customers (an essential characteristic for them to manage their pricing exposure). Accordingly competition between suppliers for new customers at the smaller end of the market was slow to develop, as was the ability of retailers to signal to smaller customers the changing value of the electricity they consumed.

As a result government became impatient with progress towards supplier competition, warning industry in 1998 that if it did not find a means of facilitating domestic

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<sup>4</sup> As suggested in Chapter 8, this was perhaps as much an industry reaction against ongoing political interference in the sector (despite its corporatisation), as specific government policy.

<sup>5</sup> Metering and Reconciliation Information Agreement (MARIA).

retail competition then it would institute a means to do so. Industry responded by implementing a system of deemed profiling in April 1999, thereby better enabling it to manage its supply risks when acquiring or shedding customers without the need to install real-time energy usage meters. With a government-enforced split-out of lines businesses from their energy and other competitive operations, with the break-up of ECNZ into competing companies, and with generators rapidly acquiring newly available retail customer bases so as to hedge their exposure to wholesale electricity price volatility, customer switching from one energy supplier to another became an almost overnight phenomenon. At the same time, retailers improved their ability to tailor rebate schemes for un-metered customers who made energy savings during supply crises, a useful step for encouraging savings when required.

### *Supply-Side Structural Stalemate or Equilibrium?*

Subsequent industry rationalisation, involving among other things generators becoming sufficiently vertically integrated so that further customer acquisitions were not an ongoing imperative, eventually resulted in a reduced appetite for supplier competition for customers.<sup>6</sup> Interestingly, customer switching had become at least as much a supplier initiative – with generators and other retailers selling or trading their customer bases – as a reflection of customer decisions to change supplier to secure a better deal. While customer switching remains an ongoing activity – facilitated for example by the New Zealand Consumers’ Institute offering a free internet-based electricity pricing comparison service – a perception by some remains that consumers face little competition among energy suppliers and hence continue to have little effective choice when it comes to finding cheaper electricity suppliers.<sup>7</sup> Curiously, this perception persists despite the evidence in Figure 5.5 showing that most retail customers are now able to choose from three or more energy suppliers in any given area.

An alternative explanation suggests that the rapid vertical integration of generation and retailing in New Zealand is in fact a natural and desirable outcome – a form of structural equilibrium – given the economics of generation and retailing. As suggested in Chapter 3, it must be seriously questioned whether stand-alone energy retailing is a viable business model unless and until a highly liquid long-term energy contracts market is in place (preferably naturally rather than as a regulatory artifice), or until

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<sup>6</sup> When generators scrambled to purchase customers off existing retailers in late 1998 they paid prices of between \$400 and \$1,200 per customer; in 2003 Genesis paid an average price of just \$120 per customer. “Low Price Paid for Customers”, *Dominion Post*, 24 October 2003.

<sup>7</sup> On 27 January 2004 the chairman of the new Electricity Commission (see Chapter 8) described on National Radio how in many parts of New Zealand there are only two energy retailers for customers to choose from, and that often both such retailers charged the same electricity price (i.e. suggesting this indicated a lack of competition). Such an inference cannot be safely drawn on such facts, however, since a consistency of prices in any given regional market could equally reflect either a perfect duopoly gouging customers, or perfectly competitive suppliers serving them well under the threat of entry (or other scenarios besides). To infer uncompetitive pricing it would be necessary to compare prices across different regional markets, and to take great care in interpreting the results.

retailing provides new “value-adds” over and above simple risk-management. Overseas experience shows that the size and composition of any electricity market, let alone the New Zealand market, present inevitable obstacles to the achievement of either. In any event, as discussed in Chapter 3, there are sound reasons why vertically integrated “gentailers” should continue to represent a more viable model, given the natural risk-management complementarities between generation and retailing.

#### *Hedge Market Regulation – Demand-Side Distortions*

Against this backdrop it is instructive to consider certain of the legislative changes enacted in October 2004 under the Electricity and Gas Industries Bill (discussed further in Chapter 8). Specifically, under this legislation, the Electricity Commission has been empowered to make regulations for generators to tender a minimum volume of supply contracts and make a market for energy hedge (including futures) contracts.<sup>8</sup> It will also be able to require wholesale electricity purchasers (which would include would-be retailers, and possibly irrespective of their embedded generation) to maintain minimum levels of hedge and contract cover.

Any such moves have the capacity to upset any natural risk-management equilibrium achieved by vertical integration, supposedly to improve risk-management options for presumably those larger customers who access contracts and other hedge markets, and potentially by increasing the exposure of other (e.g. residential) customers. While this has the apparent merit of promising to expose residential and other customers to wholesale electricity price movements to a greater degree than present (something which should encourage a demand-side response), for reasons discussed below this in fact might be inefficient and contrary to the preferences of many, especially smaller consumers.

By increasing the volume of supply and other hedge contracts available to would-be retailers any such regulations might encourage the re-emergence of independent retailing. However, the sector’s viability as a business model would then arguably be a function more of regulation than of economics, since it is not apparently viable under current arrangements. While this might be argued to increase competition for contracts and other hedges by deepening their associated markets, it is not clear that this would represent a net gain on current arrangements – even if certain (e.g. larger) users should be expected to benefit. In any case, encouraging greater contracting and other hedging is likely to conflict with the goal of encouraging a greater demand-side response to changing electricity prices, since contracting and hedging insulate users from those very risks. To the extent they shift the risk-management options from smaller users to larger ones (for whom demand-management is a more natural exercise), they might in fact lead to a net decrease in demand-side price elasticity.

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<sup>8</sup> In January 2004, the four large “gentailers” (Contact, Genesis, Meridian, and Mighty River Power) started trialling a financial market using electricity derivative contracts to manage energy price risks. See [www.energyhedge.co.nz](http://www.energyhedge.co.nz).



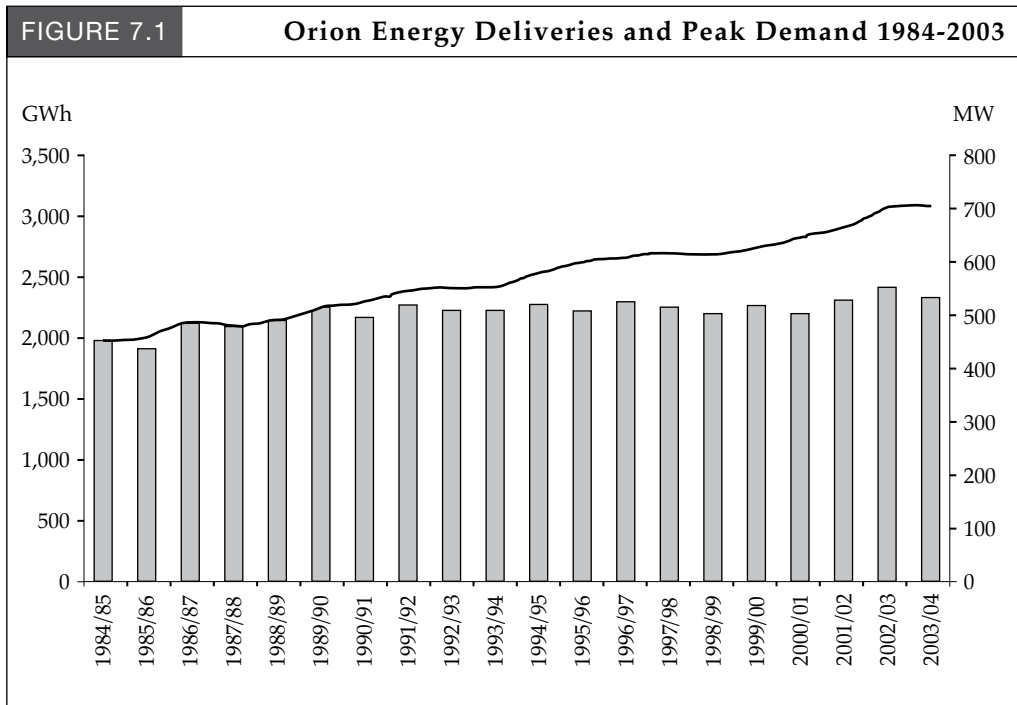
*Co-Investments in Demand-Side Initiatives*

One facet of vertically integrated gentailers alluded to but not developed is that competition within an oligopoly consisting of such firms imparts financial stability since they are less likely – certainly much less likely than small retail-specific firms – to be financially stressed to the limit by electricity market shocks. Backstop mechanisms for customers in the event of supplier insolvency can be given less weight in policy. In addition, the suppliers of electricity can take a longer-term view of customer relationships. Investment in demand-side management devices that share risk among supply and demand requires payback over time; and cooperating with customers installing such schemes is facilitated by an ability to budget on a longer-term view, albeit in a competitive environment.

Before the separation of lines and energy businesses in 1999, lines companies could interface directly with electricity consumers. Subsequent to this separation they do so indirectly, via the distribution tariffs they charge retailers (which maintain the direct customer relationship). These companies, via their predominantly local (trust) ownership and through the nature of their business, have a long-term interest in their customers that can facilitate the adoption of demand-side management, and they have an incentive to economise on costs by better utilisation of their networks. This is particularly the case in the management of demand volume, variations in which – e.g. peak loads – occur regularly; but it is less so in the management of price spikes arising from low lake inflows (here volume may be decoupled from energy price and the retailers' and lines companies' interests may diverge). Peak loads must be delivered across the local distribution networks and thus these loads set the capacity of these networks.

*Orion Energy – Decoupling Peak Demand from Demand Growth*

One example of load management by a combined retailer/distributor (to 1999) and a separated lines company (from 1999) is provided by Orion (2002). The company is 88% owned by Christchurch City Council, but is a corporation in which operating efficiently and producing some profit is important. It reports that in 1990, confronted with growing demand peaks requiring network investment, it instituted demand-management schemes for its customers that included, among other things, direct shifting of water heating off-peak (in the period when it could trade electrical energy), facilitating insulation of houses, establishing a gas supply business, and peak-load pricing. The consequences are illustrated in Figure 7.1 where it is apparent that peak demand, and hence network capacity growth, has been decoupled from the growth in energy demand. Orion estimates that the effect of its measures has been to delay, perhaps for a very long period, the need for additional generation and the accompanying network enhancements, suggesting a saving of \$180m based on an infinite delay. These outcomes occurred during a period where the use of a prime winter household heating energy source, coal, was essentially removed as a consequence of environmental regulation.



Source: Orion Energy.

Note: Peak demand (MW) is represented by bars; energy deliveries (GWh) are represented by the line.

Orion attributes much of its success to peak-load pricing that has induced customers of various sizes to institute a variety of electrical energy conservation measures under actions taken without its knowledge. If so, it illustrates the benefit of confronting decision-makers with the prices of their actions. The effect on decisions and the outcome cannot be duplicated by centralised decision-making. Although Orion's programme has had its prime effect on network capacity, it is also likely to have affected the demand for electricity: after all, insulation and alternative fuels also provide benefits at other than peak times. Indeed, Orion (2002) presents evidence that electrical energy use has not grown as fast as has the local economy, which would be in contrast to the economy as a whole (as comparison with Box 3.1 illustrates).

### *Metering Advances*

Reflecting a compromise measure but at least a useful first step, deemed profiling may yet give way to true time-of-use metering even for domestic customers as technologies improve and costs fall. Failing that, industry has demonstrated its ability to offer incentives for energy savings during supply crises, with Mercury Energy, and others, offering rebates to customers who made savings during both the 2001 and 2003 winters. To further enhance metering options, however, in November 2003 the state-owned generator Genesis announced that it and lines company Powerco

would start trials allowing it to measure half-hourly demands and monitor such information remotely (and hence more quickly than is possible with current manual meter reading). This in turn should enable it to introduce supply options that better reflect customer needs.

### *Power Exchanges*

On another front, Meridian Energy introduced the country's first power exchange in August 2001, allowing nine larger customers to resell contracted energy supplies, with 90% of the resold energy being that arising from voluntary demand reductions (e.g. by changing production schedules). Such exchanges help non-wholesale customers to assess the relative merits of using contracted energy supplies for their own use or selling it to customers who ascribe it a higher value, thereby facilitating an increase in the price elasticity of overall electricity demand. In October 2003 the largest New Zealand lines company, Vector, launched the country's first nationwide demand-side power exchange, focusing on medium to large users.

### *Former NZEM Initiatives*

In another industry initiative, the New Zealand Electricity Market (NZEM) Market Pricing Working Group (MPWG) in 2002 looked into a range of matters that had the potential to assist at least larger consumers – i.e. those typically at greater risk of wholesale electricity price increases. In the main concentrating on greater information disclosures on matters such as wholesale market bids and offers, transmission constraints, and data on the short-term reserve generation required to ensure system security, the group also investigated improvements in demand-side bidding and forecasting and the implementation of real-time pricing.

The motivation for greater information disclosures was that customers would be better able to detect anti-competitive pricing practices by generators, particularly when the wholesale market became fractionated by transmission constraints. It was also intended to enable them (i.e. mainly larger customers concerned with spot price movements) to better understand the relationship between final wholesale prices and factors such as hydro storage levels, fuel prices and demand.<sup>9</sup> In part this reflected the fact that final wholesale electricity market prices in New Zealand – based on metered demand and other factors after the fact – are not yet determined in real-time but instead some hours after bids and offers have been finalised for any half-hour trading period. Market participants – both suppliers

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<sup>9</sup> Ironically such greater information disclosures have the potential to increase the risks of any anti-competitive generator behaviour. Sought by purchasers as a means of detecting misbehaviour, they carry the potential to facilitate that very behaviour by better enabling competing generators to infer the pricing strategies and reaction functions of their counterparts. While such knowledge has the potential to encourage competition among generators, it also has the potential to enable cosy non-competitive behaviour, based on implicit agreements or otherwise, in which the New Zealand banks and oil companies have historically been accused of engaging. This is but one instance of how measures directed at enhancing demand-side responses could in reality defeat some or all of their purposes.

and purchasers – therefore bear mis-pricing risks that distort their ability to accurately respond to changing electricity prices in the short term. The real-time market initiative, seeking to closer align actual final prices and market participants' bids and offers, had the potential to better facilitate accurate load control, such as manufacturers turning plant off to avoid high wholesale prices.<sup>10</sup> With the NZEM's operations being taken over by the new Electricity Commission (see Chapter 8), however, that project is now on hold.

### *Electricity Commission Takes Over*

With the new Electricity Commission having taken responsibility for the electricity sector from 1 March 2004, government has squarely assumed responsibility for carrying the demand-side torch. With the perception of the potential supply-side structural stalemate discussed above, it is possible that the Commission will be left to rearrange the proverbial deck-chairs on the Titanic, focusing on matters such as standardising minimum terms for retail supplier customer contracts, streamlining consumer switching arrangements, and developing procedures for resolving disputes between customers and suppliers. Without forcing generators to shed their retail customer bases and engendering a fresh hunger among suppliers for new customers, the Commission may find that other initiatives such as energy efficiency and wholesale market refinements will be its most potent tools in the continuing development of demand-side participation, although neither have quite the focus required to change the behaviour or options of smaller customers. Alternatively it might reshape the structure of the industry by regulatory interventions rather than price signals, potentially increasing retail-level competition at the expense of risk-management efficiencies (to the benefit of larger users but to the detriment of both smaller users and the goal of engendering greater price-elasticity in electricity demand). Alternatively, it might usefully be a catalyst for the development of retail-level power exchanges, a move more likely to elicit the desired outcomes.

## ENERGY EFFICIENCY AND CONSERVATION AUTHORITY (EECA)

In parallel with industry-based initiatives to increase demand-side participation, the government body EECA was formed in 1992 to encourage voluntary public- and private-sector behavioural and attitudinal changes required to achieve government's goals for energy efficiency and conservation. Sensibly it recognised that the greatest scope for achieving such demand-side efficiencies is by targeting the industrial and commercial sectors (together accounting for 65% of annual energy demand, of which 90% is accounted for by just 300 organisations). It should be expected that if any parties are able to bear the costs of implementing energy-efficient technologies and other demand-side measures, they would be found among such companies. By contrast, the remaining 35%

<sup>10</sup> Counsell and Evans (2003) suggest that an ability to lock in prices a day ahead via a formal day-ahead market would benefit demand-management and price discovery. Such a market would supplement the effect of longer term hedge contracts, by covering additional unhedged throughput, albeit just covering day-to-day risks.

of annual electricity demand represented by domestic users is a considerable source of energy usage; but the dispersed, low level of that demand makes the economics of change less compelling (e.g. unlike ripple control of hot water systems, individual time-of-use meters are yet to be generally feasible). Overall the role of EECA appears to have been to facilitate initiatives that lack an apparent and compelling business case (which electricity users would likely have discovered for themselves) or that give rise to aggregate gains (private and societal) which justify their adoption despite individual parties having insufficient incentive to undertake these themselves.

### *Some Obstacles*

Identifying a potential aggregate demand-side response from the 300 largest electricity users of between 250-900 MW, and estimating a practical target of 400 MW, EECA estimates potential annual savings from such a response of \$10-\$100 million, with an additional saving of \$340 million if the construction of a 400 MW peaking plant could be avoided. At the same time such an analysis suggests a key problem in achieving this response – that of private costs versus public gains.<sup>11</sup> A significant share of the benefits of demand-side participation identified by EECA (see Box 7.1) and the specific gains identified here represent system-wide or third-party gains whose sharing need bear little relation to the specific initiatives undertaken by any one party. Such diffusion of incentives and potential for free-riding presents an obstacle to change. In simplest terms, the most reliable means of ensuring energy users have an incentive to conserve energy is likely to be that they both understand, and get to enjoy, sufficient private benefits from doing so.

As such, the enduring preference for many electricity users for fixed electricity prices over exposure to the spot price presents an important obstacle to change. And while power exchanges are developing for medium and large users, and rebates are available to some such customers during winter power crises (sharing risks and rewards between customers and suppliers), residential electricity customers are yet to enjoy opportunities to resell surplus energy for gain to other parties valuing that energy more highly. Ongoing improvements in metering and communications technology should eventually be expected to lower the transaction costs of small-customer power exchanges, but we are not there yet. Until we do, it will be hard to expect active residential-level power savings and efficiencies on a sustained basis: the cost-benefit calculus does not favour broad adoption at the present time. However, as the Orion experience illustrates, more energy-using households may use alternative fuels and insulation and thereby affect their demand for electricity in the longer term. To achieve this, it is necessary that electricity costs – through prices – are incurred directly by the users of electricity.

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<sup>11</sup> Indeed, EECA's role might be regarded as one of addressing a number of perceived externalities, such as electricity users' lack of information, or the aggregate importance despite individual-level insignificance, of their electricity-consumption decisions.

**BOX 7.1****Benefits and Means of Increased Demand-Side Participation****Benefits:**

- 1) Improved system reliability through reduced demands during emergency situations.
- 2) Reduced wholesale electricity prices (with cost:benefit ratio of 10:1 where “economic”).
- 3) Market efficiency improved when consumers receive price signals and demand more aligned with true costs.
- 4) Energy retailers can reduce their exposure to wholesale electricity prices.
- 5) Environmental benefits from reduced need to use peaking thermal plant, and cost benefits of deferring transmission and distribution enhancements.
- 6) Consumers gain greater control over their electricity bills.
- 7) Market power of generators can be mitigated where it arises from supply shortages or transmission constraints.

**Means:**

- 1) Managing peak loads – reducing load or shifting it to lower-priced times of day.
- 2) Load control – lines companies using ripple control to signal peak loads and/or shed load.
- 3) Instantaneous reserve – grid operator contracts with customers to shed load automatically and at short notice as a means for it to maintain system operation standards.
- 4) Voluntary demand-side participation – allowing consumers, with appropriate price signals, to respond to changing prices by altering demand.
- 5) Other – e.g. power exchanges, self-generation.

Source: EECA (2002b).

*Fonterra and NZAS Initiatives*

Indeed, the importance of the price of energy flowing through to decision-makers and engendering sharper energy management is illustrated by the examples of two companies that consume a great deal of energy (reported in the *National Business Review*, June 2004, as achieving EECA Energywise awards). NZAS reports that 40% of the cost of producing aluminium is attributable to electricity, and that although the company had improved its energy efficiency steadily since its establishment, it assessed that energy in New Zealand would be more expensive than in the past and it changed emphasis from expanding output to “optimising power efficiency”. An extensive internal energy audit precipitated a set of energy projects now underway. Just one of these – one of the most successful projects, involving re-welding all electrical connections through the reduction plant to reduce resistance – is estimated to produce \$1.2 million per year savings on an investment of \$0.6 million.

Similarly, Fonterra Cooperative Group Limited is New Zealand’s dominant manufacturing dairy company. It processes about 96% of New Zealand’s milk, has 4,500 staff and 26 manufacturing sites, and is the second largest user of electricity in the country. It too reports that it has responded to prospectively higher energy prices resulting from the run-down of New Zealand’s prime gasfield, by adopting energy-efficiency programmes. It has identified savings of 8-10% at some existing plants, and considers that it is possible to take these to 15%, or savings of the order of \$20 million per year.

*Firm and Day-Ahead Prices*

In part the ongoing preference of major users for fixed electricity prices over exposure to spot prices reflects their lack of use of alternative energies, and their operational inflexibilities. Plant cannot be shut down or production rescheduled at whim, given technical requirements and/or employment, environmental and customer obligations requiring at least forward notice of any such changes. Research by EECA indicates that commercial and industrial users have capacity to reduce loads, and that they prefer voluntary reductions to interruptible contracts. However, the lack of firm prices being available under current wholesale electricity market arrangements complicates demand-side decision-making, and a useful practical innovation would be the introduction of firm day-ahead electricity prices better allowing users to plan for changes in response to price changes.<sup>12</sup> Complicating the picture further is the fact that only larger users have the resources to acquire wholesale electricity market data and to implement measures to alter demand in response to price changes.

Given such considerations it is no surprise that resorting to exhortation, education and facilitation by bodies such as EECA remains a favoured means for encouraging

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<sup>12</sup> See Counsell and Evans (2003) for a discussion of the merits of introducing a day-ahead market.

greater demand-side participation. Until widespread customer rebates for power savings or power exchanges (and some form of transmission-capacity market) are developed, consumers face no appropriate “carrot” – and, in many cases, not even a “stick” – to conserve or invest in energy efficiency. Indeed, as long as competition and regulatory policies serve to constrain electricity prices, particularly for smaller consumers, EECA will face fundamental conflicts in achieving its goals.

## WHOM TO TARGET?

As noted above, EECA has sensibly targeted its initiatives for encouraging a greater demand-side response at the larger industrial and commercial electricity users. Its data indicate that electricity costs account for 17% of total costs for basic metal producers, and up to 40% for some forestry processors.<sup>13</sup> Such producers and processors can be expected to be acutely aware of the need to economise on electricity demands and otherwise manage their exposure to electricity prices. This too might be suggested for commercial users, representing 22% of total annual electricity demand, but to a lesser extent. For each group, demand-side initiatives should be expected to be (and to a significant extent initiatives undertaken to date have been) both effective and economic.

For domestic consumers, however, who represent around 35% of total annual electricity demand, demand-side initiatives are presently hard to justify on customer-specific economic grounds, but they continue to attract significant political focus. Certainly, domestic consumers account by number for the vast majority of electricity users (indeed, the voting ones), and so a political sensitivity to the plight or progress of this sector can well be understood. On closer examination, however, it is tempting to suggest that such a political and consumer-lobby focus is misplaced, and that the real political-economy pressures lie elsewhere.

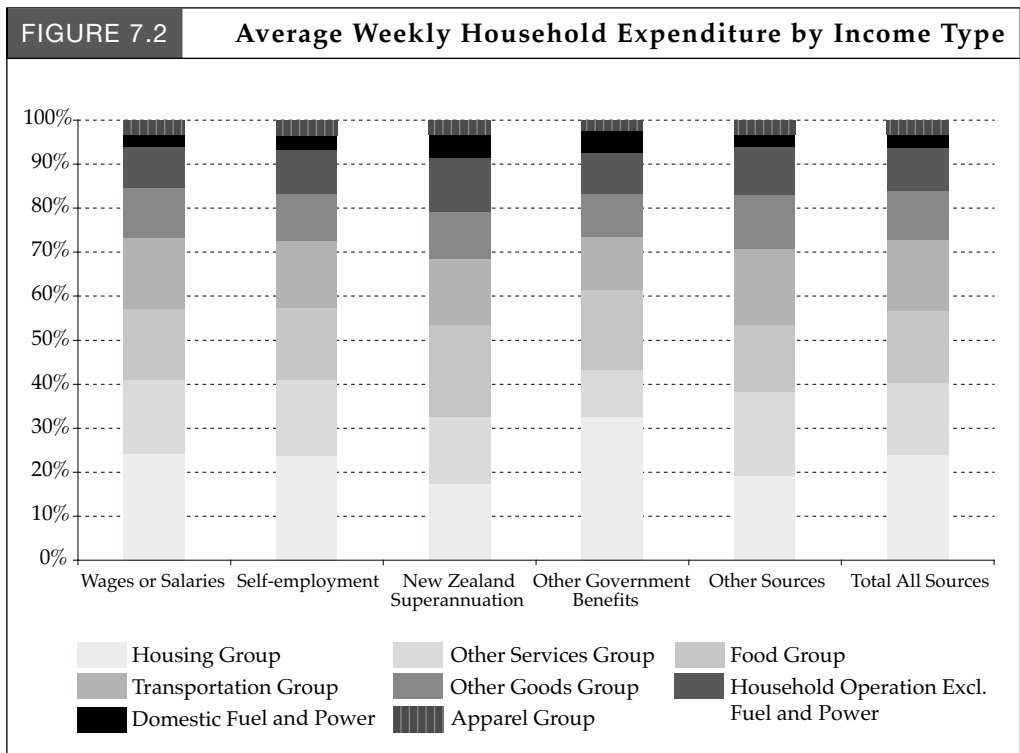
In July 2004 the Government announced its intention to introduce limited price controls into the retail market, by requiring retailers to offer a contract containing a fixed charge of no more than \$0.30 per day for residential users who consumed less than 8,000 kWh per year (the average level of household use). The regulation will also require retailers to provide “equal advertising effort” for such products. The stated aim of this regulation was to address equity concerns particularly for

<sup>13</sup> Indeed, electricity comprises a substantial part of NZAS’s aluminium smelting costs. With NZAS accounting for 15% of national electricity demand, it represents the single-greatest candidate for effective demand-side response, although its long-term electricity supply contracts with Meridian provide it with a temporary measure of protection against wholesale price movements (and temporary closures of pot-lines are very expensive). Encouraging the smelter to turn off just one of its three potlines in the 1992 crisis enabled energy savings of 5%. To the extent that Meridian is exposed to wholesale price movements in future supply crises – e.g. if it is a net purchaser – it might rationally contract with NZAS to reduce its demand in exchange for a share of its avoided wholesale purchase costs.



superannuitants – but many beneficiaries will not be low-income users, many low-income households will not benefit, and it may lead to small price increases for other customers.

As illustrated in Figure 7.2, New Zealand households typically spend around 3% of their total weekly expenditures on electricity (both distribution and energy) and other domestic fuels combined, approximately the same amount that they spend on apparel. By contrast, on items that would more properly be regarded as “essentials” – such as housing and food – households typically spend around 24% and 16% respectively of their weekly expenditure. In the grand scheme of things, power bills account for a negligible share of household expenditures. Even if all households were to implement four simple energy saving measures suggested by EECA, representing a combined 19% saving in total and recognising that water and space heating constitutes 65% of most household power bills, this would shave little more than half a percent off weekly household expenditure, despite reducing annual electricity demand by around 5%.



Source: Statistics New Zealand, 2000-01 Household Expenditure Survey.

A closer look at the official statistics for household expenditures shows that superannuitants and beneficiaries each spend less each week on power and domestic fuel than they do on vehicle ownership expenses. Salaried households (and those living on interest, rents, dividends, etc) spend only slightly less each week on alcohol than they do on domestic energy, and the self-employed spend more on takeaway and ready-to-eat foods. Overall New Zealand households spend slightly less or around the same each week on electricity distribution and energy, along with other domestic fuels, as they do on takeaways, apparel, or overseas travel.

Since any outcries about rising power prices are typically their loudest on behalf of beneficiaries and those on fixed incomes (such as superannuitants), it is fair to inquire into how electricity costs affect their weekly outgoings. The official household expenditure survey statistics reveal that these two groups (reflecting patterns for low-income earners in general) spend 5% of their weekly expenditures on both power and other domestic fuels, more than the 3% figure for groups having other income sources. Once again this figure is small, and compares with much higher expenditure shares for food and housing. For this reason alone the efficacy of the July 2004 regulations, imposing low fixed-tariff options for smaller power users, can be questioned. The data suggest that equity grounds are no proper basis for a fixation with power prices, in either relative or absolute terms.

And even if they were, food suppliers (for example) do not face threats of price regulation, market intervention or, in the extreme, nationalisation – despite the common volatility in food prices (particularly fresh), and the clearly greater share of household budgets they constitute. When food prices rise – for example, and ironically, when it rains too much – any regressive impact this has on lower-income earners and those on fixed incomes is, more properly, treated as a matter of incomes and welfare policies. Food is not singled out as an example of market failure and a need for industry reform. Regulations are not imposed to fix food prices for smaller consumers. It remains curious that the electricity sector, insofar as power prices are a cause for equity concerns, should continue to face such popular and political attention.

It should be emphasised that while residential customers each face little exposure to increases in electricity prices, this is not to suggest that the overall welfare consequences of generator market power or otherwise excessive prices are immaterial. In aggregate they can amount to significant welfare losses, suggesting good reason to consider demand-side improvements at the residential level. Additionally, aggregate residential electricity demand accounts for around 35% of the total, which represents a significant opportunity for savings and avoided need for new generation. The difficulty is that the costs of encouraging a greater residential-level demand-side response – such as new metering or the transaction costs of a small customer power exchange – remain disproportionately high. This is only compounded by the relatively small benefits accruing to individual residential customers should they take the trouble to better manage their electricity consumption and/or invest in alternative fuel technologies or energy efficiencies.

Furthermore, the rebalancing of tariffs in favour of commercial entities over households could just be a reflection of the advantages of concentrated over diffuse interests in political processes. Alternatively, it simply suggests that the households are paying for insurance against short-term swings in electricity prices. Indeed, as a matter of principle, commercial entities are generally held to be less risk-averse than households and better able to manage risk. Thus, the situation we observe of relatively fixed prices for households is in accord with a plausibly appropriate sharing of short-term risk. It need not much affect household investment in longer-term savings through insulation and alternative fuels, because these depend more upon the longer-term direction of prices rather than short-term price fluctuations.

### *A Stocktake*

Considerable cost has been imposed on or otherwise borne by the New Zealand electricity sector in implementing demand-side initiatives aimed at the residential sector – not least the imposed ownership separation of distribution from competitive business activities in 1999 – and such initiatives remain an important focus for government-led industry change. As argued above, for industrial users, and to a lesser extent commercial users, some such measures have had the potential to pay for themselves, and users have had ample incentive and at least some opportunity to undertake the initiatives. Industry, for its part, has not been unresponsive in providing relevant solutions. For the remaining 35% of annual electricity demand, however, increases in electricity prices higher, and maintained for longer, than any observed to date would be required to materially alter residential consumption and encourage energy efficiencies – and thereby to reduce significantly their combined annual energy requirements (in the absence of small customer power exchanges). Since 1996 households have been insulated from short-term fluctuations in electricity prices and, given the current state of affairs, this is not apparently inefficient.

## THE ULTIMATE GOAL?

It must be asked what precisely these initiatives are trying to achieve, and what harm they are attempting to avoid. Certainly a long experience of state-owned and controlled monopoly generation and transmission did not result in a surfeit of electricity customer options – that is to be expected – but is engendering an array of customer choices going to materially alter the lot of small consumers? Alternatively, is the goal to give consumers more options to choose from, or to find better ways to serve their current needs and preferences? While increasing the range of options available to consumers cannot be a bad thing (provided undue costs are not incurred in doing so), what incentives do they have to exercise this choice?

Such questions go to the heart of what really matters to electricity customers. Certainly a competitive, innovative generation and distribution sector resulting in the lowest possible wholesale electricity prices and greatest possible freedom from market power and gaming of industry arrangements is a desirable objective. To the extent that this objective is frustrated by the vertical integration of generation and retailing that has occurred since 1999, a case might be made to force the de-integration of these operators; but for reasons discussed above and expanded on below this might in fact be counter-productive. Straining to give electricity customers greater choice of energy supplier may be neither necessary nor sufficient for materially improved consumer welfare.

Even now the wholesale electricity price directly influences short-term purchasing decisions of only a fraction of the electricity market (despite the potential for it to do so more widely), but arguably with exceedingly good reason. Electricity consumers typically prefer a certain electricity price and ongoing supply security, even when both cannot be simultaneously guaranteed, and are prepared to pay a risk-premium in their electricity price to do so. Much electricity supplied in New Zealand is purchased through long-term fixed-price supply contracts, and there is a conspicuous absence of calls by consumer advocates for small users to be exposed to spot-price-based pricing plans. Only a fraction of consumers are either willing or able to change their short-term consumption patterns in response to wholesale electricity price changes. And even if better arrangements such as a day-ahead electricity market were instituted to allow consumers the choice of responding to price signals by changing their energy consumption decisions, it must be questioned whether they would in fact do so. Given the minimal share of household expenditures represented by power costs, households face limited gains from even 100% energy savings and hence have little incentive to even inform themselves as to energy alternatives let alone respond to price changes.

Conversely, given the considerable spikes in wholesale spot electricity prices that can arise during times of tight supply, smaller customers might be significantly more interested in trading energy savings for profit.<sup>14</sup> Since these profits would in absolute terms easily outweigh the energy cost savings available through conservation and energy efficiency investments (which involve cost) in the normal course, small customer power exchanges offer the most likely means of eliciting a greater demand-side response from residential customers.

As discussed in Chapter 6, electricity users exposed to the wholesale electricity price – typically those with a significant share of their costs represented by electricity costs – face strong incentives to either hedge their price risk, adopt more energy-efficient technologies, or ensure they have the capacity to reduce their demand when spot prices rise (a question of technology as much as contract). Failing such measures, they face the risk of substantial financial costs in the event of such price rises. Only a

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<sup>14</sup> Wholesale prices have demonstrated an ability to increase by factors of around 2,000%, but at most can fall by only 100%.

subset of even large energy consumers are naturally able to bear an exposure to volatile electricity prices – even in the longer term, where switching to more energy-efficient or multiple-energy technologies might be considered feasible.

For smaller customers this is especially so. Except for residential customers building or renovating their homes, most customers have already invested in water-heating, space-heating, cooking and other energy-dependent technologies, and are unlikely to alter these investments even in the face of significant short-term swings in electricity prices. Indeed, many household appliances simply cannot be run except on electricity. While short-term responses to such price swings might involve changes in consumption patterns if consumers were exposed to, or at least aware of, those swings, some research indicates that the responsiveness of demand to price changes is relatively insensitive even when electricity price signals are available.<sup>15</sup> People will still tend to take a shower, cook their toast or boil their kettle in time to get to work, irrespective of the short-term electricity price.

To the extent that most small customers, and even many large ones, have not switched to alternative or multi-energy equipment, changes in energy efficiency technologies and electricity consumption patterns are more likely over the longer-term than the short. For it to be economic for a consumer to install gas appliances rather than electric, for example, they need to see either sufficiently large short-term electricity price spikes or sustained premiums in electricity prices, relative to gas prices, to warrant the high fixed cost of gas installation.<sup>16</sup> Alternatively, they require opportunities to profit by effectively reselling energy savings (e.g. via rebates or power exchanges) – a form of energy recycling from low-value to higher-value uses – when wholesale electricity prices rise. To date these have arisen to some extent.

## CONCLUSION

Encouraging demand-side participation is both natural, and in many cases, desirable. Structural reform to encourage competing generation and retail is an obvious first step, particularly when combined with targeting major electricity users. Indeed, with

<sup>15</sup> Ham *et al.* (1997), for example, discuss experimental research showing that small commercial users are not responsive to time-of-use pricing, although some sub-groups – such as those without electric heating or air-conditioning – show significant responsiveness over short peak periods and with large differences between peak and off-peak prices. EECA has sponsored a trial of demand-side energy management practices on selected commercial and industrial sites, setting out to find if real-time or near real-time access to electricity consumption data can help businesses to reduce electricity costs. Its preliminary findings indicated that savings were indeed achievable, although this should probably be considered a natural consequence of trying. The more telling question is whether it is worth businesses altering their behaviour to reduce electricity costs, which hinges as much on having the capacity to do so expeditiously as it does on the consequences of doing so.

<sup>16</sup> That this formula is accurate can be seen in changing consumer preferences towards energy-efficient motor vehicles following oil price shocks.

competitive generation and retailing, even if vertically integrated, such users have considerable incentive to seek out opportunities to reduce electricity costs themselves, should they have the flexibility to do so, and to bear the costs of doing so. This should mitigate any problems of market power and encourage lower electricity prices; it may also mitigate consumer incentives to save power or invest in energy efficiencies.

The potentially conflicting but desirable alternative is to pursue initiatives that increase the price elasticity of electricity demand. This is at least as much to provide consumers with profit opportunities as it is to achieve cost savings, since the former are potentially much greater than the latter under fixed-price supply contracts. Legislation enacted in October 2004 empowering the new Electricity Commission to regulate the minimum amount of generator output and wholesale purchases covered by supply and other hedging contracts might hinder the delivery of price signals that encourage cost-effective electricity conservation.

The seeming complication is that small electricity users presently are content to insure themselves, in their tariffs, against volatile price levels (e.g. because electricity costs represent such a small share of their total costs, and it is costly to do otherwise), and by design face electricity costs that are relatively fixed (e.g. through hedge contracts or prices fixed by energy retailers). The question is whether the balance of customers and the benefits and costs of demand management by the (typically larger) consumers enable such insurance to be offered at a price that is consonant with risks and rewards in the electricity sector. This can only be discovered by decentralised interaction of the various parties. It is important because in a modern e-economy involuntary interruptions (savings) by any subgroup can yield very large losses in society's welfare.

Notwithstanding the evolution of power exchanges for energy, this remains particularly the case in respect of savings available to transmission and distribution. For as long as most users (if not the larger ones) continue to see bundled electricity charges comprising energy, transmission and distribution elements, and as long as electricity users have no ability to resell transmission savings, a transmission-related demand-side response will be hard to encourage. Internalising the costs of transmission congestion to distributors is likely to be an important first step in remedying this.

Encouraging greater demand-side participation will remain a challenge unless users are persuaded to expose themselves to the true cost of electricity and competing fuels and fuel substitutes, at which point the appropriate balance of risk sharing is struck. Until then the "cajole, inform and facilitate" approach of EECA continues to have some purpose. Ironically, however, this approach represents – in effect – a protracted version of the short and sharp energy-savings campaigns that government no longer wishes New Zealanders to bear in future winter crises, but without the benefit of the urgency and sense of collective responsibility that a crisis creates.

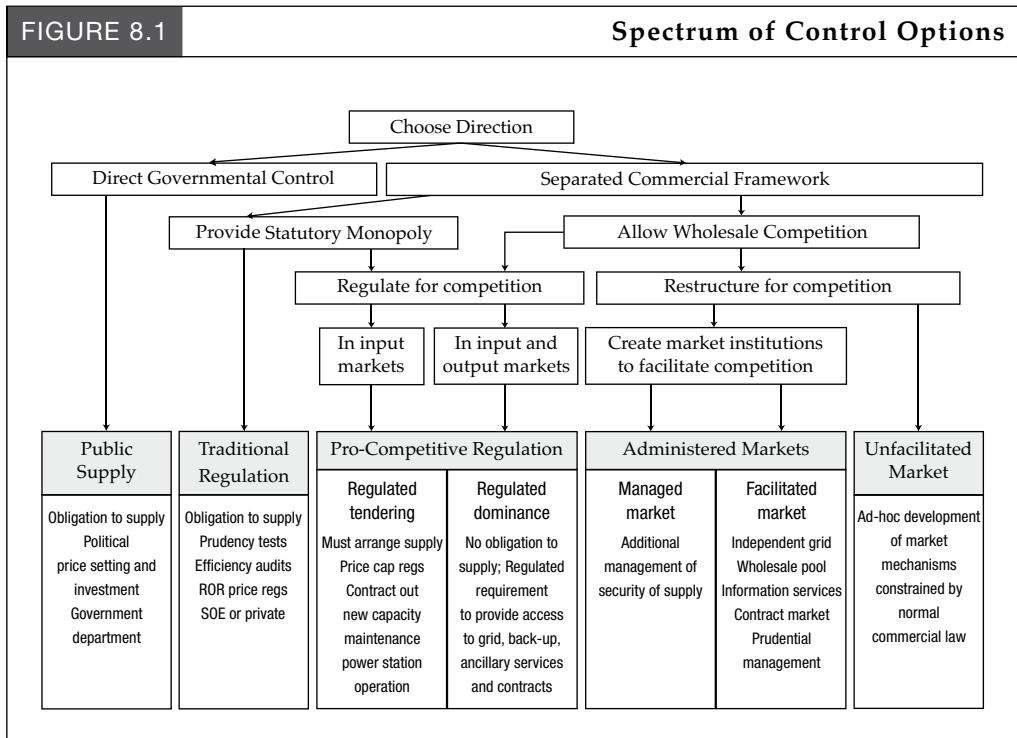
*This chapter begins by briefly recalling the Chapter 4 discussion of electricity reform models used overseas. This provides context for an in-depth discussion of the governance arrangements existing before the contemporary reforms, during the initial reform phases, and more recently. Before unpacking the more recent reforms, we provide a short discussion of what is meant by industry governance. This then leads into a detailed analysis of the wide-ranging reforms introduced in 2001, which were rapidly expanded upon and re-reformed in 2004. We will see that the pace of reform has increased dramatically since 2001, with a few significant revisions, but in the main reverting to centralised industry control by government, through the Electricity Commission. The chapter ends with a brief discussion of grid-security problems arising in 2004, in the context of Transpower's evolving corporate objectives since its inception. Such examples prove to highlight the vulnerability of the centralised approach, cautioning against simplistic belief in centralisation as a panacea to possibly non-existent weaknesses in the decentralised approach. The appendix to this chapter provides background discussions on industry evolution, markets and politics, and recent experience with centralised economic control.*

## INTRODUCTION

Questions of private and government initiative often lie at the heart of industry progress. If an industry is to grow, can its progress be left to private parties or is central or local government intervention required? If an industry is important, can its development be left to market forces, or is the guiding and constraining hand of the state required? Are there questions that the market cannot answer, or answers that government should not be asked to provide?

Hybrids of the centralised and decentralised approach are commonplace. As illustrated in Figure 8.1, options can range from direct government control, through varying degrees of regulation and administration, through to *ad hoc*, unfacilitated market development at the other extreme.

For the past two decades New Zealand has shifted from very considerable centralised control of most areas of economic activity (up until 1984) to a greater level of decentralised control, allowing and requiring industries to largely chart their own course subject to general constraints and policy goals. As we shall see below, recent reforms in the New Zealand electricity sector reflect a clear reversion to centralisation.



Source: Wholesale Electricity Market Study (3, 1992).

## CENTRALISATION AND DECENTRALISATION IN THE NEW ZEALAND ELECTRICITY SECTOR

### *Recent International Context*

As discussed in Chapters 2 and 4, the physics and economics of electricity provision through interconnected AC networks, and monopoly concerns surrounding electricity provision (whether “natural”, as for transmission, or accidental, as for nationalised generation), have both resulted in a historical bias towards centralised control. In the US private ownership of monopolistic, centralised, vertically integrated electric utilities, balanced by heavy-handed regulation, has long been the dominant model. In other countries or states such as New Zealand, Australia, and England and Wales, government ownership and control have been the norm. To varying degrees reforms in such electricity systems have tested the boundaries of what does or does not require centralised administration.

Many reforming jurisdictions have been relatively cautious in implementing reform, opting for centralised electricity markets and significant ongoing input by government



regulators – often with widespread electricity privatisations (e.g. Victoria). England and Wales opted first for this model, but then for the alternative extreme of highly decentralised markets but strong regulatory intervention as well. PJM in the US began with local privately owned monopolies, and has been transformed into a voluntary interconnection across states relying on highly decentralised markets. New Zealand has charted a different course that has involved strong government involvement at times and ongoing state ownership in the main, little regulatory intervention except through ownership, a mainly centralised electricity market, but otherwise decentralised industry control. As we shall see, only lately has it traded the latter for significantly increased regulatory intervention. In terms of Figure 8.1, this moves us from a facilitated market approach to one more based around traditional regulation.

The important lesson from these experiences – especially under NETA, PJM and other jurisdictions with mainly decentralised electricity markets – is that technical coordination questions (other than real-time grid management) do not require centralised control. Indeed, the PJM and Australian NEM experiences suggest that even problematic areas such as grid management and expansion can and are achieved with appropriate frameworks for private parties to operate within. Experience would tend to belie the necessity of centralised control of electricity systems' operation.

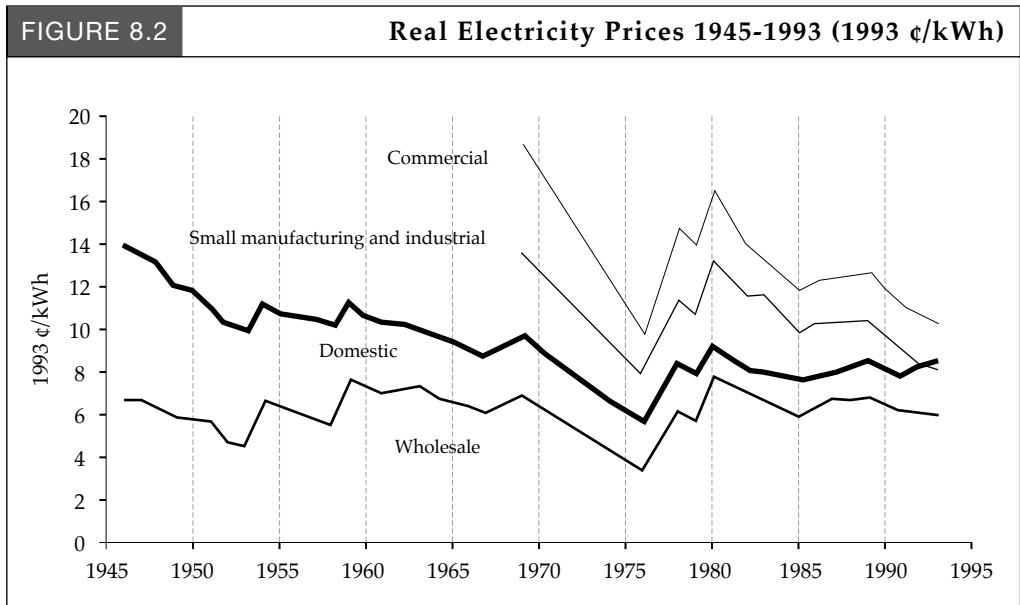
#### *Early Decentralisation Short Lived*

As noted previously, New Zealand's electricity sector began as decentralised initiatives by either private parties (e.g. for industrial processes) or by private parties in association with local government (e.g. for street lighting). Once central government assumed control of the nation's hydrological resources and embarked on a process of nationalising generation assets, building generation, and constructing the national transmission grid, the result was functional and administrative centralisation of much of the electricity system. Perhaps deterred by local-government reluctance to allow locally developed distribution assets to become part of the national asset, electricity retailing and distribution remained a decentralised aspect of the system.

#### *Market Solutions Supplanted by Government*

With such centralisation it became largely inevitable that non-market-based solutions would be applied to the operation and function of core parts of the electricity sector. While a handful of industrial companies were able to negotiate direct supply contracts with state-owned and -controlled generation and transmission, electricity pricing and investment decisions had fallen within the purview of government – subject to any lobbying pressures that electricity supply authorities (ESAs) or these other industrial users were collectively or individually able to bring to bear, or subject to broader political considerations (such as containing inflation or influencing economic growth). An independent centralised electricity market was not a realistic prospect under such arrangements. The Minister of Energy would announce increases in the electricity Bulk

Supply Tariff (BST), bundling energy and transmission charges, at the annual ESA industry conference. That electricity prices under centralised control can be volatile – and exhibit major “step” jumps that belatedly reflect changed circumstances of all sorts than usefully presage supply and demand imbalances – is amply demonstrated in Figure 8.2.



Source: Wholesale Electricity Market Development Group (1994).

Within government a degree of decentralised operation and control of the electricity system along broadly geographic lines persisted for a time, but centralisation continued with the formation of the Electricity Division of the Ministry of Energy in the 1970s. Throughout this period control of the sector lay with a government minister who, under the Electricity Act 1968 (as amended), was authorised to “acquire, construct, operate, and maintain, any works for the generation of electricity, and generally to carry on the business in all its branches of the sale and supply of electricity”. Furthermore that Act prohibited any party from supplying electricity, constructing or using electric lines, or generating electricity using water except as authorised by the Minister on whatever terms he saw fit.<sup>1</sup> Electricity prices under this legislation were set to ensure recovery of the costs of running and maintaining the system, but not all capital costs (i.e. the system was not self-sustaining).

<sup>1</sup> In the case of hydro generation such terms specifically included provision for a water rental set by taking account the cost of alternative sources of energy, in effect a de facto market price of water. As discussed in Chapter 6, rising wholesale electricity prices when hydro storage levels are falling provide a contemporary proxy for such a price.

## BOX 8.1

## Ministry of Energy under the Electricity Act 1968

**An Act to consolidate and amend certain enactments relating to the generation and sale of electricity . . .****Principal functions of the Ministry of Energy:**

- 1) to initiate, organise, co-ordinate, continue and maintain the production, transmission, and supply of electricity;
- 2) to encourage the development and improvement of systems of supply of electricity;
- 3) to seek to ensure standards of safety, efficiency, and economy of operation in respect of the production, transmission, and supply of electricity;
- 4) to carry out surveys in respect of the supply and use of electricity;
- 5) to advise government departments on all matters affecting electricity;
- 6) to carry out such functions in respect of and incidental to the production, transmission, and supply of electricity as the Minister may from time to time direct.

**Ministry of Energy to exercise its functions and duties as fully and adequately as may be necessary to satisfy the need for electricity within New Zealand and carry out the purposes of the Act, including 7(2):**

- 1) undertake or provide for: (i) the generation, purchase, or exchange of electricity; (ii) the distribution of electricity in bulk to electricity supply authorities; (iii) the direct supply of electricity to large consumers; (iv) the retail supply of electricity to consumers;
- 2) arrange or execute: (i) a continuous programme of works providing adequate supplies of electricity; (ii) the supply of electricity at the lowest practicable cost;
- 3) promote: (i) the use of economical methods of generating, transmitting, and distributing electricity; . . . (v) the simplification of methods of charge for supplies of electricity; (vi) the avoidance of wide variations in charge for supplies of electricity;
- 4) regulate, control, allocate, and (wherever in the opinion of the [chief executive] it is necessary) restrict or prevent the use of electricity;
- 5) undertake or promote measures to achieve greater economy and efficiency in the use of electricity as a means of reducing the future rates of growth of electricity requirements.

This state of affairs continued until the dissolution of the Ministry and creation of the Electricity Corporation of New Zealand (ECNZ) as a stand-alone commercial and ostensibly independent state-owned enterprise (SOE) in 1987 under the State Owned Enterprises Act 1986. While operationally this innovation represented a measure of decentralisation by attenuating the hitherto direct and overt political influence over the sector, it did not and could not remove the ongoing political incentive to remain involved in the sector, and therefore resulted in a persistent tension between ECNZ and its government shareholders.<sup>2</sup>

Even with the separation of Transpower from ECNZ – functionally through the unbundling of transmission and wholesale energy charges in 1993, and legally by its creation as a stand-alone SOE in 1994 – the centralised model persisted in the form of state-owned monopolies. The pricing and investment policies of the now-separate generation and grid companies were the responsibility of their respective and ostensibly independent boards, and in each case no formal market mechanism for their determination or guidance were in place. Changes in each were a result of fiat or bilateral negotiation with industry representatives. While this situation changed for generation with the creation of the NZEM and break-up of ECNZ, it persists for transmission, even though Transpower's centralised decision-making powers regarding grid pricing and investment have now passed from it to the new Electricity Commission (more later).

In its earlier years the real price of electricity was significantly reduced by ECNZ, falling 12% in real terms in ECNZ's first four years of operation. As discussed in Chapter 5, however, when ECNZ attempted to raise prices in 1991 the limits imposed under the SOE Act 1986 on political influence over electricity pricing faced (and failed) their first test. While government did not formally force ECNZ to resile from its announced price increase, its response was such that the board of ECNZ recognised that it faced a critical political face-off, and elected to revise its proposal. In effect it accepted that pricing policy – and hence investment policy, which hinged on expected future returns – would require political sanction.<sup>3</sup>

It is interesting to note that even before this political show-down ECNZ held a view regarding long-term electricity prices that proved to be misplaced. As summarised and discussed in Chapter 5, in 1991 ECNZ predicted electricity price-ranges based on long-run marginal costs for various types of new generation that all exceeded actual market outcomes under the New Zealand Electricity Market (NZEM, which commenced full operations in October 1996). While this might be said to reflect the benefits of competing generation, which arose in 1996 with the first step in ECNZ's successive break-up, it should be noted that competition was predicted to produce prices at a level of such long-run marginal costs to support ongoing investment in generation. That ECNZ, as the then centralised controller of generation and transmission (and having the best

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<sup>2</sup> A detailed and engaging account of the history of these tensions is given in Chapter 16 of Martin (1998).

<sup>3</sup> See Martin (1998) and Fernyhough (1993).

## BOX 8.2

## Key Provisions and Principles of the SOE Act 1986

**An Act to promote improved performance in respect of government trading activities ...****Part I – Principles, including:**

- 1) The principal objective of every state enterprise is to operate as a successful business and, to this end, to be as profitable and efficient as comparable businesses that are not owned by the Crown . . .
- 2) All operating decisions of a state enterprise to be made by or pursuant to the authority of its board of directors in accordance with its statement of corporate intent (SCI, a document covering a range of matters adopted by the board after considering any comments by the relevant shareholding Ministers on its draft SCI).
- 3) Where the Crown wishes a state enterprise to provide goods or services to any persons the Crown and state enterprise are to contract for this with the Crown paying all or part of the price thereof.

**Shareholding Ministers may direct a state enterprise board on the kinds of matters covered in its SCI after consulting with the board and having regard to the Part I principles.**

**Set of principles for state-owned enterprises:**

- 1) Responsibility for non-commercial functions will be separated from major trading state-owned enterprises.
- 2) Managers of state-owned enterprises will be given a principal objective of running them as successful business enterprises.
- 3) Managers will be given responsibility for decisions on the use of inputs and on pricing and marketing of their output within the performance objectives agreed with Ministers so that managers can be held accountable to Ministers and Parliament for their results.
- 4) The advantages and disadvantages that state owned enterprises will have, including unnecessary barriers to competition, will be removed so that commercial criteria will provide a fair assessment of managerial performance.
- 5) Individual state-owned enterprises will be reconstituted on a case by case basis in a form appropriate for their commercial purposes under the guidance of Boards comprising, generally, members appointed from the private sector.

*Source:* State-Owned Enterprises Act 1986, and Statement to the House of Representatives, Hon R. O. Douglas, Minister of Finance, 12 December 1985, in David Butcher & Associates (2002).

possession of relevant production cost data), should significantly mis-estimate future electricity prices also highlights the pitfalls of centralised forecasting and presages the problem of centralised markets acting on a single view of the world.<sup>4</sup>

#### *Origins of the Wholesale Electricity Market*

Electricity pricing policy was once again political as well as centralised. Ironically, however, it was this episode that spawned the creation of the centralised but independent wholesale electricity market. Initially this involved little more than ECNZ posting a “spot price” for half-hourly electricity supply weekly in advance, which was relevant only to the extent that ESAs needed to make up any shortfall (or trade any surplus) in electricity purchased from ECNZ under long-term supply contracts. Additionally, however, it resulted in the industry-led development of a true wholesale electricity market, if only as a device for ECNZ to regain some measure of freedom from political involvement in its pricing (and hence investment) policy.<sup>5</sup>

While ECNZ remained the all-but-sole generator in New Zealand, it could not be expected that a true wholesale electricity market offering prices determined according to competitive processes could arise. However, with the break-up of ECNZ – initially by the spin-out of Contact Energy from ECNZ in 1996, and the company’s further break-up into Genesis, Meridian Energy and Mighty River Power in April 1999 – as well as the entry of new generators into the sector, electricity pricing policy was no longer centralised in the hands of ECNZ (or government). Competing state-owned generators now vied with each other and also with privately owned generation for business not covered by long-term supply contracts through an independent centralised market, the NZEM.

Wholesale electricity prices were now determined through the operation of this market, with the all-important market rules that governed the electricity price-setting process being determined multilaterally by industry participants and enforced separately by a Market Surveillance Committee independent of industry.<sup>6</sup> Although participation in the NZEM was voluntary, its industry-led formation was reflected in its usage, with 80% of energy produced passing through the new market.<sup>7</sup> The remaining

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<sup>4</sup> Market prices, by contrast, represent a means of aggregating diverse price expectations of multiple market participants, reflecting their private information and assessments (on which their actions will be based, resulting in a measure of self-fulfilling prophecy). As noted in *New Zealand Electricity Market (2001)*, it is possible for legitimately wide variations in such expectations, and so it is perhaps no surprise that centralised forecasting – particularly of variables determined by the actions of others based on their own assessments – might be so inaccurate. Decentralised price formation diversifies the risk of forecast errors.

<sup>5</sup> See Martin (1998) or Boshier and Gordon (1996). It also offered a hedge against ECNZ’s break-up, since it facilitated entry by competing new generation.

<sup>6</sup> See Arnold and Evans (2001). The separation of rule-making and enforcement roles avoids potential conflicts arising when regulators or others are responsible for both.

<sup>7</sup> While 80% of energy produced in New Zealand passes through the wholesale electricity market, much of this is hedged by industry participants – for example, through contracts for differences under which supply prices are effectively fixed at negotiated levels.

20% of energy supplied in New Zealand continued to be provided under bilateral contracts, with the industry once again agreeing among its own members rules for measuring and reconciling energy supplies and off-takes irrespective of whether they were traded bilaterally or through the market (MARIA).<sup>8</sup> These rules also facilitated customer switching between power companies. A further devolution of rule-making power occurred with the industry assuming responsibility from Transpower for setting common quality and security standards for operation of the grid (MACQS).<sup>9</sup>

### *An Unintended Consequence?*

Curiously, it can be argued that the ongoing political involvement in the New Zealand electricity sector over the course of the contemporary reforms itself led to an unintended further devolution of industry away from state control to self-determination. Momentum for this development was provided by the ongoing tension between government and SOEs created by the SOE Act 1986 – a tension inherent in the half-way house between private and public ownership. Ongoing state involvement remains dominant through the state’s ownership of transmission, most of generation, and now also most of energy retailing (a form of *de facto* nationalisation arising when state-owned generators formed in the 1999 split of ECNZ began a process of acquiring existing retailing operations and customer bases put into play after the 1998 legislation that required ownership separation of lines and energy businesses). But this involvement has, until recently, been moderated by the industry-led creation of the wholesale electricity market and the other initiatives regarding metering reconciliation and grid quality and supply security standards.

As discussed in Chapter 5, the Electricity Industry Inquiry in 2000 was commissioned to evaluate whether industry arrangements were adequately meeting government objectives, albeit without any clear indication that they were not. Without presenting a clear rationale the inquiry recommended the merging of existing industry self-governance arrangements – NZEM, MARIA and MACQS – and recommended industry be invited to achieve this and various other objectives. The broad nature of the governance structure was not one that followed the dictum of Occam’s Razor, in which compulsory governance is limited to that which was absolutely necessary to enable operation of the system. Given vagueness in the governance of state-owned entities and other factors mentioned in Chapter 5, it was never likely that industry would be able to implement the politically required governance, at least not in the provided timeframe, and so government threats to impose the required solutions in the absence of industry agreement can be argued to have simply foreshadowed a

<sup>8</sup> Metering and Reconciliation Information Agreement, created in 1994, setting metering and information standards so grid-wide electricity flows can be reconciled.

<sup>9</sup> Multilateral Agreement on Common Quality Standards, created in 1999, shifting responsibility for determining common quality and supply security standards to the industry, thereby allowing grid users collectively to determine price/security trade-offs and reducing the potential for Transpower to use supply quality as a means of exerting market power.

foregone conclusion. It is therefore little surprise that a new Electricity Commission was created by government, and on 1 March 2004 assumed responsibility for industry governance. Earlier attempts by industry to foster and preserve its independence have now been superseded.

## THE ROLE OF GOVERNANCE

### *What is Governance?*

Having its origins in the Latin for “steering a ship”,<sup>10</sup> the plain dictionary sense of the term “governance” refers to conducting the policy and affairs of a state, organisation or people, or otherwise to controlling or influencing.<sup>11</sup> In the context of individual companies it typically refers to “the structure through which the objectives of the company are set and the means of attaining those objectives and monitoring performance are determined”,<sup>12</sup> significant aspects of which are set out in companies law. With respect to state-owned enterprises (SOEs) in New Zealand, it also includes consideration of the particular mechanisms created under the SOE Act 1986 to place such enterprises on a stand-alone commercial footing, and so at arm’s length from political involvement in operational decisions.

### *When Governance is Relevant*

In contexts where conflicts of interest between parties do not naturally arise, questions of governance become irrelevant. For example, in owner-operated companies relying on internal funding there is little scope for the owner (or other financiers) to be rorted or otherwise disadvantaged by the operator. Similarly, where an industry comprises competitive operators not reliant on shared resources (such as a distribution network) or other industry-specific features such as a dedicated exchange for inputs or outputs, there is little need for rules to co-ordinate or otherwise govern the balance of cooperation and competition of that industry – apart from general laws such as those relating to commerce, employment and the environment.

Various industry characteristics can, however, give rise to issues of governance. They include requirements to coordinate shared resources (e.g. a grid), to agree or standardise industry arrangements (e.g. technology protocols), or to jointly undertake industry-specific investments that would otherwise be uneconomic or impossible to implement (e.g. research programmes).<sup>13</sup> Such characteristics give rise to questions about the basis on which these matters are addressed, and how that basis is monitored,

<sup>10</sup> Farrar (2001).

<sup>11</sup> *Concise Oxford Dictionary*.

<sup>12</sup> OECD (1999).

<sup>13</sup> The usual economic culprits in this regard are economies of scale, informational asymmetries, or “hold-up” or “free-riding” problems. See, for example, Evans and Quigley (1998).



enforced and modified. In this light it makes sense to ask what governance might mean for an electricity industry, sharing as it does an interconnected transmission and distribution network reliant on specific operating rules and standards, exchanging its outputs through a centralised market or via decentralised bilateral trades, and requiring information sharing to reconcile ephemeral supplies and demands. As discussed earlier, the physics and economics of electricity networks do indeed present particular interdependencies that complicate electricity industry governance, but this does not necessitate centralised control as a consequence.

### *Governance and Competition Laws*

Having said this, “industry governance” has been a relatively unfamiliar term in New Zealand over the past two decades. With the Commerce Act 1986 being the fundamental source of competition law and, until recently, relying on a general regulatory regime, direct government regulation of specific industries has been a waning force in industry governance. At the same time, attempts at industry coordination in New Zealand have risked falling foul of the Commerce Act 1986 – section 27 of which prohibits contracts, arrangements or understandings having the purpose or effect of substantially lessening competition in a market. Accordingly, to the extent that any given industry is governed or otherwise acts in a coordinated fashion, great care has been required to avoid the appearance or fact of anti-competitive behaviour (or unless there was explicit exemption from this provision, such as with dairy industry restructuring).

That the electricity industry in New Zealand has been successful in instigating and implementing industry-wide initiatives – NZEM, MARIA and MACQS – tends to suggest that it has collectively encouraged greater competition in the sector, or at least avoided a substantial lessening of competition. Such a feat is easily contrasted with a worldwide history containing industry-led endeavours designed to achieve the very reverse (not least in the US industry in the early 1900s – see Chapter 4). As such, the objectives of the contemporary reforms as expressed by their political instigators as far back as the 1980s would appear to have been embraced by the very parties subject to those reforms. Recent government moves, however, indicate that an alternative course is now to be pursued.

### *Early Governance in the Reformed Electricity Sector*

It is in this sense that electricity industry “governance” first derived its contemporary meaning. The rules of the wholesale electricity market (NZEM), agreements for metering and reconciling energy flows (MARIA), and the formation of common quality and security standards (MACQS) individually and collectively constitute governance arrangements. Being multilateral voluntary agreements by industry participants who will be bound by self-defined rules affecting key aspects (both centralised and decentralised) of the industry’s operation, they are examples of self-imposed regulation intended to satisfy industry, consumer and political aspirations for the sector while avoiding potential harms that might otherwise attract government intervention.

*New Electricity Commission*

Prior to the 2000 Electricity Industry Inquiry there was no natural inclination on the part of industry to merge the three industry governance arrangements, the voluntary NZEM, MARIA and MACQS. A start was made, on grounds of cost, but there was no natural fit in terms of voluntary-involuntary requirements to amalgamate NZEM and MARIA governance. Around 20% of electricity in New Zealand was being supplied by bilateral contracts, freely entered into, presumably by buyers and sellers content to trade outside of NZEM rules. But, as discussed in Chapter 5, the Inquiry and subsequent government moves, with or without making a case for merger, placed this reform on industry's agenda.

At the centre of this reform was the creation of an Electricity Commission charged with a wide range of industry responsibilities that overlapped with those of existing industry participants. In effect this Commission bears a striking resemblance to the Electricity Division of the Ministry of Energy, the body disestablished by the reform process begun in the 1980s. Government regards the industry as having inadequately responded to various policy and climatic challenges. It has concluded (perhaps despite history) that a politically determined and centrally controlled solution, in substance if not legal form, is the most appropriate model.<sup>14</sup>

It is from an inspection of the new Electricity Commission's roles that future electricity industry "governance" takes its definition. Specifically, the Commission is "to govern the electricity sector and to take primary responsibility for achieving the government's policy objectives for electricity".<sup>15</sup> While the government's overall objective for the electricity sector is not especially different from that of its predecessors, it is seeking a number of specific outcomes consistent with its overall objective – and these in at least one respect mark a material departure from past arrangements. Foremost is its desire that risks (including price risks) to security of supply are "properly and efficiently managed", as opposed to being left to industry to resolve, by the Commission being required to use reasonable endeavours to ensure a 1-in-60 dry-year supply security without a need for voluntary energy saving campaigns (as discussed in Chapter 6).

The government retains the goals of sustained downward pressure on electricity costs and prices, reduction of entry barriers to the sector, and signals to investors and consumers of the full costs of producing and transporting additional units of energy. However, its desire that the new supply security goal be achieved in a manner minimising undesirable distortions to the normal operations of the wholesale electricity market, and

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<sup>14</sup> In January 2004 the government reinforced this message, with the Minister of Energy commenting on proposed retail electricity price rises (as it happens, endorsing the increases); the media also reported that price controls would be considered if such price rises were to be repeated next year. Such comments relate to competitive energy retailers (i.e. not monopoly lines businesses), and to privately owned concerns as well as SOEs.

<sup>15</sup> Government Policy Statement on Electricity Governance, September 2003.

that investment incentives in the sector are maintained and do not discriminate between public and private investment, would appear to be an acknowledgement that its reform initiatives are likely to involve some important trade-offs (and indeed, conflicts).<sup>16</sup>

### *Governance Role Expanded to Management*

Governance, under the Electricity Commission, is now to cover matters as diverse as pricing and clearing functions, regulation, oversight, monitoring market participants, direct involvement in information gathering and provision of supply and demand, security of supply, the wholesale market, generation, transmission, distribution, and retailing. Under such headings are the need for specific arrangements such as setting minimum hydro levels for security of supply (formerly an operational decision of hydro generators subject to general environmental and resource management law), transmission investment and pricing (formerly the responsibility of Transpower), setting grid-security standards (formerly the industry's responsibility under MACQS) and lines company pricing options (formerly such companies' operational responsibility) with low fixed-charge plans being mandated. Moreover, under the 2001 Act every person involved in developing rules or standards applying to electricity industry participants was made accountable to the Commission and required to comply with objectives and outcomes set by the Minister of Energy. Governance thereby came to mean the centralised planning, management and administration of the electricity sector – not just the process whereby its rules for management and development were determined and implemented on behalf of its members.

### *Minister Has Effective Control*

Importantly, key operational decisions at the heart of industry progress are now centrally determined by the new Commission, consultation requirements notwithstanding.<sup>17</sup> More fundamentally, however, the Commission itself was to be a creature of the Minister of Energy.<sup>18</sup> Under the Electricity Amendment Act 2001 the Commission is to be appointed – or its members removed – by the Minister (Schedule 2A), not by industry. The Commission is accountable to the Minister (section 172U) – not industry. The Minister was not bound under the 2001 legislation by any of the Commission's recommendations (section 172Z) and could direct the Commission (section 172ZA). In short, if the Commission was not formally a proxy of the Minister of Energy, the risk was that in substance it would be.

<sup>16</sup> See Morrison & Co. (2003) for an elaboration of the conflicts arising under the reserve generation mechanism.

<sup>17</sup> Section 172Y of the Electricity Amendment Act 2001 requires the Commission to consult with persons whom it or the Minister of Energy considers are representative of the interests of persons likely to be affected by any proposed regulations, clearly affording either party significant discretion in its consultation choices and apparently side-stepping the usual right of parties affected by regulations to be heard and to seek judicial review where they are not.

<sup>18</sup> Indeed, there are even a number of matters the Minister of Energy may determine without reference to the Electricity Commission – see section 172F of the Electricity Amendment Act 2001.

### **Powers for Electricity Industry Regulations**

Section 172B (Low Fixed Charge Tariff Option for Domestic Consumers) – power to regulate for low fixed tariff option for domestic consumers.

Section 172C (Regulations for code on access for beneficiaries of customer and community trusts) – power to regulate to promote accountability of community and customer trusts to beneficiaries.

Section 172D (Electricity governance regulations for wholesale market and transmission of electricity) – power to regulate: for establishment and operation of wholesale electricity market, and to require participants in such markets to comply with provisions; to prescribe reasonable terms and conditions for grid connection, regulate grid expansions, replacements or upgrades and allocation of associated costs; setting grid quality and security standards; and grid pricing policy.

Section 172F (Other electricity governance regulations) – power to regulate re: complaints resolution system; prepayment meters; ability of consumers to choose preferred electricity retailer; transition arrangements for insolvent electricity retailers; connection of generation to distribution lines; hydro spill; hedge price disclosure; dispute resolution; and enforcement of electricity governance regulations.

Section 172H (Electricity governance rules) – Minister may make rules (subject to regulations) for all or any of the purposes for which an electricity governance regulation may be made.

### **Governance of Electricity Industry**

Section 172L – purpose is to enable establishment of Electricity Governance Board (EGB, i.e. Electricity Commission) that is to:

- 1) be responsible for developing recommendations on electricity governance regulations or rules that promote its principal objective (i.e. section 172N – to ensure that electricity is generated, conveyed, and supplied to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner) and other functions (section 172O); and
- 2) ensure the accountability of electricity governance organisations (EGOs, i.e. any person involved in developing rules or standards applying to any industry participants).

## BOX 8.3 CONT'D

## ... Electricity Amendment Act 2001 – Key Elements

EGB must consult with persons that it or the Minister thinks are representative of the interests of persons likely to be substantially affected by proposed regulations (section 172Y), but is accountable to the Minister (172U; member and EGB duties set out in sections 172S and 172T respectively), who is not bound by the EGB's recommendations (section 172Z) and who may direct the EGB (section 172ZA).

Governor General may by Order in Council regulate (section 172ZE) for payment to Minister of levies from industry participants (section 172ZC).

Minister must set objectives and outcomes that EGOs are to pursue re industry governance and against which EGOs must report and be examined in accordance with (section 172ZK); EGOs must agree annual performance standards with the Minister (section 172ZL) and provide Minister with annual performance reports (section 172ZM).

New Schedule 2A inserted regarding EGB and EGB's board, including Minister's powers of appointment and removal of EGB members.

Source: Electricity Amendment Act 2001.

Lacking the independence of other major government bodies such as the Commerce Commission, at the very least the Commission will seek to operate closely with the Minister for fear of taking a mis-step, or face a constant need to second-guess what activities or proposals are likely to be acceptable to the Minister. Not only has the industry's operational independence been subsumed by the Electricity Commission, but the Commission's power effectively lies with the Minister, and that power itself is not as clearly circumscribed as is the case in other industries. It must be asked whether even the pre-1987 Electricity Division of the Ministry of Energy was as beholden to its Minister as the Electricity Commission appears to be. It remains to be seen whether the new arrangements will preserve a central role for the wholesale electricity market, or whether the market becomes a side-show to an industry significantly centrally planned (in substance if not form). Already new generation capacity is being used to constrain short-term wholesale electricity price rises. While much of the electricity system remains in state ownership, measures such as these clearly affect the operations and prospects of both these SOEs and private or community- or customer-owned companies.

#### *Price Controls Also Imposed*

A parallel development to the establishment of the Electricity Commission was the 2001 amendment of the Commerce Act 1986 to effectively activate price-control provisions latent in that Act and to make specific provision for the application of price

controls to electricity lines businesses and Transpower.<sup>19</sup> Under these provisions the Commerce Commission has promulgated price-control measures for lines companies and Transpower based on the CPI-X model common overseas as a means to address any issues of market power arising in these parts of the industry.

Pending the Electricity Commission's determination of its investment programme, Transpower was in December 2003 assigned a value for X of 1%, meaning its overall revenue for the next year is capped at the rate of consumer price inflation less 1%, while responsibility for its pricing methodology has also been taken from its board and assumed by the Electricity Commission. For lines companies, X has been set at either -1%, 0%, 1% or 2% depending on their assessed relative efficiency and profitability. While the Commerce Commission is formally and operationally independent of the Minister of Energy (and indeed of its own minister, the Minister of Commerce), the significant amendments recently made to the Commerce Act indicate that the relatively "light-handed" regulation of New Zealand's electricity sector, which characterised much of the previous 20 years of reforms, is a thing of the past. It now appears that the hand of government is firmly on all aspects of the sector.

### *Conflicting Roles*

To complicate matters further it would appear the new Electricity Commission will be assuming functions that have potential for inherent conflict: the Commission will be responsible for policy, regulation, monitoring, and pricing and investment decisions, as well as being a market participant in its own right. The potential for conflict would also appear to extend to other areas of government domain, including competition, insolvency, environmental, and consumer law. The Electricity Commission represents a shift in power within government, not to mention between industry and government.

### *Electricity and Gas Industries Bill 2003*

These relatively recent reforms, significant as they were, were rapidly re-reformed. Omnibus legislation was introduced into parliament in October 2003 (and enacted in October 2004), not only building on and in some cases amending the 2001 electricity reforms, but also extending similar reforms to the New Zealand gas industry.<sup>20</sup> The legislation amended the Electricity Act 1992 (and also the Electricity Amendment Act 2001), Electricity Industry Reform Act 1998, Commerce Act 1986, and Gas Act 1992 (including a new subpart providing for imposed industry governance by a new Energy Commission). Without a clear rationale being offered for doing so, New Zealand has moved towards the regulatory model adopted in England and Wales, under which the gas and electricity industries fall under the auspices of a combined regulator.

<sup>19</sup> Commerce Amendment Act 2001 and Commerce Amendment Act (No. 2) 2001 respectively.

<sup>20</sup> When the gas industry was warned – as the electricity industry had been previously – that the government expected it to make its self-governance arrangements conform with government policy or government would do so for it, one industry executive publicly asked what problem it was supposed to be fixing.

Significant provisions in the amending legislation included an extension of the definition of industry participant to include wholesale electricity purchasers (only retail customers are to remain outside of industry control), reserve generation provisions including powers to compel electricity supply and the terms of such supply, and a raft of other ministerial regulatory powers. These powers delve deeply into operational matters, providing for electricity-generation regulation and management of supply and price risks (including reserve fuel and capacity management, tendering of minimum volumes of supply and other hedge contracts, and information disclosures). Similarly, wholesale electricity purchasers can be compelled to maintain minimum levels of hedge coverage (which presumes sufficient contracts are available), and minimum levels of demand-side management and interruptible load (which suggests electricity consumers might be compelled to suffer supply interruptions beyond the simple ripple control of water-heating common before the reforms). Perhaps mindful that such interventions have the capacity to increase the risk of retailer failure, provision was also made to regulate for arrangements in the event of retailer insolvency.<sup>21</sup>

In some respects the amendments unwound some of the more problematic provisions already enacted in the 2001 legislation. Electricity Governance Organisations (former sections 172L, 172ZK, 172ZL, 172ZM), for example, are now not to be subject to ministerial objectives and outcomes, performance standards and reporting. The Minister of Energy is to be precluded from recommending regulations unless the Electricity Commission has first made a recommendation, and ministerial powers to amend the Commission's recommendations are to be limited. The Commission is no longer required to consult with the Minister of Energy before making recommendations, and the prohibition in the 2001 legislation on the courts finding a regulation to be invalid because of inadequate consultation has been removed (subject to a six-month grace period). These improvements to the governance of the Electricity Commission must be welcomed. However, the significant expansion of the Commission's regulatory powers again represents a further shift towards centralised planning and control of the New Zealand electricity sector.

### *Goal Posts Shifted*

The electricity industry "goal posts" have been significantly shifted. Until these recent reforms, government was clearly involved in setting the macro agenda for the electricity sector and not above legislating for changes where it saw intransigence or delay on the part of industry in achieving its objectives. While the impacts of such measures were largely borne by the New Zealand taxpayer as owners of affected SOEs, they were not confined to the public sector. Such interventions notwithstanding, industry proceeded with initiatives instigated at industry level on the understanding that its destiny remained fundamentally in its own hands.

<sup>21</sup> As argued in Chapter 3, vertically integrated gentailers are an efficient means of hedging wholesale electricity price risks. Enforcing minimum levels of contract tendering by generators has the potential to cause the de-integration of gentailers and create a possibly artificial rationale for independent retailers, who may well be at increased risk of failure.

With the recent reforms, however, it is not just the Electricity Commission that will find itself second-guessing the Minister of Energy. The most fundamental decisions affecting an interconnected electricity system – those relating to transmission pricing and investment – are now in the Commission’s hands. Since the Commission is accountable to the Minister, and not to industry, the prospects for decentralised-based investments and innovation are now changed. If the Commission levies industry to fund expansions there is the prospect that it does so too generously, encouraging over-investment at the expense of consumers but possibly to the benefit of Transpower (or even private investors). However, the risks to Transpower and any private grid investors, and to investors in generation reliant on transmission across the grid, now more tangibly extend to the risks of expropriation and potentially changeable political direction. Additionally, they face the direct and indirect costs of regulation and political influence in the sector.

While government has set out to encourage distributed generation by lines companies, which should at least partially skirt around constraints in the grid and risks to its future development, such measures in themselves cannot resolve ongoing issues of supply security. With key decision-making powers now being taken from industry and vested squarely in the hands of the Commission and the Minister, and important aspects of those parties’ likely conduct yet to be seen and subject to changing political imperatives, those with the best information (and who would otherwise be in the best position to bear the risks and costs of investments in the electricity sector) find themselves in a much less secure position.

Conversely, while the recent reforms might be predicted to favour taxpayer-funded over private investments in the sector (if only by default), they also present opportunities to private investors adept at gaming regulators, lobbying politicians and otherwise engaging in “rent-seeking” behaviour.<sup>22</sup> It has to be asked whether this represents a desirable shift in private-sector investment incentives in an industry said to require significant new transmission expenditures and around 150MW of new generation capacity each year to meet expected growth in demand.

The very real risk faced by government in taking a more direct and managerial-like control of the electricity industry’s evolution is that private capital might be harder to attract or retain in the industry should investors find the evolving environment unsatisfactory. That would leave taxpayers, as owners of SOEs, bearing the risks of the industry’s evolution. Alternatively, any industry failures arising on the Electricity Commission’s “watch”, such as power outages in future winter crises and the major transmission outage of January 2004 (see Chapter 6), are likely to be viewed as the responsibility of the Commission and, ultimately, government – not the responsibility of wider economic and natural forces.

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<sup>22</sup> Industry participants have already expressed fears that the Commission will be manipulated by politicians and lobbyists, undermining its independence (see “Fears for Independence of Electricity Watchdog”, *Dominion Post*, 27 August 2003). Ironically they too might enjoy the benefits of engaging in such manipulation, and in the face of competing lobbies may find they have to. Electricity industry gaming has a new outlet.



## TRANSMISSION INSECURITY – WHAT’S AT FAULT?

In late May 2004 the national grid operator Transpower announced that transmission capacity to the north of the South Island was no longer sufficient to meet peak winter demands, with the possibility of power cuts within mere days. Just six weeks earlier, in its annual report of 2002, it had forewarned of shortages – but not until winter 2005. At around the same time the Electricity Networks Association, representing 28 electricity lines businesses, was openly challenging aspects of Transpower’s proposed upgrades to the national grid. Both the new Electricity Commission and the Minister of Energy appeared to be caught flat-footed by Transpower’s announcement.

This one episode highlights two important facets of electricity industry arrangements in New Zealand. The first is that centralised state planning for new grid investment would appear to have failed to deliver grid security. The second is that there is now either confusion or potential conflict as to where responsibility lies for ensuring that grid capacity is sufficient to meet demand.

Criticism of New Zealand’s electricity reforms has typically focused on allegations of “market failure” and a lack of centralised coordination of generation and transmission operation and development. Such criticism is often associated with calls for a return to state-owned and centralised control of the electricity system.<sup>23</sup> Rarely, however, has such criticism been directed towards any real or perceived governance or administrative failure, either on the part of government or other centralised industry bodies (except perhaps the wholesale market). The potential transmission failures of winter 2004 present a stark counterpoint to such attitudes.

From the time Transpower was separated from state-owned generator ECNZ and set up as a stand-alone state-owned company in 1994, it remained responsible for grid security until the passage of the Electricity Amendment Act 2001. Throughout that time it was wholly owned and ultimately controlled by government, and was one of a few state-owned enterprises whose SOE Act characteristics were specifically changed from a relatively pure business focus. While Transpower advocated the creation of market-based financial transmission rights (see Chapter 2) as a means of improving signals and incentives for grid investment (potentially instigated by third parties), it was unable to do so and remained a centralised administrator determining when, where and how new grid investments would be undertaken. This was subject to the pricing allowed by the Commerce Commission that offered scant ability to fund investment in advance of demand. To the extent that the reforms have failed to deliver an appropriate level of grid security, the fact that the highly centralised and government-owned grid operator

<sup>23</sup> Indeed, Transpower itself welcomed the creation of the government’s Electricity Commission as a means of overcoming what it perceived as the failure of voluntary arrangements to resolve multilateral issues such as transmission pricing and common quality standards. It also sees the Commission as a means of improving its revenue security and investment incentives by enforcing payment for grid investments.

is contributing to grid insecurity cannot for one moment be decried as “market failure” – rather it is “government failure”, or perhaps “centralisation failure”.<sup>24</sup>

Indeed, while expansion of New Zealand’s grid is argued by many to be overdue (although the history of loss and constraint rentals illustrated in Figure 3.18 does not support this view), various factors have militated against any necessary investment. First, moves to pass responsibility for grid-security policy to grid users, combined with the timing, scale and location of new generation projects being in the hands of parties not related to Transpower, have left the company – as grid central planner lacking alternative market-based mechanisms – with important investment uncertainties beyond its control.

Second, as shown in Figure 3.39, Transpower has not since its separation from ECNZ, on average, earned a rate of return on its system assets commensurate with that on investments of comparable risk (as measured by its target required rate of return). If Transpower has been unable to earn a commercial return on its existing assets, it is no surprise that it has been unable to convince its government shareholders or public providers of the necessary capital that new investments can be commercially justified.

Finally, industry uncertainty generated since the government’s 2000 Electricity Industry Inquiry has been an important contributor to the current transmission difficulties. The Inquiry mooted a new “partnership” between Transpower and government, led to the major reforms in the 2001 Act, and presaged governance and grid-pricing and investment uncertainty in the sector that remains to be resolved. It might be argued, therefore, that Transpower has found itself a hapless pawn in a wider industry game being dictated by government.

As to the second facet of concern, the 2000 Electricity Industry Inquiry recommended that Transpower remain responsible for undertaking new grid investments, but the subsequent 2001 Electricity Amendment Act passed responsibility for overall industry responsibility to the new Electricity Commission (section 172L, and principal objective section 172N). The new Commission, furthermore, was empowered to regulate grid investments, determine the allocation of associated costs, set grid-security standards, and fix grid-pricing policy (section 172D; all outstanding as at May 2004). It is perhaps no surprise, therefore, that the chief executive of Transpower denied responsibility for the looming transmission shortages and pointed the finger of responsibility at the Commission.<sup>25</sup> It is also no surprise that Transpower’s 2004/05 SCI highlights regulatory uncertainty as potentially hampering the achievement of its corporate objectives.

<sup>24</sup> At least one commentator attributes the failure to the separation of generation and transmission in 1994 (see “Power Users in Line for New Jolt”, *Dominion Post*, 1 June 2004). If this is true, then once again this represents “government failure” (or, if preferred, “reform failure”), but it clearly cannot be described as “market failure”.

<sup>25</sup> “So Who Does Keep the Lights On?”, *Dominion Post*, 28 May 2004.

## BOX 8.4

## Transpower's Evolving Statements of Corporate Intent ...

Transpower's board is required to produce a statement of corporate intent (SCI) for each financial year (and two subsequent years) after consultation with its shareholding ministers. Excerpts from Transpower's SCIs follow.

**1994/95-1996/97**

As per the SOE Act 1986, Transpower's principal objective was to operate as a successful business and (*inter alia*) be as profitable and efficient as a comparable non-Crown-owned businesses. To assist with the fulfilment of that objective, Transpower was required to:

- 1) provide an efficient reliable and secure national grid at least practicable cost;
- 2) provide transmission services and grid access on transparent terms which (*inter alia*) reflect cost, facilitate efficient supply delivery and use of electricity and promote efficient use of its resources;
- 3) supply information to facilitate efficient investment decisions by both it and grid users; and
- 4) earn a commercially appropriate return having regard to its business risk.

**1997/98-2000/01**

In September 1997 government determined that industry should play a greater role in setting core grid quality requirements, and amended Transpower's SCI accordingly. The primacy of operating as a profitable and efficient business was now replaced with an overriding requirement for operational efficiency, and government's ability to influence Transpower's pricing policy was made more explicit. Within this revised framework, the amended SCI now required Transpower to continuously improve the efficiency of its transmission services by:

- 1) making its services contestable where possible and producing them at least cost;
- 2) producing services at a quality and quantity as agreed with customers, with customers making trade-offs between service level and price, and establishing processes and a contractual framework to facilitate the achievement of this and to govern system co-ordination and real-time electricity security; and
- 3) pricing services in accordance with government statements of electricity policy relating to electricity as issued from time to time under section 26 of the Commerce Act 1986 to the Commerce Commission.

*box continues ...*

**2001/02**

A "fair return to shareholders based on commercially appropriate principles" remained subsidiary to other objectives, which were expanded to include:

- 1) promoting the government's energy policy of electricity being delivered in an efficient, fair, reliable and environmentally sustainable manner to all classes of consumers;
- 2) promoting system enhancement and replacement;
- 3) reintroduction of a need for it to price transmission services to facilitate nationally efficient supply, delivery and use of electricity; and
- 4) continuously improve the efficiency of its services, but now by producing them at least overall cost while ensuring short term security of supply.

**2002/03**

The SCI was similar to 2001/02's, but introduced an element of ambiguity with an amended requirement for Transpower to earn a fair return "in delivering" its other objectives. It was no longer clear that these other objectives took precedence over that of earning a fair return.

**2003/04-2004/05**

These SCIs appear to make the achievement of 16 other goals as diverse as sustainability and staff retention at least as important as the principal objective of business success. They also reflect the creation of the Electricity Commission as industry's governing body and regulator.

Transpower's history is littered with a profusion of objectives and changing priorities. Its latest objectives expand beyond core operational requirements to incorporate a plethora of goals related to wider government policy. The importance of the grid to industry make-up and performance remains – but the achievement of its more fundamental objectives (e.g. promoting efficient transmission investment) is at risk of being frustrated by the pursuit of these other goals. Where conflicts in objectives arise both performance measurement and performance itself should be expected to suffer.

Source: Transpower annual reports (various years) and [www.transpower.co.nz](http://www.transpower.co.nz).

Curiously, despite the Commission being generally responsible for achieving its principal objective of (*inter alia*) ensuring the reliability of electricity supply, the chairman of the Commission was reported as denying responsibility for overall supply security, instead referring to the Commission's specific responsibility to ensure that there is sufficient reserve generation for dry winters.<sup>26</sup> Despite this denial the Minister of Energy described the Commission as being the solution to the transmission problem, stating that it had the power to "ensure upgrades were made when there was a need", and indicating that Transpower could seek a capital injection from its shareholding ministers if this was needed.<sup>27</sup> Clearly to the extent this was so, it was not yet working; nor is it likely to be for some time.

This chain of events betrays not only a confusion of responsibilities, but also an inflation of the Commission's ability to implement solutions. The substance of the 2001 Electricity Amendment Act is that Transpower has been left as mere owner of the grid, operating it under contestable contract (first to the New Zealand Electricity Market, now to the Electricity Commission), but with responsibility for grid investment and pricing now taken from it and passed to the Commission (a party with inferior knowledge about the grid, and a wider set of objectives to satisfy). While Transpower is to implement any required grid upgrades and bear the associated financial risks (which must sit uncomfortably with any ongoing requirement for Transpower to operate profitably), it is the Commission that ultimately decides what grid expansions can or cannot be undertaken. Important governance tensions would appear to remain between the 2001 Electricity Amendment Act and the 1986 SOE Act.

Furthermore, aside from its informational disadvantages, the Commission has no balance sheet of its own, and hence is constrained in its ability to see that required grid investments are identified and occur. At best it can seek to instruct Transpower to undertake any grid investment it considers necessary, but it is reliant on Transpower for the required implementation.<sup>28</sup> In short, the 2001 arrangements create a separation of roles and responsibilities that arguably exacerbate any difficulties in ensuring desirable grid investments are undertaken in a timely and efficient manner – for example, to ensure system security. Transpower bears the financial risks of poor investments determined by the Commission, and the Commission (and ultimately government) bears the risk of failing to ensure system security through a party it imperfectly controls. Decentralised grid-investment solutions appear to have been eschewed in favour of

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<sup>26</sup> *Ibid.*

<sup>27</sup> "Government Aware of Power Problem", *Dominion Post*, 2 June 2004.

<sup>28</sup> For Transpower to undertake grid upgrades it must first obtain the approval of its government shareholders, the Electricity Commission, the Commerce Commission, and owners of land on which new pylons are to be built, as well as consents from various regional councils under the Resource Management Act 1991. None of these decision layers can expedite the investment; they merely create delays and uncertainties, and impose constraints.

“divided centralisation”. In any case, grid capacity has proven itself inadequate in the context of a neutered Transpower – and this has occurred on the “watch” of the government’s new industry regulator, the Electricity Commission.

The fact that the Commission took the lead in creating arrangements to avoid transmission-related power cuts in winter 2004 says nothing about the benefits of centralised over decentralised decision-making.<sup>29</sup> Industry was able during both the 1992 and 2003 winter crises to create similar arrangements, despite government having assumed a role in the 2001 winter crisis (see Chapter 6). The fact that argument remains as to who (i.e. whether Transpower) should bear the cost of achieving required demand reductions highlights the degree of flux inherent in recent reforms. The prospect of the Commission seeking to determine whether Transpower was at fault for not implementing grid upgrades sooner illustrates how responsibilities will ultimately be determined when diffuse responsibilities and accountabilities arise under increasingly bureaucratic control of the industry.<sup>30</sup>

## CONCLUSION

With improvements in communications and control technologies, it is now harder than ever to argue that centralised control of the electricity system is a technical necessity. The existence of diverse, interconnected electric utilities and grids in Europe and the US provide ample demonstration of the feasibility of running such systems with an acceptable level of reliability (notable but exceedingly rare exceptions aside). The advantage of allowing such decentralisation is the encouragement of competition in electricity supply – in generation and transmission – in both the economic and intellectual senses. Investment risks have correspondingly been shouldered by private-industry participants instead of captive taxpayers and consumers.

New Zealand’s electricity reforms initially sought to replicate many of the decentralisation measures adopted or existing elsewhere. Control of the all-important grid has remained highly centralised throughout, however, as has state ownership of much of generation (which now also extends to energy retailing). While light-handed regulation was initially employed, and on the evidence in Chapter 3 not been glaringly unsuccessful, New Zealand has since 2001 rapidly embarked on a process of re-centralising electricity industry governance under state control. Indeed, where the 2001 reforms proved inadequate, they were quickly augmented – some would say inevitably so – by even greater powers to the new industry governing body, the Electricity Commission. Not only does that body lack the independence

<sup>29</sup> “Emergency Plan to Cut Blackout Risk”, *Dominion Post*, 5 June 2004.

<sup>30</sup> “Grid Upgrade Vital, says Transpower”, *Dominion Post*, 1 June 2004.

from its minister that comparable regulatory bodies would normally enjoy; it also faces the impossible task of delivering industry outcomes that cannot be expected under either centralised or decentralised industry control. The fact that it suffers informational disadvantages relative to those it is regulating merely worsens its position. The sustainability of this awkward half-way house – combining heavily centralised industry control, to the extent that the regulator involves itself in decisions of a managerial nature, with private electricity interests – must be questioned given the inevitable shocks it will face and the wide-ranging yet inadequate instruments it has for responding to such shocks.

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**APPENDIX 8.1 – INDUSTRY EVOLUTION, MARKETS, POLITICS,  
AND DE/CENTRALISATION**

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**INTRODUCTION**

This appendix provides background to discussions in Chapter 8. It touches on factors influencing industry evolution and the interface between politics and markets, and on the experience under centralised control in Eastern European countries. It concludes by noting the common mixture of centralisation and decentralisation commonly observed in typical “western” economic systems.

**INFLUENCES AFFECTING INDUSTRY EVOLUTION**

Industry evolution commonly involves the creation of structures or arrangements reflecting interests common to that industry’s members. The New Zealand banking sector, for example, was an early adopter of a centralised computer-based inter-bank clearinghouse developed as a cooperative venture. The agricultural sector has developed industry-research organisations whose research outcomes are intended to benefit the sector at large and not individual members of that sector. In the electricity sector a number of key developments have arisen in response to industry initiatives, as discussed further below, not least because the interconnected nature of the electricity system requires industry agreement as to matters as fundamental as the physical characteristics of the electricity flowing through its wires.

Government involvement in the evolution of industry must also be acknowledged. While New Zealand’s electricity system had its genesis in various private and local-government schemes, the national electricity system came about through, firstly, direct state involvement in developing large-scale hydro and other generation; and, secondly, through a transmission grid linking major generation projects with distant population centres. Without such central government involvement it can rightly be asked whether the grid would have been developed at all, or in a timely fashion. At the same time it might be asked whether the private sector would have had stronger incentives to develop the national grid if central government had not taken over the business of generation and constrained, through legislation, the ability of private parties to access the nation’s hydrological resources.

As with questions regarding the boundaries of the firm, the answers to questions such as these require a balancing of relative costs. It may be true that suppliers in an industry are sufficiently concentrated or coordinated that they enjoy market power at the expense of their customers, but regulation is not costless in its impact or perfect in effect. Hence



the costs to consumers of regulation must be weighed against the costs of inaction. It may also be true that industry is slow to produce desired innovations, but history would suggest that state provision of goods and services is typically less customer-responsive and even less likely to innovate. Where industry gives rise to undesirable externalities such as pollution, or over-exploitation, regulatory intervention is one solution, but so too is the creation of tradable private property rights (such as emissions or water rights) – and one must bear in mind that state-dominated economies are often worse polluters than market economies.<sup>31</sup> And while private-sector capital may be hard or expensive to raise for necessary infrastructure investments, taxpayer funds for such projects cannot be assumed to be somehow cheaper or their use costless. An important challenge is to ensure that any necessary state involvement in a sector simultaneously preserves the benefits of private-sector and market-based endeavour, and that any unnecessary involvement does not stifle private initiative. A fundamental question is whether an activity has intrinsic characteristics requiring centralised control, or whether private parties can be left to organise that activity themselves.

## INDUSTRIES, MARKETS AND POLITICS

Economic endeavours do not arise in a vacuum: at any point in time they depend upon and mould institutions that they require. They must be regarded as pieces in a socio-political jigsaw, and as such will not evolve in purely economic terms. Broader societal agendas such as industrial relations and environmental concerns inevitably interface with the operations of firms and industries. Certain industries are sometimes regarded as being of such national importance that they face either state ownership and control or other heavy direct regulation. Others find themselves subject to political interest whether or not they possess critical attributes requiring state intervention. Such industries find themselves unnecessarily subjected to political objectives that often overlap with economic objectives, but which sometimes also involve considerable trade-offs. All of these beg the question as to whether this is necessarily or desirably so, but in any event their effects on industry structure, function and evolution will be real.

At the heart of the politico-economic interface is the question of how private incentives are affected by political interventions. Where such interventions are transparent and certain, private parties are able to adapt their strategies to accommodate (or subvert) their intent. Where they are inconsistent or obscure, private parties face net costs in attempting to work within (or circumvent) the political constraints. In either case it would require a coincidence of private and governmental incentives and objectives for

<sup>31</sup> For example, Bleaney (1988) and Kornai (1992) record that energy consumption per capita, steel intensity and air pollution (measured as sulphur oxides per capita) were noticeably higher in socialist countries than in capitalist countries. Growth targets, a lack of resources for conservation, and the danger of losing future allocations of resources (where resource savings were made) contributed to some of the environmental deficits arising under socialism.

government interventions to be relatively costless. Otherwise it must be expected that private parties will bear costs from governmental intervention which in turn will affect the nature, extent and course of their endeavours.

That final point is worth further mention – the course of private endeavours in the presence of political interventions. When private parties understand the rules under which they operate and are confident that any unforeseen future rule changes will not be materially adverse, they enjoy an environment conducive to long-term planning and investment. For sectors requiring major investments in long-lived and irreversible investments for which payoffs accrue over many years, as is the case for the electricity sector, such security is an important determinant of whether private parties will undertake such investments. Where political interventions involve or create uncertainty, however, or directly diminish the returns expected from substantial long-term investments (e.g. through regulation, levies or overt or implied price control), this must be expected to act as a disincentive for private parties to place their capital at risk, with implications for long-run industry performance.

Additional subtleties arise in this regard. The first relates to the impact of threatened, as opposed to actual, government intervention. Where government adopts a stance of threatening industry with overt interventions should it fail to deliver on either its stated or unsaid agenda, industry must then engage in a “game” of either “doing unto itself that which the government has threatened to do” (calling the government’s bluff) or second-guessing what it must do in order to avoid imposed interventions.

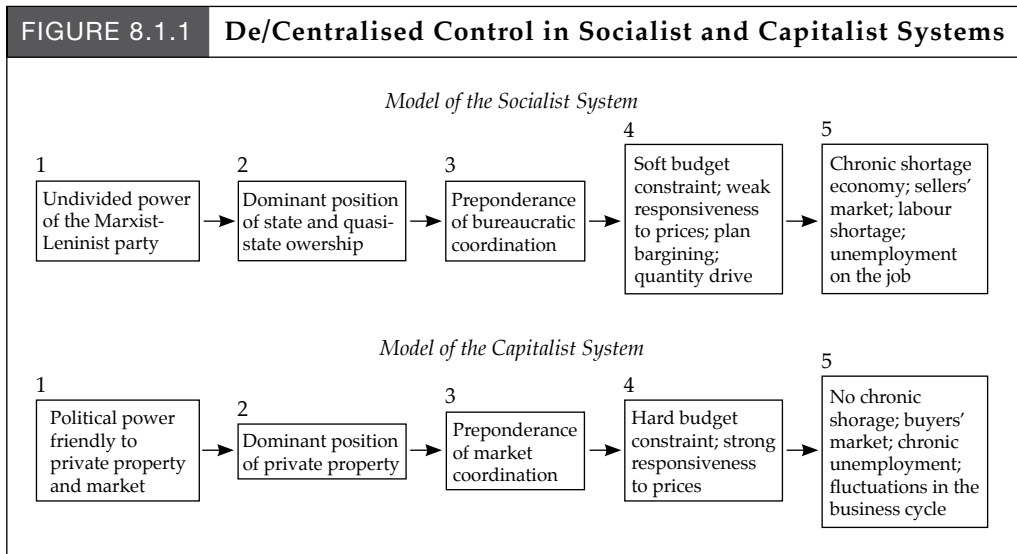
The second subtlety relates to the change in business focus that arises when government assumes explicit or implied responsibility for an area of activity in which private parties are, or wish to be, engaged. Where government interventions threaten the value of past private investments or materially affect likely returns from future investments, private parties no longer engage in an industry simply on its own terms. Instead they must keep a wary eye on government interventions, requiring potentially significant investments in monitoring and managing those risks, or an eye out for favourable interventions – so-called “rent-seeking” behaviour (see Chapter 9). When politicians specifically and materially intervene in private endeavour, a market for political influence can be the product.<sup>32</sup>

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<sup>32</sup> Recent experience in the New Zealand telecommunications sector is instructive, with rivals to the incumbent Telecom Corporation of New Zealand publicly appealing to the Minister of Telecommunications to disregard recommendations made by the independent Telecommunications Commissioner regarding access to Telecom’s local line network. When decision-making authority is centralised in the hands of government ministers who have discretion as to how and what they decide, lobbying is an essential outcome. See “Telecom Rivals Urge Government to Open Local Line Access”, *New Zealand Herald*, 16 March 2004.

## DECENTRALISED AND CENTRALISED CONTROL

Similar regard can be had to decision-making more generally. In particular, are there defining characteristics of a sphere of activity that dictate either centralised or decentralised control of that activity, or can it be left to its intrinsic forces to properly and usefully guide its conduct? The archetypal polar alternatives are often regarded as mercantilist Victorian England, and the USSR under Stalin. While each is an extreme example of decentralised and centralised control mechanisms respectively, they illustrate the hallmarks of either approach, as summarised in Figure 8.1.1.



Source: Kornai (2000).

Decentralised control relies on private parties to freely determine what, how and when to engage in a particular endeavour. Economic theorists as far back as Adam Smith predict that self-interest and social good need not be mutually exclusive, and it is the consumer benefit arising from increased competition that lies at the heart of electricity and other sector reforms around the world. Where the laissez-faire version of decentralised control resulted in deficiencies regarded as socially undesirable, such as child labour and environmental degradation, countries embracing the decentralised control model have typically adopted regulatory or property-rights-based solutions. To varying degrees these have preserved at least some of the benefits of decentralised control, particularly where they operate at a general rather than activity-specific level (e.g. minimum wage laws and tradable emissions permits, rather than occupation- or industry-specific regulation). Where they more directly and specifically influence the way in which the activity is pursued, greater centralisation of control results.

Centralised control instead places the authority, indeed the burden, of regulating an area of activity in the hands of one or more persons not themselves otherwise directly involved in that activity. It therefore involves an imposition on private endeavour, with the potential of quelling any private initiative involved. Conversely, it can arise where obstacles to private endeavour (such as a lack of defined property rights or inadequate expected returns) mean that private parties are unwilling or unable to undertake the activity of their own accord. In that case centralised control is not necessarily the only alternative, as solutions otherwise facilitating private endeavour (such as the creation of suitable property rights or subsidisation of desired activities) might also be possible. Just as centralised control can make things happen which otherwise might not (e.g. universal education), there are also activities so complex that centralised control becomes so complicated that it is either infeasible, or excessively costly. The danger is that centralised control is forced even in such circumstances, implying sub-optimal outcomes in each case.

The experience of Eastern European countries under communism (the most extreme central administration), and in making the transition from communism to more market-based and decentralised economies, provides useful evidence on the relative merits of the two approaches. Djankov and Murrell (2002) analyse evidence on enterprise restructuring in 27 countries from more than 100 empirical studies, finding (for example) that state ownership is less effective than all other ownership types (except worker ownership, which is worse), that enterprises in highly competitive sectors are significantly more productive than monopolies, and that privatisation to non-state/non-employee owners is associated with the largest restructuring gains. Similarly, Megginson and Netter (2001) survey the empirical literature on privatisations more generally, reflecting a shift away from centralised state control in favour of market-based mechanisms. They find gains such as 68% of firms enjoying increased profits (up 46% on average), 80% of firms paying higher dividends (up 113% on average), 82% of firms enjoying increased productivity (up 19% on average), and total employment slightly increased. Shleifer and Vishny (1997) utilise earlier evidence while surveying systems of corporate governance, arguing that even where centralised state control is typically regarded as necessary – for example, because of monopoly power, externalities, or distributional or environmental concerns – private, decentralised approaches are commonly superior. The evidence of such surveys suggests there is good reason to pursue private, decentralised approaches rather than centralised, state-based solutions; and even where the latter are indicated, great care is required.

Much private endeavour proceeds under even industry-specific regulation, such as regulated private electricity utilities in the US, although this arrangement arguably arose for anti-competitive reasons (see Chapter 4). Markets formed as a consequence of private initiative are often subject to regulatory oversight, such as the New Zealand stock exchange, whether as a means to control undesirable behaviour, or an attempt by incumbents to deter competition by new entrants. Hybrids can involve interventions

at the level of rules and institutions (e.g. basic laws covering the creation and operation of companies), but can extend as far as direct interventions such as imposed price caps (e.g. the general price freeze imposed in New Zealand in the early 1980s) or price floors (e.g. agricultural subsidies). They can also arise as a means of facilitating private endeavour, such as through legislation standardising weights and measures. Even communist China now, and Russia under Lenin, show the benefits of limited private endeavour under otherwise highly centralised state control.



*In this chapter the interrelationships between gaming, market power and regulation in the New Zealand context are explored, with a deconstruction of each intended to isolate when, if and how each has its place in a healthily evolving electricity sector. We begin by contrasting gaming with market power, since they are distinct phenomena with differing implications. Circumstances in which either is malign, benign or simply tolerable are discussed. Given the particular difficulties that can arise with market power, the discussion traverses not only its incidence in each major sub-sector of the electricity industry but also the issues associated with measuring market power. The discussion then turns to regulation, considering its purpose, rationale and approach (with further details discussed in Appendix 9.1). Ownership options representing alternatives to regulation are raised, including one – for Transpower – which was raised but shelved early in New Zealand’s reforms. Finally, some reflections on New Zealand’s evolving regulation of the electricity sector are offered. In short, current regulatory settings are overly blunt and excessive given certain existing arrangements and alternatives.*

## INTRODUCTION

The discussion in Chapter 8 – regarding the impact of governance changes on the incentives various parties have to make the large, long-term and irreversible investments required for a growing electricity sector – presages a wider discussion. By now it is probably apparent, if not self-evident, that the interdependencies in the electricity sector arising from network physics and economics only intensify the interrelationships characterising any sector of the economy. In the case of electricity these interrelationships extend not just between governance and investment, but between those matters and issues of market power (whether seen as a necessary evil or otherwise) and its nemesis, regulation. Often tarred with the same brush as market power is the issue of “gaming”, frequently leading to similar calls for regulatory intervention, but it would be both inaccurate and, as we shall see, potentially misguided.

## GAMING

Gaming and market power are often perceived as co-evils in the electricity sector. Whereas market power in this context typically takes on its usual meaning of market participants having some capacity to increase prices beyond cost-based levels and/or to restrict output to increase profits and prices, gaming appears to sometimes degenerate to mere tautology. In New Zealand it most commonly refers to the ability of generators to push the boundaries of market rules under which the wholesale electricity market operates, to increase electricity prices above what is argued to be reasonable. Allegations of gaming often arise in the context of transmission constraints causing the wholesale market to “separate” or “regionalise”,

resulting in fewer generators in the resulting sub-parts of the electricity system meeting existing demands. They are at their loudest during extreme events such as winter supply shortages or transmission outages (as discussed in Chapter 6).

In its plainest sense gaming is simply a fact of life, and one which many of us accept and at times even value. This is the sense in which gaming is simply playing the rules to one's own advantage, in a situation where others might be affected as a consequence and whose responses might also affect the gamer's own outcomes. New Zealanders do this at every general election – particularly since the introduction in 1996 of mixed-member proportional representation, which gives each voter the ability to vote for both an electorate candidate and a political party whose winning candidates are drawn from a predetermined party list. Every time a voter exercises their votes, they game, and if they consciously exercise their two votes in favour of either the same or different political parties, they do so strategically. So far so good.

### *Pernicious Overtones*

Gaming takes on more pernicious overtones when it nears the point of rule-breaking, when it is regarded as being exercised by parties with excessive absolute or relative “power”, or where the “rules of the game” are seen to unduly or deficiently afford power to some groups over others. Such power might be attributed to structural matters such as the number (e.g. lack) of competing generators, or bottlenecks in the transmission grid that can lead to localised increases in the ability of generators (or demand) to manipulate prices to their advantage. Alternatively, market power might involve a vertically integrated generator and retailer driving up wholesale spot prices while holding or lowering retail prices to financially stress non-vertically-integrated retailers exposed to rising wholesale prices. The Market Surveillance Committee (MSC) of the New Zealand Electricity Market (NZEM), however, in considering allegations of the latter during the 2001 winter supply crisis, regarded such actions as expressions of market power.<sup>1</sup> In doing so it distinguished them from “manipulative activity”, which it defined as “the use of a device or technique which artificially sets (or attempts to set) a price in a market which does not reflect the basic forces of supply and demand at work in that market”.<sup>2</sup> Accordingly, the dark side of gaming requires alternative substantiation.

An aspect of gaming that bears closer scrutiny relates to the potential for market rules to be used in ways not intended, or outright circumvented by fair means or foul.<sup>3</sup> As should be evident from the discussion in Chapter 2, electricity markets are an artifice, sometimes created with a “big bang” (and sometimes succeeded by a number of

<sup>1</sup> Indeed, the Committee noted that the alleged use of market power was in fact directed at competing retailers, while consumers remained relatively insulated from its effects, or even enjoyed electricity prices allegedly at less than cost. Such short-term consumer gains must be balanced against any longer-term adverse consequences, which the Committee acknowledged and we discuss subsequently.

<sup>2</sup> New Zealand Electricity Market (2001).

<sup>3</sup> Gaming-type actions are also constrained by the Commerce Act.



smaller bangs, or even fizzes), reflecting the fact that they arise from a background of centralised, planned control – with a central planner seeking to inject greater market and competitive forces – rather than evolving as a consequence of such forces. It is therefore too much to expect that the reformers get it completely right, on successive tries let alone first time, particularly when institutional and other obstacles to change are considered. The rules applied to reformed electricity markets may well need refinement. As stated by Crew and Kleindorfer (2002) in their “helicopter” tour of the past 20 years of regulatory economics, one of the biggest lessons learned over this period is the importance of practice. Of course a less generous interpretation would be that electricity-sector reforms at their worst represent a sequence of fumbles.

### *Lessons from England and Wales*

An important lesson can be taken from the reform experience in the England and Wales electricity system. As suggested in Chapter 2, a number of the features of the original England and Wales pool predisposed it to manipulation by generators, quite aside from any market power they possessed. Critically, the pool at first allowed no demand-side bids and hence no demand-side response to wholesale prices as they neared trading period determination, relying instead on system-operator demand forecasts (a fraught activity at the best of times) to determine which generators to dispatch. Generators were afforded considerable ability to revise their capacity commitments (although not their dispatch prices) up until the point of dispatch, which under market rules significantly affected the various pricing components that made up final prices. With the system operator responsible for maintaining system security, its degrees of freedom were limited by last-minute generator withdrawals of capacity commitments, instead allowing generators a degree of freedom to play off dispatch prices against prices for reserve capacity. A good way to allow market rules to be played by generators is to write them in a way that backs the system operator and consumers against the wall, while leaving generators with flexibility and discretion. The highly decentralised approach replacing the pool in England and Wales, NETA, represents a rewrite of market rules that simultaneously gives greater flexibility to consumers through demand-side contracting and power-exchange trading, and shifts the onus for maintaining system balance from the system operator more towards generators and purchasers. The scope for market participants under NETA to game the rules should now be reduced, or at least be much more balanced, than under the pool.<sup>4</sup>

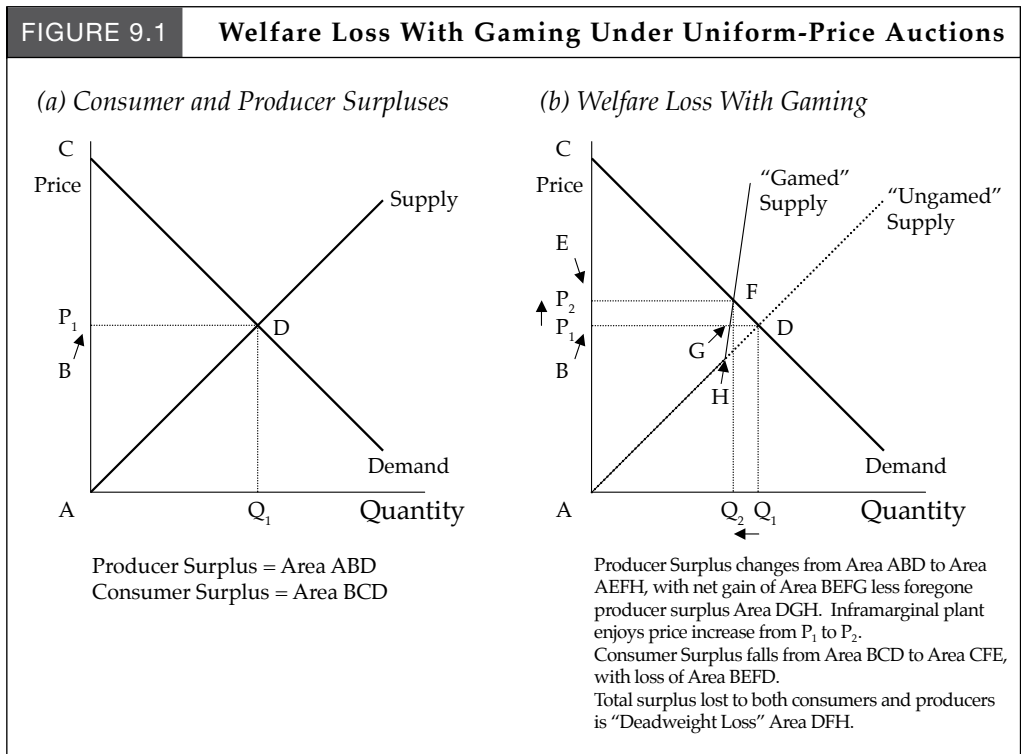
### *Problems with Uniform Price Auctions*

A concern with the England and Wales pool leading to other changes under NETA, and one which was raised following the Californian electricity reform debacle, relates to the nature of the auction rules implemented for setting electricity prices. In each case generators were dispatched via a centralised auction with “uniform pricing”. Under this approach all dispatched generators are paid the “market clearing” price, i.e. that which

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<sup>4</sup> Indeed, Zhou *et al.* (2003) report evidence from the first year of NETA operation that finds no abuse of market power or significant gaming of procedural rules, both of which plagued the pool of England and Wales.

equates demand with offered supply. In this regard it mimics the typical operation of any market, since the price at which goods or services are traded in “equilibrium” is set by the “marginal” supplier and consumer, meaning some consumers pay less than what they would be prepared to in order to consume the relevant good or service, and some suppliers are paid more than they need to be in order to attract their supply. Respectively consumers and producers enjoy “consumer surplus” and “producer surplus”, represented by the shaded areas in Figure 9.1(a).



Source: Richard Meade.

A criticism of uniform-price auctions is that they afford generators with multiple plants, especially those with differing technologies and hence multiple plant cost structures, the incentive to increase offer prices on the plant they own which they expect to be the “marginal” or “price-setting” plant in order to increase the profits they enjoy from their “infra-marginal” plant that will be dispatched earlier in the “merit order”.<sup>5</sup> By

<sup>5</sup> As noted in Klemperer (2002), uniform-price auctions are also vulnerable to demand-side collusion (tacit or explicit) to drive prices downwards, and the electricity regulator in England and Wales believed the pool fell prey to such collusion once demand-side bidding had been introduced. Evans and Counsell (2003) question whether purchaser gaming of the real-time and day-ahead markets in California was due to the use of uniform-price auctions in both.

skewing upwards the market clearing price, such generators seek to increase producer surplus, which consequently reduces consumer surplus and gives rise to a loss in combined surplus – a “deadweight” or welfare loss – as indicated in Figure 9.1(b).

### *Calls for Pay-as-Bid Auctions*

It is not surprising that some have seen this risk in uniform-price auctions as sufficient reason to call for alternatives, notably “discriminatory” or “pay-as-bid” auctions. Under this alternative, generators are paid the prices at which they offer each unit of their generation for dispatch, with only the marginal plant receiving the market price. In this case all producer surplus is extracted, apparently to the benefit of consumers – thereby mitigating the incentive to raise prices so returns on infra-marginal plant can be increased.<sup>6</sup> The subtle trap with concluding that this represents a net gain over uniform-price auctions is that it ignores the profound effect a discriminatory auction has on participants’ incentives and bidding strategies. To avoid the “winner’s curse” associated with bidding at less than the market-clearing price, under discriminatory auctions generators have an incentive to second-guess what the market clearing price will be and raise the price on all their plant to ensure they receive no less than that price (a strategy favouring larger operators with diverse plant and the resources to invest in estimating the likely market-clearing price).

It is therefore a mistake to assume that generators will offer plant in a discriminatory auction based on marginal supply costs, as they are more inclined to do under uniform pricing. With a change in rules, there is a change in bidding strategy. The net result is that discriminatory auctions can in fact increase market prices over uniform-price auctions, and shift generators’ attention from cost-based bids to second-guessing competitors’ bids (driven by strategy and informational costs more than production costs). The jury remains out on whether NETA’s use of discriminatory auctions in its balancing market has resulted in higher balancing prices than would be achieved under uniform pricing. The consequence of any mis-step in this direction, however, should be diminished relative to the pool since the balancing market represents only 2% of total electricity traded, whereas the pool priced all traded electricity (although much of that was hedged). Electricity auctions are repeated at different network nodes repeatedly (in New Zealand 48 times per day) so the necessity for effective auction rules is plain.

As noted by Klemperer (2002), any repeated auction is vulnerable to the risk that auction participants discover the bidding strategies of their rivals and peers and implicitly or explicitly use this information to collude (on either side of the market) in order to

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<sup>6</sup> This is the diametric opposite of how a perfectly-price discriminating monopolist would seek to extract all available consumer surplus from consumers by charging each consumer the price he or she is willing to pay.

manipulate prices.<sup>7</sup> He suggests this is best solved by improved auction design rather than legal intervention. Coordinated actions are facilitated by transparent information flows, a stable environment, reasonably similar costs and, in the case of electricity, known hedge arrangements. The volatility and uncertainty of water inflows, and uncertainty about gas supplies, affect different generators differently at different times, rendering cooperation more unlikely in New Zealand. Uncertainty in this country is intensified by the large electricity demand of one participant – the aluminium producer, NZAS – and by the presence of a methanol producer that has historically consumed approximately 40% of the production of natural gas in New Zealand. While it may be seen as a longer term risk, the withdrawal of either of these firms would materially affect the financial performance of generators and other participants in the electricity sector.

### *Changing Issues*

Gaming is thus a potentially potent issue, and one which requires ongoing attention. Compliance with market rules requires monitoring, and transparent and even-handed enforcement – an overlap with questions of governance. More fundamentally, market rules themselves require ongoing evaluation to ensure they are performing as intended, and that they are evolving adequately in line with external changes such as in industry composition (e.g. number of players) and structure (e.g. degree of vertical integration). In this regard the possible need for changes to the NZEM rules was flagged by the MSC in 2001, with the Committee observing that both market governance and rules were drafted in the context of generators and retailers competing on opposite sides of the market but that this situation had dramatically changed with the vertical integration of generation and retailing in 1999. As at June 2001 net generators constituted 76% of votes on the NZEM Rules Committee, with net purchasers the other 24%. As such, the potential for net-generator domination of future rule changes could not be precluded. The import of any such domination should not be overstated, however, since the vertical integration of generation and retailing, often involving finely balanced portfolios of generation and demand, means that either group of participants has relatively balanced interests. Hence any move by the new Electricity Commission (which assumed responsibility for NZEM governance on 1 March 2004) to include greater demand-side influence on market rule-making based on such considerations may be misplaced.<sup>8</sup>

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<sup>7</sup> Debate in New Zealand over how soon to release bid and offer information reflects the necessary balancing of market-power detection and other information gains against the competitive costs of facilitating strategic behaviour. Strategic behaviour may be enhanced because the revelation of individual bids or offers inform other generators of decisions taken and offer the possibility of inducing coordinated action in which cooperating players observe that others are not cheating on (implicitly) agreed strategies.

<sup>8</sup> Evidence by Mansur (2003) from PJM in the US, which also has vertically integrated firms, supports this view, with prices at competitive levels except for firms that are large net sellers (who withhold output relative to competitive levels).

*Gaming of a Higher Order*

An exception to this caveat might relate to those few, larger electricity users who choose not to hedge their exposure to wholesale spot prices (in which case any exposure to gaming is a risk they bear voluntarily, perhaps because it is not important enough for them to do otherwise) because they regard the prices of available hedges unattractive, and decide not to create their own self-generation (instead relying on demand management). Various alternatives to market transacting are a real prospect when such users are in a position to game the system, whether at the level of market rules, market-rule setting, governance, regulation or policy-setting, or law-making. It has to be recognised that market transacting has costs and benefits that market participants will weigh against those of the available alternatives. For larger electricity users these can often favour lobbying for regulatory change – irrespective of the effects on other users – rather than playing within the letter and spirit of existing rules.<sup>9</sup> Accordingly it is imperative in any discussion of gaming and its real or perceived evils that any solutions mooted do not simply shift the problems of gaming to different and potentially less-transparent and clearly rule-based arenas. The more decentralised the control of the electricity market, the less incentive there will be for such high-level gaming.

## MARKET POWER

*Horizontal and Vertical Variants*

Gaming's big ugly step-sister is market power. Changing market rules (or higher-order forms of regulation) is relatively easy; changing the market-wide characteristics that contribute to or alleviate any adverse consequences of market power can require consideration of more fundamental and potentially obstinate problems. Not least among these is the number of firms in the sector, itself a reflection of the costs of available production technologies and the size of the market. From such considerations is derived the definition of **horizontal market power**, referring to the ability of one or more firms to consistently or deterministically raise prices beyond competitive levels because they control a significant proportion of capacity and are not subject to the threat of timely entry by competitors. Also relevant is **vertical market power**, whereby a generator integrated vertically with transmission, distribution and/or retailing uses control over one or more industry levels to restrict competition at other stages (e.g. by restricting network access to other suppliers), with the effect that customers face higher than competitive prices.<sup>10</sup> Apart from the vertical integration of generation and retailing since 1999, for which considerations of vertical market power might remain

<sup>9</sup> The literature identifies “concentrated” interests as being more effectual than “diffuse” interests (e.g. households) in influencing policy that enhances their own objectives at the expense of others’ interests (see for example Magee, Brock and Young (1989)).

<sup>10</sup> See Vogelsang (2003) for a summary of relevant access-pricing rules in the context of vertically integrated telecommunications.

relevant, it is horizontal market power that receives most attention in the New Zealand electricity sector – in generation, transmission and distribution.

### *Market Power in Generation*

Clearly if the most efficient scale of generation, given available technologies, was such that only a single generation unit could most viably supply the entire market, then monopoly generation would be both natural and potentially “first-best” despite the welfare losses associated with monopoly. The challenge in such a case is to induce the monopolist to act in such a way as to reduce welfare losses while not creating additional and self-defeating new costs.<sup>11</sup> More typically in reformed electricity systems, in New Zealand and elsewhere, generation is dominated by a relatively small number of generators having a mixture of plant types and/or cost-structures. The Australian state of Victoria is an interesting exception, where single, large thermal generation units were each separately sold to different owners. With the incentives for such generators to game uniform-price auctions (as they have no infra-marginal plant from which to benefit from the usual games) having been reduced, it would be interesting to contrast the nature and extent of gaming in the Victorian Power Exchange prior to its integration into the Australian National Electricity Market (NEM). Gaming remains an issue for the NEM (see, e.g., Outhred (2000)), perhaps more a consequence of integrated generation units in New South Wales and elsewhere than because of gaming by Victorian generators.

Indeed, it should also be acknowledged – as the MSC does in NZEM (2001) – that market power can also be enjoyed on the demand side of the electricity market, with the balance of any market power in New Zealand ebbing and flowing with the relative scarcity or abundance of hydro reserves.<sup>12</sup> Also, the vertical integration of generation and retailing in New Zealand since 1999 – more so than that occurring (or sometimes even permitted) in other reformed systems – means that generators have reasonably well-committed output on relatively fixed prices, and therefore face little incentive to manipulate wholesale spot prices. Once again, the exposure to any market power may be borne in relatively greater measure by the few large electricity users that either do not hedge or periodically need to renew hedges for which the options at any time might be limited because generators are pre-committed to customers or because they need to manage their own risks (such as fuel supply in dry years).

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<sup>11</sup> Including bankrupting the generator, which is possible if otherwise-efficient “marginal cost pricing” is enforced when the most efficient scale of production lies beyond total market size, implying that such prices will not cover average production costs. Subsidies might be used to maintain the monopolist’s viability with marginal cost pricing, but that also incurs costs such as the distortionary effects of redistributive taxation.

<sup>12</sup> It would be difficult to sustain the argument that daily average main-centre wholesale electricity prices in the NZEM as low as \$0.01/MWh (arising in March 2004 when hydro reserves were 134% of average) reflected generator market power (or, indeed, production costs); but it might instead be thought to suggest demand-side advantage.

### *Market Arrangements to Mitigate Market Power*

Authors such as Stoft (2002) and Zhou *et al.* (2003) suggest that generator incentives to exploit any market power in wholesale spot markets can be mitigated by using long-term contracts to commit generators to supply at fixed prices. While this reduces the importance of the spot market as a mechanism for profitable manipulation, it simultaneously shifts the problem of ensuring electricity prices are set competitively into potentially inferior realms (e.g. bilateral contracts not subject to market rules), and can reduce the liquidity of the wholesale market with the effect that wholesale prices are more sensitive to any remaining manipulative behaviour. An alternative solution described by Counsell and Evans (2003) might be to implement a “day-ahead” forward electricity market which is sufficiently short-term that it will be both relatively “deep” and transparent, leaving the real-time market for top-ups when demand varies from loads contracted day-ahead (such as the scheme implemented in PJM). Yet another method of reducing incentives to exploit market power involves the use of wholesale electricity price caps, but this requires alternative means to balance supply and demand when price rises are genuinely required, and seriously distorts the price signals required to elicit generation investment in liberalised electricity systems (see Chapter 10 and Meade (2005a)).

### *Vertical Integration and Hedging*

The extent of generator vertical integration in New Zealand may seem to intensify an issue of market power also arising in less integrated industries, that of contract market illiquidity. Vertical integration does not adversely affect the ability to commit to long-term arrangements for supply: it is simply that most of such supply is committed through contracts written by generators’ own retail arms, rather than through middlemen retailers. Arguably, vertical integration enables better risk management, in part because generators can offer a wide range of contracts, some of which – household supply contracts – are variable and transferable. There should remain the same or better availability of non-spot-price supply for larger final-demand customers than if vertical integration had not occurred. Evidence on the extent and availability of these sorts of arrangements is hard to come by because each company jealously guards their fixed-price contract position, in part because knowledge of another’s hedge book reveals the vulnerability of that company to fuel-supply and price positions that might be exploited by competitors in certain situations. It is known that contracts range from fixed-price Contracts For Differences (CFDs), through household supply contracts, and contracts that share the risk of the spot price with customers, to those in which customers carry 100% of the risk. One of the four largest generators in New Zealand, Contact Energy, has publicly stated that approximately 85% of its average generation is hedged in some way. Generators have a demand for hedges in order to manage financial returns during times of lower prices, but they cannot be expected to be 100% hedged because in years where fuel supply is particularly limited for them – it may or may not be limited for others – they may have to buy on the spot market to meet their commitments at a hedge of 85% of average capacity let alone 100%.<sup>13</sup>

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<sup>13</sup> Their risk is more complex than this because it also depends upon the location of generation and hedges and the performance of the grid.

Further it should be noted that 100% hedging for all parties is impossible because some parties have to manage the intrinsic risk of demand and supply in the market. The more exposed parties are to the spot price, the stronger the incentive to plan other response measures to water and other fuel-supply shocks. It is to be expected that those better able to institute such responses will be those that choose to pay less for hedge contracts and are therefore relatively more exposed to risk.

### *Spot Market "Thinness"*

With an already small spot electricity market, the depth of competition at nodes for future delivery of electricity becomes even more "thin"<sup>14</sup> at a quickly increasing rate: hedge contracts of differing durations and locations are less homogeneous and hence less susceptible to competitive trading than spot electricity delivery at any node. Depending upon competition among the vertically integrated generators, it is possible that generators will enjoy some discretion over, even market power for, delivery of electricity at any given node at any given future date. Even in the centralised Australian national electricity market this remains an ongoing issue, with electricity futures markets of any depth slow to develop,<sup>15</sup> although under the highly decentralised NETA active financial forward markets have emerged.<sup>16</sup> What matters in an industry dominated by vertically integrated firms is the competition among them for customers: the shape and quantity of contracts (hedges) will reflect the generators' demand for hedge positions and the vigour of competition between them for customers.

### *Forced Hedging and De-Integration*

In New Zealand the issue of thin hedge and other long-term contract markets was in the 1990s resolved by forcing the then-state-owned monopoly or duopoly generators to offer a fixed proportion of capacity via long-term contracts. This is once again being considered via the Electricity and Gas Industries Bill 2003, enacted in October 2004, among other things empowering the new Electricity Commission to require generators to offer a minimum proportion of their output via supply and other hedge contracts. Such measures, however, now arise in a vastly different context. Generation is now vertically integrated, with most generators having relatively low excess capacity or demand. Forcing generators to offer long-term contracts to parties other than their own customers might require them to access the wholesale market to meet their existing

<sup>14</sup> In the financial market sense of having few buyers and sellers seeking to trade at each node for future delivery. This is to be contrasted with nodal instead of more aggregated (e.g. zonal) electricity pricing, which might suggest thin trading at each of the numerous nodes. However, the interconnected nature of electricity networks combined with Kirchhoff's laws means prices across nodes should be highly correlated (but for significant transmission constraints), a conclusion supported in the NZEM by Evans, Guthrie and Videbeck. (2003a).

<sup>15</sup> Council of Australian Governments (2002).

<sup>16</sup> Zhou *et al.* (2003) note that the OM London Exchange established the UK Power Exchange and an electricity futures market with the advent of NETA, followed soon after with a spot market. Two other independent exchanges also commenced operations, with the UK Automated Power Exchange offering a spot market and the International Petroleum Exchange a futures market.



customer requirements – increasing the exposure of those customers to any surges in wholesale prices such as during winter crises. Alternatively, it might force generators to at least partially de-integrate to ensure they are not over-committed.

The comparative advantage of generators vertically integrated with retailing in managing the risk of wholesale electricity price movements was introduced in Chapter 3. As discussed in Meade (2001), each provides a natural form of “self-hedge” to the other. Any policy or regulation that discourages such integration does so at the expense of this efficient means of risk management, begging the question as to what alternative measures might be required or even available to ensure customers are not exposed to dramatic increases in wholesale electricity prices (such as in winter crises). The difficulties that arise from inferior forms of retailing risk management could be observed in the 2001 winter power crisis (see Chapter 6) – even more so in the Californian power crisis (see Chapter 4) – with retailer bankruptcy either occurring or imminent. If gentailers were to de-integrate, then the need for mechanisms to contain flow-on financial distress and to ensure that retail customers continue to be supplied becomes all the greater.

A further complication is that any enforced offering of long-term contracts affects the operational policies and risk profiles of privately owned generators – risking the withholding or exit of capital from the industry should this interference prove excessive, or even the failure of these generators if they are unable to rebalance their commitments in an orderly manner (e.g. if they are caught by a winter crisis while still overcommitted). Greater long-term contracting is likely to benefit a few larger customers who reportedly experience difficulties in securing hedge contracts at prices they find attractive, and perhaps benefits new non-integrated retailers who might take advantage of customer sell-downs by over-committed integrated gentailers<sup>17</sup> (possibly to the detriment of the smaller customers currently integrated into generation).

#### *Importance of Transmission Constraints*

More critical for the vulnerability of an electricity system to the effects of any generator-related market power, however, is the potential bottleneck represented by transmission constraints. It is because of such constraints that the standard measures of market power are inadequate and likely to be misleading.<sup>18</sup> In short, where transmission capacity is scarce relative to likely demands, there is not only the potential for the electricity market to become fractionated or “regionalised” into smaller sub-markets with fewer

<sup>17</sup> Any new non-integrated retailers would be mindful of the lessons of 1999 when integration restrictions on generators were lifted with the final break-up of ECNZ, resulting in the rapid retail dominance of integrated gentailers. Their survival will be dependent on the continuation of any policy of forcing generators to offer a certain proportion of their capacity via long-term contracts, exposing them to no small risk of regulatory u-turns.

<sup>18</sup> The “textbook” measure of market power is the Herfindahl-Hirschmann Index (HHI), and this is discussed in detail in the section in this chapter on testing for market power. In any case, Arnold *et al.* (2003) note that many New Zealand industries are highly concentrated simply because of the size of the national economy.

generators available to vie for existing demands, but also the capacity for generators (and possibly even consumers) to use such constraints as points of leverage about which to gain advantage. In short, transmission constraints affect market power in generation and consumption; and participants can attempt to bring about transmission constraints in order to create it.<sup>19</sup> Compounding these problems is the fact that grid operation is directed towards grid security and not towards mitigating the costs of market power borne by grid users: in effect, some grid users can have interests conflicting with those of other grid users who might be prepared to trade short-term supply security (both their own and that of others) to relieve the costs they bear of market power arising because of grid constraints.

Various authors have investigated the effects of transmission constraints and expansions on horizontal market power. Surveying multiple papers, and based on his own analysis, Leautier (2001) cites a consensus that generators are indeed able to exercise market power when transmission is congested, and that “rents” from congestion pass from grid owners to generators in consequence.<sup>20</sup>

Indeed, Leautier argues that generators benefit from a reduction in grid capacity, and concurs with authors such as Borenstein, Bushnell and Stoft (1999) and Borenstein, Bushnell and Knittel (1999) who find that even small increases in grid capacity can result in significant reductions in generator market power and increases in consumer welfare. These results can arise even where little power actually flows over new grid capacity – with just the threat of competitive entry by other generators sufficient to constrain dominant generators within a transmission region. This conclusion warns against evaluating grid-investment proposals simply in terms of their anticipated throughput. To achieve the full benefits of generator competition, transmission capacity must be such that generators prefer to compete over a larger market than exercise market power in a constrained residual market. Other means to achieve the same or at least some of these results is to increase the price-responsiveness of electricity demand (i.e. flatter demand curves – the perennial and potentially two-edged goal – see Chapter 7) and/or increased generation. In the latter case the location of generation relative to demand is

<sup>19</sup> Cardell *et al.* (1997) describe how market power in electricity networks need not involve firms restricting output to increase prices, but can extend to firms increasing output to invoke grid constraints and thereby “constraining off” a disproportionately greater share of competing generation.

<sup>20</sup> The “rents” referred to are the financial surpluses accruing to the grid owner as a consequence of the price separation that occurs between network nodes where electricity is injected and nodes where it is consumed, because of transmission constraints. A consequence of grid congestion is that cheaper generation in an exporting region upstream of the constraint becomes “constrained off” in favour of more expensive generation (if available) in the importing region downstream of the constraint. While some cheaper generation will still be supplied to the importing region from the exporting region (unless the constraint is complete), exporting generators receive the lower price while all of the demand met in the importing region faces the higher marginal price resulting from the constraint. In consequence, a surplus accrues to the grid owner. In New Zealand this rent is rebated by Transpower to distributors via lower grid fees, so Leautier’s analysis suggests it is distributors who would ultimately bear the consequences of any generator market power expropriating those rents.

critical, and the significantly higher fixed costs of new generation can militate against this approach in favour of grid expansion.

*Is Market Power all Bad? – Static versus Dynamic Efficiency*

Before shifting attention to market-power issues in transmission and distribution, some final thoughts regarding generator market power are warranted. The MSC has expressed the view that the NZEM was in 2001 tending towards oligopoly, with the result that generator market power should be expected to be exercised from time to time, and one market participant argued that this should be expected with an efficient vertically integrated generator requiring a customer base of at least 300,000 customers (in a total market of 1.5 million residential, 130,000 commercial and 100,000 industrial customers). The tests from the NZEM's perspective as to whether such market power was unacceptable related to whether such market power was transitory or prolonged, and the extent to which it was predictable.

The exercise of some market power *per se* was not proscribed under the NZEM because it can in fact be “dynamically efficient” – providing necessary pricing signals to encourage competitive entry and new investment, and thereby maximising consumer welfare over time – even if short-term prices can be apparently excessive.<sup>21</sup> In supporting this view, the MSC noted that New Zealand electricity consumers are relatively immune to wholesale price surges during episodes of possible market power, and that NZEM wholesale prices were typically less than the long-run marginal cost of new generation (the level that prices should tend towards in a competitive market) – as supported by the analysis in Chapter 3. Indeed, perfect competition is not achievable for any part of the electricity system – retailing being the closest, but not serious, exception – given the sector's economies of scale, large and “sunk” fixed-costs, long-lived assets at risk of stranding, and only limited opportunities for bypass. As stated by Borenstein, Bushnell and Knittel (1999), in assessing the efficiency of any reformed industry it is not appropriate to contrast arrangements with the ideal of perfect competition, but rather with achievable alternative arrangements of varying degrees of imperfection. The costs of any market power in each case need to be weighed against the costs of market intervention.

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<sup>21</sup> Evans *et al.* (2003c) note the usual economic definitions of allocative and productive efficiency – respectively referring to the allocation of scarce resources to competing uses and the use of production processes minimising production costs, and also that of dynamic efficiency, referring to the efficiency of the framework for future decision-making. They note that the two former efficiency definitions relate to static measures of efficiency which can result in tradeoffs against dynamic efficiency. For example, in a statically efficient industry the operation of competition can be such that prices are driven to levels sufficiently low that no firm has incentive to innovate: “[i]n other words, under monopoly innovation occurs but at a lower pace than is socially optimal, whereas under [the ideal of] perfect competition there is none at all”. Such tradeoffs suggest rationales for the creation of monopoly rights such as trademarks and patent protections, assisting as they do the process of innovation that over time should be expected to benefit consumers. These authors conclude that the focus of public policy concerned with welfare maximisation should be on dynamic rather than static efficiency.

*Market Power in Transmission*

Transmission continues to be regarded as one of the more intractable examples of market power, both in the New Zealand electricity sector and overseas.<sup>22</sup> Whereas the re-evaluation of electricity-sector thinking that spawned contemporary electricity reforms has recognised the potential for generation to be structured in a competitive fashion (however imperfectly), transmission continues to be regarded at best as a sleeping dog in need of a muzzle. Such a characterisation stems from transmission being considered a “natural monopoly” (as opposed to the legal or statutory monopoly created by, e.g., state ownership of all generation), for which the efficient scale of production is such that only one firm can feasibly service available demand. As for monopoly generation, monopoly transmission suggests an ability to restrict output to raise prices, or simply to raise prices and allow consumers to respond as best they can to reduce demand and mitigate some of the impact of higher prices. In an interconnected grid the ability to withdraw capacity can be as simple as flicking a switch, or as subtle as imposing unnecessarily stringent grid-security standards, resulting in grid congestion and constraints giving rise to congestion rentals enjoyed by the grid operator in the absence of other arrangements (such as their rebating to grid-connected companies via reduced grid charges, as is done in New Zealand, in order to render the grid owner financially neutral with respect to congestion charges).

It is not entirely accurate, however, to characterise transmission in such plain terms. While it is often argued that it is not economic to replicate the national grid, this does not mean transmission is immune from competitive forces. Just as generation must to some extent compete with alternative energy sources (if not among generators), transmission is vulnerable to bypass in discrete areas – whether by actual or threatened replication of discrete transmission lines and equipment (e.g. by distribution companies), or by situating new generation sufficiently close to load that it can directly connect with distribution companies (e.g. “distributed generation” embedded in distribution networks) – should transmission charges sufficiently increase. Indeed, electricity transmission competes with gas transmission pipelines (either for final consumption, or to locate gas-fired generation closer to load). Since such alternatives are typically costly and slow to implement (although gas pipelines enjoy resource consent advantages over transmission lines), the extent to which any threat or action is credible is constrained.<sup>23</sup>

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<sup>22</sup> Here we concentrate on stand-alone transmission instead of transmission vertically integrated with generation and/or distribution, since electricity reform in New Zealand and typically elsewhere involves the separation of transmission from other market components. Leaving such “bottleneck” assets integrated with competitive activities in deregulated industries is more common in telecommunications, for which different regulatory issues arise. Structural separation involves a trade-off of economies of scale and scope – where integration allows for certain benefits not otherwise available – against the perceived benefits of market power reduction and competition enhancement.

<sup>23</sup> The main operator of New Zealand’s inter-island ferry, Tranz Rail, similarly relies on the ongoing threat of building its own southern ferry terminal to constrain charges on the locally owned terminal it currently uses at Picton. Planning consents and designs have been obtained, which maintain the threat’s credibility and simultaneously develop the option of carrying it out.

This affords transmission significant latitude in exercising any market power it might have, if there are no other constraints.

To the extent that the grid operator is not subject to market-based or other constraints on its use of any market power it possesses, the exercise of such market power has significant implications for the overall electricity system.<sup>24</sup> As discussed above, grid investment and operation are critical determinants of the overall competitive topology of an electricity sector. An unconstrained monopoly grid operator might wish to reduce or degrade capacity, or defer investment, to increase any congestion rents it receives. Alternatively, it might use its dominant position to impose unnecessarily stringent operating quality standards that constrain or deter bypass options. Furthermore, where a grid operator also has an interest in generation (i.e. is vertically integrated in the traditional mode), it can restrict economic access to competing generators wishing to wheel power to consumers across the grid (an issue resolved by separating generation from transmission, although at the cost of economies of scale and scope in coordination and investment that an integrated operator can enjoy). While any monopoly in transmission is not necessarily absolute, it can clearly be important.

#### *Incentives for Efficient Grid Investment*

An important issue in addressing transmission market power is creating appropriate incentives for either the incumbent grid owner or other potential grid investors to undertake efficient grid investments as and when they are required. In New Zealand an important step in at least providing the appropriate signals for new grid investment has been the adoption of nodal pricing, with differences in prices at nodes around the grid signalling the economic cost of transmission losses and congestion. However, grid owners are typically occupied by engineering issues such as operational security as much as they are with the economic costs of congestion.<sup>25</sup> In New Zealand, Transpower operates to the commonly used “N-1” grid security standard – meaning that “the lights should stay on” if any one major component in the network should fail. This is not the same thing as operating the grid to ensure the economic costs of losses and congestion are minimised, which would require an assessment of the relative costs and benefits to every grid user – over their respective operational lives – of supply security and price separation arising from losses and

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<sup>24</sup> It should be noted that while Transpower owns the grid it operates it as a contestable service provider to the NZEM.

<sup>25</sup> Indeed, to the extent the grid owner benefits from congestion rents (Transpower does not) it should be more than happy with this focus: keep the lights on but make sure the present value of grid-connection fees, usage charges and congestion rents are maximised while minimising operating costs and the costs of investment. In reality the potential for such gains can instead substitute inefficiency, managerial slack and lacklustre profitability for outright profit maximisation, simultaneously making it harder to detect monopoly behaviour and reducing the risk of regulatory intervention.

## BOX 9.1

## NZEM: One Market or Many?

Determining the degree of market segmentation in the New Zealand Electricity Market (NZEM) is made particularly important by the difficulty in detecting abuses of market power (see Box 9.2). Existing empirical approaches used for market power analysis, like simulation and bidding analysis, rely on the accurate measurement of the marginal cost of generation. Unfortunately, calculating the marginal cost is extremely difficult in the NZEM because of the high proportion of hydro-electric generation. This inability to detect non-competitive behaviour makes it all the more important that the market is conducive to competition. Given the number of firms in a pool market, competition is maximised if there are no transmission constraints or other phenomena that segment the market. This ensures that every firm competes with every other firm, which lessens the chances that market power can be exercised. Conversely, if the market becomes segmented, decreased competition may result, owing to the diminished market contestability and the consequent increase in concentration of ownership and control.<sup>26</sup>

By design, the price at every node in a perfectly integrated pool with no losses or constraints would be equal. The existence of constraints and losses will cause the market to segment and prices at different nodes to separate, hence the extent of integration is indicated by the extent to which prices at different nodes change together (i.e. if the market were integrated one would expect prices at different nodes to be strongly positively correlated, and lower correlations to be found if the market were segmented). Evans, Guthrie and Videbeck (2003a) use this insight, together with a statistical technique called factor analysis, to examine the degree of market integration present in the NZEM. The study looks at seven nodes throughout the NZEM and finds that all prices were frequently driven by a single factor, strongly suggesting that prices are highly correlated and that the market is usually integrated (notwithstanding evidence that the NZEM does segment from time to time). When such segmentation occurs, it is generally along North-South lines with the precise location of the split varying with the time of day. Such market segmentation usually occurs during periods of stress, such as peak periods or droughts. However, the study also suggests that the overall economic significance of such segmentation occurrences is small compared with the actual price, implying that firms in the NZEM are usually forced to compete with all other firms, an outcome which makes it difficult for firms to exercise unilateral market power.

<sup>26</sup> Even a segmented market may have sufficient competition amongst generators to achieve competitive outcomes; conversely even a fully integrated market can have market power issues (such as might arise from coordination). Nonetheless, an integrated market is always more conducive to competition, as a constrained solution cannot be more competitive than the associated unconstrained one.

congestion.<sup>27</sup> Clearly the informational requirements this imposes on a grid operator would in general be prohibitive, which argues for a market-based mechanism to allow the required trade-offs to be made by all market participants simultaneously, or at least some mechanism whereby the trade-offs are internalised by the parties making them (both discussed below) as opposed to the grid operator: it might be the “N-1” security rule of thumb, but it may not.

A difficulty with grid expansions undertaken by parties other than the existing grid operator is that they need not be efficient. As noted above, generators can prefer congestion as it enables the limitation of power flows from competing generators. The physics of electricity networks means it is possible to actually decrease transmission capacity by installing weak transmission capacity across some part of the network.<sup>28</sup> As such, it is important that inefficient investments of that type be prevented, or preferably that generator incentive for such investments be curtailed. Another difficulty is that any party investing in an efficient grid expansion cannot control the benefits from that investment, as other grid users will also enjoy the reduced congestion costs. Such “free-riding” can arise to the extent that the very constraints relieved by the new investment are re-introduced by other grid users increasing their throughput over the grid, meaning overall welfare is increased but the investing party might be left with insufficient net benefit to justify their investment.<sup>29</sup>

A possible solution to either of these complications involves the use of tradable financial instruments such as transmission congestion contracts (TCCs) or financial transmission rights (FTRs).<sup>30</sup> Defining a hedge over nodal price differences that measure the cost of grid congestion, such instruments protect their owners against price separation across network nodes.<sup>31</sup> If grid expansions are undertaken by parties other than the grid owner, then by offering such parties an FTR or TCC they are at least partially compensated for any nodal price separation arising from the reintroduction of congestion by other parties free-riding on the extra grid capacity. Alternatively they can be forced to accept such a contract to ensure they bear at least some of the cost of any inefficient grid expansion. Indeed, as surveyed and discussed in Evans and Meade (2001), FTRs can act either to discourage or encourage the use of market power by generators (or consumers), depending on the circumstances. For example, generators (or consumers) already enjoying market power who then acquire FTRs can find themselves with an

<sup>27</sup> An example of such tradeoffs being made is when Transpower relaxes its grid-security standard to alleviate tight supply conditions during winter demand peaks.

<sup>28</sup> Hogan (1999) gives the simple but illustrative example of a low-rated line being installed in parallel with an existing one-line network, reducing the overall flows possible since the maximum flow then possible is that across the weaker line.

<sup>29</sup> For a general discussion of network externalities see, for example, Liebowitz and Margolis (1994).

<sup>30</sup> An alternative, physical solution might be to separate AC networks into smaller AC sub-networks interconnected with DC connections – see Chapter 10.

<sup>31</sup> A discussion of TCCs and FTRs can be found in Hogan (1999), or Stoft (2002), with an analysis of the FTRs proposed by Transpower given in Evans and Meade (2001).

additional means to exploit that power.<sup>32</sup> Although they have limitations, an advantage of such instruments is that they create property rights whose value reflects the costs of grid congestion, and therefore represent a market-based means of signalling the need for, and providing incentives to encourage, grid expansions where they are most required (in economic rather than engineering terms).

### *Market Power in Distribution*

If market power is gaming's big ugly step-sister, distribution is transmission's irksome little brother. Like transmission, distribution (i.e. local lines operators) exhibits features of natural monopoly – with typically prohibitive replication costs, limited competition and possibilities of bypass from either adjoining network operators or self-generation; and with opportunities for strategic network access pricing to foreclose competition where distribution is combined with retailing or generation. At a more functional level distribution operators can foreclose competition by other retailers by not facilitating customer changeovers, imposing prohibitive (or stalling on posting) conditions which restrict competitor access through their networks, or using monopoly rents from distribution to cross-subsidise retail customers at risk of switching to competitors.<sup>33</sup> In New Zealand a number of these issues have been resolved by imposing prohibitions on lines owners also owning competitive activities such as retailing. There are also limitations on lines operators' involvement in generation, although recent reforms have allowed for greater involvement in distributed generation, particularly renewables-based generation.

### *Market Power in Retailing?*

It seems perverse to be discussing market power in retailing given that the thrust of electricity-sector reforms in New Zealand and elsewhere are intended to facilitate competition in sub-sectors now regarded as amenable to competition, typically taken to mean generation and retailing. While there are economies of scale in generation that can limit the number of competing generators possible in any given market, such barriers to competitive entry are not intrinsic to energy retailing – which is no more or less complicated than many other forms of commodity trading for which it would not normally be suggested that market power can arise.<sup>34</sup> Certainly market power enjoyed by retailers to the benefit of electricity consumers would not normally hit the headlines or perturb regulators and politicians.

<sup>32</sup> For example, a generator in an importing region who already benefits from congesting transmission to block competing generation from exporting regions would derive additional benefit from owning an FTR that hedges against price separation between the exporting and importing regions. Consumers in an exporting region face a similar incentive – the obvious example being South Island consumers, who benefit from an improved supply/demand balance when the HVDC link between the North and South Islands is constrained.

<sup>33</sup> See, for example, Reichmann (2000).

<sup>34</sup> Indeed, as discussed in Chapter 5, early evidence in Boshier and Gordon (1996) on the experience of energy retailers prior to vertical integration showed little or no margin being enjoyed, in no small part because they all faced common wholesale supply costs. Even with vertical integration, 2004 analysis by the Ministry of Economic Development suggested any increasing trend in retail margins was now broken.



For completeness, however, it must be acknowledged that market power issues can arise in retailing for possibly two reasons. The first, being artificial (and in reforming industries only transitory), relates to the presence of statutory franchise areas in which retail competition is precluded by law. The second, discussed earlier, is that the gaming of market rules is not the exclusive preserve of generators. With uniform-price auctions, for example, it is possible for demand-side collusion to reduce wholesale electricity prices, as was found by the England and Wales regulator to have occurred before the pool was replaced by NETA, or for day-ahead and real-time markets to be gamed by purchasers as was suggested during the California power crises.<sup>35</sup> While such manipulative behaviour benefits consumers in the short-run, in dynamic-efficiency terms it may reduce welfare by discouraging or at least deferring any required investment in new generation.

More so in other reforming countries where generators face limitations on their involvement in retailing,<sup>36</sup> the widespread integration of New Zealand generation and retailing might now be regarded as a manifestation of market power in retailing, if only by association. Indeed, the extent of generator and retailer integration in New Zealand is such that it can be argued that stand-alone energy retailing is not a viable business model (if it was even before vertical integration), not least because of generators' comparative advantage in managing the risks of changing wholesale electricity prices and transaction-cost advantages in delivering energy. With generators effectively hedging a significant share of their output by owning customer bases on relatively fixed price contracts (or at least prices slow to adjust to overall wholesale price levels), they have little electricity to offer competing retail-specific firms through the spot market or via long-term contracts – and such competitors would be vulnerable to any significant price movements in either. This is not to say that retailing is not competitive, since most consumers in New Zealand have access to at least two “gentailers” from which to purchase electricity, but the regionalisation of generation and load resulting from vertical integration once again highlights the importance of transmission constraints across regions in defining the scope and likely course of effective retail-level competition.

### *Testing for Market Power*

Before turning to questions of regulation, it is worth quickly discussing testing for market power. As with any test, failing to find evidence of market power is not evidence that it does not exist. Furthermore, tests that do identify market power might be mis-specified or poorly applied. False negatives are a risk, but so too are false positives: the former can result in undesirable conduct going unchecked, while the latter can give rise to inappropriate interventions with associated costs and distortions. In either case it is important to recognise the trade-offs between static and dynamic efficiency – any useful test for market power should consider forward-looking inter-temporal effects as much as static phenomena.

<sup>35</sup> See Michaels (2003) and response by Counsell and Evans (2003).

<sup>36</sup> Indeed, generators in England and Wales enjoyed increased access to regional electricity companies (RECs) partly by historical accident, as regulator-enforced generation sell-downs to encourage greater generator competition permitted REC acquisitions of generation, thereby conceding the principle.

A “textbook” approach to indentifying market power would focus on the extent to which prices diverge from marginal production costs, since the economic model of competition predicts that they should converge (certainly in the long run). The difficulty faced in implementing such measures is that while prices are observable, production costs are not (often even to the firm itself). Static measures such as the Herfindahl-Hirschmann Index (HHI) of market share concentration are more easily calculated, even though they bravely rely on market concentration correlating with excessive pricing and cannot capture the subtleties of market-participant behaviour (let alone transmission congestion). At the economic returns level, the profits – or more properly the cash flows – of firms suspected of having market power might be examined to gauge whether they are enjoying returns greater than those justified in risk-return terms.<sup>37</sup> Like industry concentration measures, these too are not especially reliable: highly competitive industries can include firms that, temporarily at least, enjoy periods of profitability greater than that required by investors to compensate for risk; and the assessment is only meaningful over the life of the firm’s operations, during which time significant “unders” and “overs” should be expected.

A more sophisticated approach to measuring market power – once again bedevilled by the problems of accurately estimating production costs but enjoying the benefits of being prospective and able to accommodate behavioural and strategic interactions – involves game-theoretic simulation models. Finding increasing application in electricity-industry research and evaluation, they attempt to model any divergence between prices and production costs over some forecast horizon based on assumed market-participant behaviour, industry structure, fuel costs, demand growth, location, etc. While conceptually superior to static measures, they too are vulnerable to mis-specification (not least in the New Zealand context because marginal production costs of electricity can vary considerably with the changing scarcity value of water). Typically they are unable to replicate the numerous complexities of even an existing electricity system – importantly, the complex dynamic optimisation represented by any electricity operation – let alone accurately foretell changes in industry structure, demand growth, weather patterns, fuel costs, or industry-participant strategies. Most of these influences will evolve with varying degrees of unpredictability, and might also involve elements of “learning” which a modeller will struggle to accommodate. A survey of this and other methods is given in Evans, Guthrie and Videbeck (2003b). They conclude that measuring market power in electricity markets remains a fraught exercise because the marginal cost of water is both hard to measure and inherently volatile, and also because of the oligopoly structure of generation with its attendant game-theoretic considerations.

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<sup>37</sup> In other words, whether such firms are earning a rate of return commensurate with the riskiness of their activities when compared with firms of similar risk, based on normative economic models of return such as the capital asset pricing model, and assuming that risk and return are the relevant objects of investor choice (*a la* Markowitz portfolio theory).

## BOX 9.2

## Some Approaches to Measuring Market Power ...

The difficulty in detecting non-competitive behaviour in electricity markets is often underestimated. For example, to many commentators, the sight of markedly higher wholesale electricity spot prices implies that prices are not competitive and that generators must be abusing market power. Some even see it as conclusive proof that deregulation has failed. The reasoning behind this is incorrect: although high prices are a recognised symptom of market power, their mere existence does not establish that market power is being exercised. Indeed, high prices may be indicative of a well-performing competitive market distributing a scarce resource efficiently and thus providing a reliable signal for current management and future investment. Even the high profit of an individual generator is not proof of its abuse of market power – high profits could result from a number of other factors, including superior generation efficiency (something a competitive market seeks to promote, not deter), temporary profits because of transitory circumstances, and profits that are required to meet the fixed cost of generation plant. The challenge is to distinguish between high prices and/or profits that are caused by the abuse of market power and those relating to normal market operation: it is not normal to observe zero profits in any market, particularly those that have only a few large firms and sunk costs, which is the case for electricity worldwide.

A number of empirical approaches, including direct and bidding analysis, have been developed to measure the unilateral exercise of market power, or more generally any inefficiencies, in electricity markets. It is important to note that both these approaches do not directly investigate the abuse of market power. Market power can be viewed on a continuum from perfect competition (unattainable ideal), to tolerable levels of unilateral market power (which are present in most industries), to the abuse of market power (which is to be avoided). When exactly the unilateral exercise of market power becomes an abuse of market power is a matter for continued debate. Indeed it is often contingent on the finding of intent.

Direct analysis (Wolfram (1999a), Borenstein *et al.* (2002), Joskow and Kahn (2002)) attempts to find the marginal cost of production of the price-setting generator for each trading period by building a hypothetical competitive market. It then compares these simulated “perfectly competitive” market prices (the theoretical ideal price) with the observed actual market prices. The more actual market prices exceed the estimated competitive prices, the more this points to market inefficiencies and the potential exercise of market power.

Bidding analysis (Wolfram (1998), Joskow and Kahn (2002)) takes a similar approach to that of direct analysis, except that it focuses on individual generators’ pricing/generation decisions. It does this by estimating the supply curve of

*box continues ...*

## BOX 9.2 CONT'D

## ... Some Approaches to Measuring Market Power

individual generators to see whether or not generators offer electricity at prices that exceed marginal cost or, equivalently, whether they do not offer in all the electricity that they could profitably generate.

Unfortunately the suitability of both direct and bidding analysis is questionable in any market because of the major difficulties surrounding the measurement of the marginal cost of reservoir generation, which includes the hydro-electric generation that provides approximately 60-70% of New Zealand's generation capacity; it is also relevant to gas-turbine generation (which contributes another 20%) when reserves are limited (see Box 3.2). In addition, direct analysis reduces the market into a single location – a simplification that could underestimate the simulated competitive price by ignoring inter-nodal constraints and transmission losses (see Box 9.1). Such uncertainty about the accuracy of the marginal cost estimates raises concerns that these approaches make it easy to misinterpret benign market events as the unilateral exercise of market power.

Source: Based on Videbeck (2004).

It is also useful to consider the anecdotal measure of market power receiving most attention in the public domain, namely episodes of dramatic increases in wholesale electricity prices. This has been especially contentious since the advent of the NZEM in October 1996 – particularly when wholesale prices rose significantly during the 2001 winter electricity crisis, when a winter crisis appeared imminent in early 2003 but failed to materialise, and when the HVDC link between the North and South Islands is sometimes lost owing to planned or unforeseen outages (as discussed in Chapter 6). In all such events commentators are quick to decry major price increases as a sign of market failure and/or market power abuse by generators, questioning how such high prices can be justified on grounds of production cost.<sup>38</sup> As noted by the MSC in NZEM (2001), such price surges are explicable and not inherently unreasonable. When short-term supply and demand – both relatively price-inelastic – are in close balance, for example because hydro reserves are scarce while demands are seasonally rising, even a small disturbance to that balance can result in markedly higher prices. This is not just an artefact of the NZEM pricing and dispatch model, but a reflection of the underlying economic fundamentals that to maintain balance between supply and demand it can be necessary to significantly increase prices (e.g. to induce interruptible load). The only reason a high market price results is because there are consumers willing to pay it.

<sup>38</sup> Curiously these cost-based arguments were not repeated when wholesale electricity prices fell almost to zero in March 2004 as a result of a hydro reserves being 134% of average – see “Megawatts Megacheap After Floods”, *New Zealand Herald*, 12 March 2004.

It might be argued that, in situations such as winter crises, generators unnecessarily withhold capacity in order to exacerbate this effect. However, the MSC has noted the “value to waiting” accruing to generators with scarce hydro (or other fuel) reserves in a period of tight supply and strong demand. In such cases, generators must manage their fuel stocks to optimally outlast the crisis period. They would receive little thanks if they committed all their reserves to early demands only to find they could not service later ones, in which case even higher wholesale prices should be expected. This value to waiting derives from the generators’ ability to better gauge hydro inflow, demand (weather-related and otherwise) and other uncertainties – and is an increasing function of such uncertainties. In the longer term, electricity prices should be expected to tend towards the long-run marginal costs of new generation; and to the extent that such prices exceed those levels – and the NZEM experience to date is that typically they do not – this would provide a greater indication of market power or some other form of failure.<sup>39</sup>

It is instructive to note that fresh vegetable prices soared in the lower North Island following summer storms and widespread flooding in February 2004. In some cases vegetable prices rose by 200%, which too might be said to represent an inappropriate divergence of prices from production costs.<sup>40</sup> The chief executive of the New Zealand Consumers’ Institute was reported to have said that nothing could be done about the situation, and that “supply and demand is a basic economic principle and, of course, the consumer is going to suffer”.<sup>41</sup> Should wholesale power price rises be regarded any differently, particularly when most electricity users are insulated from their effects?

## REGULATION

### *Nature and Motivation*

In plain terms regulation involves the control of some sphere of activity. As such it can encompass decentralised self-regulation as well as the centralised imposition of controls by an external party or parties. In the current context it refers to how the behaviour of electricity industry participants is controlled, whether to positive ends or to constrain undesirable behaviours. While it can encompass regulation defined

<sup>39</sup> This discussion highlights an important issue, namely the extent to which spot electricity prices are arguably “overworked” in the absence of liquid forward electricity, water, gas and other electricity fuel markets. Should those other markets be in place, forward prices would more naturally indicate anticipated future supply conditions, but in their absence current spot prices are the best available guide.

<sup>40</sup> Don’t even try to do the maths for a car park behind Harrods in London being offered for £100,000 (*The Dominion Post*, 26 February 2004), or the New Zealand embassy in Tokyo selling its tennis court for more than NZ \$300 million.

<sup>41</sup> “Storms Send Vege Prices Rocketing”, *The Dominion Post*, 26 February 2004.

by market participants in the form of, for example, self-determined market rules,<sup>42</sup> more commonly it refers to monitoring and control mechanisms imposed by a central regulatory agency to restrain or penalise industry conduct or performance deemed to be undesirable.

As noted by Steiner (2001), regulation in the electricity sector and elsewhere is typically motivated by concerns arising from the presence of natural monopolies, externalities and “public goods”. It is intended to substitute for competition where such competition does not otherwise arise. Natural monopoly issues as they arise in transmission and distribution have been discussed earlier in this chapter. So too has the issue of externalities, meaning the effects experienced by some parties as a consequence of the actions of others, in the context of network interdependencies also characterising transmission, and, to a lesser extent, distribution. Public-good issues (my consumption of the good does not preclude yours), non-excludability (everyone can consume the good), and impossibility of rejection (consumers can’t opt out of consuming the good) also apply to grids and networks.<sup>43</sup> On the face of it transmission and distribution are obvious targets for regulation.

### *Purpose*

Having said this, important questions remain. What is the purpose of regulation? More specifically, what is the evil to be avoided? More tellingly, are the costs of regulation – the direct costs of its imposition as well as the fundamentally more important costs of the economic distortions they can create – more or less than the costs they seek to reduce? And is the process of regulation, as well as the method, likely to be effective or counter-productive?

As to the first two of these questions, the answer is typically the avoidance of the distortions and welfare losses associated with the exercise of market power. In generation this is taken to refer to gaming (which we have distinguished from market power *per se*), and at worst it includes collusion. In addition, regulators may consider outcome-based measures such as electricity prices or profits (or increases in either) as inappropriate in some sense. In transmission and distribution it not only refers to excessive prices or profits (or increases therein) but also to the use of pricing or other devices to limit competition across grids or local networks. In retailing it less commonly refers to price gouging (except where franchise areas are still in place) or

<sup>42</sup> Prior to the Electricity Commission taking responsibility for NZEM governance on 1 March 2004, the NZEM was remarkable for having industry-determined market rules, as well as voluntary agreement by NZEM participants to subject the enforcement of market rules to a market surveillance committee comprised of independent, non-industry members – see Arnold and Evans (2001).

<sup>43</sup> This grid characteristic, and that of externalities, is at least partially or imperfectly resolvable by the creation of transmission property rights such as TCCs or FTRs, or through separation of AC networks into smaller AC sub-networks interconnected via DC links. The problem with public goods is that everybody wants them (or cannot be excluded from consuming them), but it is difficult to price them and elicit payment for them. Creating private property rights over public goods, where feasible, is the natural remedy – the “missing market” justification for deeming goods “public” simply begs the question.

market power exercised by consumers (which is typically seen as a lesser evil than that exercised by generators). In New Zealand it increasingly refers to actions (or inactions) by “gentailers” that some may regard as structural obstacles to entry by competing retailers, and also as having undue scope to influence electricity prices available to larger customers (through either the spot market or long-term contracts).

### *Some Theories of Regulation*

A review of the theories of regulation is well beyond the scope of this work, but a few broad summaries are presented for context.<sup>44</sup> Dnes *et al.* (1998) characterise regulatory theories as falling into three camps: the “public interest” approach of Demsetz, the “private interest” approach of Weyman-Jones *et al.*, and the “mixed” view of Posner *et al.* The former follows traditional welfare economics and sees regulatory intervention by an impartial (and wise) government as a means to maximise social welfare in the face of natural monopoly. The second sees regulation as a means to balance competing private interests (e.g. as between a private monopolist and others), giving rise to the “regulatory capture” theory of Stigler *et al.* in which vote-maximising governments allow regulation (or even legislation) to be swayed by lobbies and other interest groups of varying shades. The final view suggests regulation should be seen as benefiting some at the expense of others, representing a mechanism of redistribution. Evans (1998) adds to the redistributive view by noting how regulation is often a mechanism for government to direct industries towards social ends, such as “universal service” in telephony.

Applying the “event-study” methodology from financial economics<sup>45</sup> to assess the impact on regional electricity companies (RECs) of regulatory interventions in the England and Wales electricity system between 1990 and 1995, Dnes *et al.* (1998) find an overall pattern of positive abnormal returns to RECs from regulatory announcement. They hesitate to regard this as regulatory capture; rather they attribute it to settings that were more favourable than expected. As noted in Chapter 4, REC regulation in the earlier period of the England and Wales reforms was regarded as possibly being too tentative, which is consistent with these findings, and was followed by a period of more aggressive regulated price reductions (for both distribution and, where still subject to franchise area monopolies, retailing). Interestingly, these researchers document adverse REC share price reactions in response to controversial regulatory interventions, indicating the potential for regulation to adversely affect the value of distribution investments whether intentionally or not.

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<sup>44</sup> Appendix 9.1 provides a comparison of the leading regulatory alternatives, and discusses their respective merits and shortcomings.

<sup>45</sup> Event-studies examine the share price reaction of companies to the announcement of “events” of interest to gauge whether shareholders in such companies regard the events as adding to or detracting from the long-term value of their investments. The reactions are measured by “abnormal” returns – positive or negative – calculated by subtracting from observed price movements an allowance for risk-adjusted share price movements occurring at the same time. In this way the company-specific impact of the event can be distinguished from other relevant market-wide events.

Crew and Kleindorfer (2002) ascribe to the redistributive/regulatory capture view of regulation, with a monopolist's excess profits being reallocated by some process to others, noting that the impetus for deregulation has been in part born of economists and wider society becoming "more sceptical about the Nirvana view of government". While suggesting this motivates a shift away from the public-interest approach, they note this does not mean that deregulation (or reforms tilted in favour of market mechanisms and less government involvement) will be free of private-interest considerations – what might be termed "reform capture". Deregulation, they argue, will remain redistributive and hence the subject of ongoing private-interest influence, with producers seeking reform gains at the expense of consumers, and large consumers seeking to gain at the expense of the small. Such cynical characterisations bear scrutiny given the recent Californian reform experience (e.g. utilities being compensated via electricity prices for stranded costs in a supposedly deregulated context). In any case it should be clear that regulation is commonly regarded as something other than a pure process motivated simply by maximising overall welfare. It arises in a political context that has the potential to create significant economic distortions if it is poorly motivated, designed and implemented.

### *Regulatory Approaches*

As mentioned above, regulation can range from rules self-imposed by industry (which might be competitive or anti-competitive in effect) through to those imposed by some external – usually government – agency (which similarly can be of varying competitive effect).<sup>46</sup> Focusing on the latter, Armstrong *et al.* (1996) suggest four possible approaches: (1) the regulator determining how a regulated entity (e.g. grid operator) will set its supply price, terms and conditions; (2) the regulator offering the entity a range of regulatory schemes from which it chooses one; (3) the entity being subjected to some overall regulatory constraint (such as capped revenue growth) but otherwise being allowed to set its price, terms and conditions; and (4) the entity being subject only to general competition law (i.e. no industry-specific legislation).

The latter is an example of "light-handed" regulation that has characterised the approach in New Zealand for most of the past two decades – since the advent of the Commerce Act 1986. Evans (1998) characterises this approach as one in which government establishes a property rights and competition law framework, but otherwise relies on self-regulation by industry on the strength of the threat of competitive entry to rectify any incumbents' misbehaviour. As a last resort government retains the ability to intervene more heavily should self-regulation be seen to be inadequate – but by keeping this power in reserve it reduces any distortion created by explicit regulation, albeit with some loss of regulatory

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<sup>46</sup> As noted in Chapter 4, US rate-of-return regulation in the early 1900s can be regarded as an attempt to constrain competition rather than abuse of market power. Various industries often call for regulation (such as entry standards for medical practitioners) which on the face of it appear well motivated by concerns for (e.g.) public safety or the needs for quality standards – but which in effect raise entry barriers that stifle competition and/or increase the market power of those satisfying the regulations (and for these and other reasons can even be self-defeating).



credibility. Evans, too, lays out a succession of regulatory options, from government recognition of self-regulation by industry and “heavy-handed” regulation of private operators through to direct government provision (and hence ownership of the means of production, often in the form of state-owned monopolies). While Vogelsang (2002) describes New Zealand’s approach of the past twenty years as representing “total deregulation” at the “most extreme” end of the regulatory scale, in reality deregulation has been mixed in character, with aspects of all four approaches evident throughout its course. Indeed, more recent initiatives see it moving squarely in the direction of heavy-handed regulation combined with a high level of state ownership (and with increased vertical integration since 1999).

As noted in Chapter 5, light-handed regulation of transmission and distribution in New Zealand has been based around mandated disclosures of network operators’ returns and “optimised” assets only, calculated using the so-called optimised deprival value (ODV) methodology. Where network operator returns are revealed to exceed a “fair” return based on the returns expected of businesses with similar risk characteristics, it was intended under the light-handed approach that pressure from consumers and others, backed by the threat of activating price control provisions latent in the Commerce Act 1986, would be sufficient to deter over-pricing. In reality the regime shared some of the failings of more explicit rate-of-return regulation – with some constrained incentives for cost efficiencies, and generally an inability to reveal excessive pricing and/or inefficient operations.

## OWNERSHIP REFORM – THE NEGLECTED REGULATORY COMPONENT?

### *State Ownership as a Defence against Market Power*

Electricity reformers in New Zealand and elsewhere have long been aware of the potential efficacy of ownership as a means of reducing market power or mitigating its effects. For many years state ownership of monopolies has been regarded as a suitable hedge against price gouging, with “society” apparently reaping any of the ill-gotten benefits, particularly where state ownership was seen as permitting objectives other than profit-making. Increasingly it is recognised that this model instead includes incentives for waste, conflicting objectives, undue influence by particular political interests, and income redistribution from consumers to taxpayers in ways that distort consumption, investment and employment patterns (relative to desirable and achievable alternatives). It also presents an obstacle to industry innovation by deterring the entry of new operators, thereby leaving taxpayers as owners with the risks of any new investment and changes in technology.

### *Profit Motive Aids Regulation*

This is not the place to review the often-times controversial issue of government ownership versus ownership by the public by means of holdings of (listed) equity. Nevertheless, the efficacy of regulation and, most would argue, the performance of the industry is significantly

affected by ownership and so it behoves some discussion.<sup>47</sup> Protagonists in any debate will generally agree that, in an economy enforcing property rights, publicly held corporations are more single-minded in their pursuit of profit over time than are government-owned entities. Willig (1993) argues that for this reason the objective of publicly held firms is better defined and known and hence the response of the firm to regulation is better understood by any regulator. As a consequence, more effective regulation can be designed for publicly held firms than for government-owned firms. In addition, competition among and for publicly held firms is on a different plane from that of government-owned entities: the ability to compete for ownership is one material dimension of competition that is relevant for performance and is missing in government-held entities.<sup>48</sup> The ownership by the public of shares in a government-controlled entity is a sort of halfway house that affects a firm's choice of and focus on objectives, and increases the extent of information disclosure and monitoring of its activities.

### *Ownership Reforms to Date*

In the context of the contemporary reforms, ongoing state ownership of most generation and all of transmission in New Zealand has been a political default rather than deliberate policy instrument. Ownership reform at the community and even private level, namely that of combined distributor/retailers, was recognised as being potentially inimical to retail-level competition and private investment in generation. It was for this reason that government imposed ownership restrictions in 1999 preventing lines owners from also owning competitive activities such as retailing (and all but a small amount of generation). By such ownership and legal-form separations (i.e. the separation of transmission from generation), New Zealand has adopted some of the more potent means of eliminating or at least mitigating various manifestations of market power. Indeed, it has done so at the cost of economies of scale and scope that continued integration can bring – and at the risk of creating property-right insecurities that prejudice long-term investment returns. It has judged that the competitive gains outweigh these costs.

As identified earlier, the vertical integration of generation and retailing occurring since 1999 potentially represents an obstacle to further competitive entry by retail-specific firms, but any move to impose requirements on generators to offer portions of their capacity via long-term contracts may – for better or worse – put retail business back in play. More problematical, however, is the relative entrenchment in lines-company ownership that has resulted from the reforms. Given local authority ownership of lines companies for many decades, it was perhaps inevitable that parochial interests would present an obstacle to rationalisation in a sector that remains over-populated despite having halved in number since the reforms began

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<sup>47</sup> The recent comprehensive OECD (2003) review of privatisation reports that “[o]ne of the most important policy objectives of privatisation is to improve the efficiency and performance of companies. Despite the difficulties with data and methodologies there is overwhelming support for the notion that privatisation brings about a significant increase in the profitability, real output, and efficiency of privatised companies. The results on improved efficiency are particularly robust when the firm operates in a competitive market, and that deregulation speeds up convergence to private sector levels”.

<sup>48</sup> For commentary on these issues and Willig's (1993) proposition see Evans (1999).

in 1987.<sup>49</sup> Following the ownership reforms imposed with the 1999 separation of distribution and retailing, 27 out of 28 lines operators have some degree of community- or customer-trust and/or local-authority ownership – 20 are wholly trust-owned, one is a customer cooperative, and public ownership arises in just two companies.<sup>50</sup> On the enforced split of lines and energy in 1999, most retail (energy) companies were sold and the lines element of the business retained in some form of trust or local government ownership.

### *Community or Consumer Ownership of Distribution*

Community ownership of local lines businesses replicates the central-government ownership of monopolies and thereby provides a measure of protection against monopoly pricing. If the lines company overcharges its customers, to some extent the customers will enjoy the benefits from those excess profits in other ways. Indeed, because the interests of communities that own local lines companies should be more closely aligned with their representatives than central government's will be with those of all electricity users, local ownership represents a potential efficiency gain over central-government ownership.

Cooperative and consumer-trust ownership – where distribution company profit payouts are rebated or otherwise largely distributed directly to electricity customers – may represent a relatively more efficient form of ownership in the face of monopoly profits.<sup>51</sup> In these cases there should be a material correlation between excess prices borne from monopoly lines pricing and compensatory rebates to mitigate their effects, and those with the greatest interest in efficient investments have incentives to involve themselves in the investment process.<sup>52</sup> In all other cases of community ownership no such correlation can be assumed, and hence the mitigating effects of local/community ownership are likely to be highly attenuated, to the point of being ineffective,<sup>53</sup> unless it is to use lines company profits as alternatives to local

<sup>49</sup> New Zealand has 28 lines operators in a country the size of the United Kingdom (which has 12), but with only 7% of the population. Similarly, the Australian state of Victoria has just five distribution companies, a fraction of the number pre-reform. Based on operating cost data from the 1980s cited in Evans (1998), and operating data in PricewaterhouseCoopers (2003), only four distribution companies out of 60 (i.e. 7%) were of sufficient scale to enjoy lowest-possible operating costs before the reforms; in 2003 that figure had risen to only five out of 28 (i.e. 18%). While such an analysis can obscure very real reasons for differences in lines-company configurations, it can still be suggested that in many cases operating efficiencies in distribution remain to be achieved.

<sup>50</sup> Section 38 of the Electricity Industry Reform Act 1998 defines customer trusts as trusts whose income beneficiaries substantially comprise persons identified by reference to various measures of electricity usage, and community trusts as those whose income beneficiaries substantially comprise persons identified with a particular locale.

<sup>51</sup> In this regard the extension of the option for lines businesses to be cooperatively owned under the Electricity Industry Reform Amendment Act 2001 is to be welcomed.

<sup>52</sup> Questions of governance become especially important. If cooperative or customer-trust governance can be hijacked by interest groups, then distribution rules can be distorted or investments undertaken in the interests of some when others are more warranted. In this regard the Electricity Amendment Act 2001's provisions for improving trust governance are both long overdue and a step in the right direction. Another possibility is to allow for a significant level (i.e. around one-third to one-half) of private ownership of lines businesses, as a means of imposing capital-market-governance disciplines on their management. While this compromises the anti-market-power hedge created through exclusive customer ownership, it does so to the benefit of improved governance. An additional measure could be to outsource physical network management as a means to secure operational efficiencies as well as to simplify performance measurement and contracting.

<sup>53</sup> If you use a lot of electricity, then you'd better swim at a local aquatic centre or play on a local sports team.

authority rates. It is perhaps for this reason that political attention continues to be paid to lines company pricing through the Ministry of Economic Development and New Zealand's price-regulatory body, the Commerce Commission, despite the fact that the communities they are apparently inclined to overcharge are their owners.

The purpose and effect of such regulation is quite unclear since it seeks to do what the ownership structure – in many instances – is designed to do. And where ownership is not designed to mitigate market power, it is attempting to regulate in the presence of multiple objectives, in which case Willig's theorem applies (i.e. profit-motivated firms are easier to regulate than other organisations because their objective functions are more easily specified). In New Zealand the value of community investments in lines companies faces the prospect of erosion by unnecessary regulation, or even increased risk of bankruptcy (not least because trusts are constrained in their ability to raise new equity as required). In that case electricity consumers not only fail to enjoy the mitigating effects of ownership on monopoly, but the value of their community asset is potentially reduced by regulation. Presumably it is for these reasons that the majority of cooperative distribution companies in the USA and Canada are exempt from such regulation.<sup>54</sup> Meade (2005b) argues that the regulation of customer-owned monopolies is inferior to unregulated customer ownership, and that even unregulated non-customer ownership is possibly also superior.

#### *Ownership of Transpower can be Bettered*

Finally, similar reasoning suggests that the current ownership structure of Transpower is not as efficient as it might be. At present it is 100% state-owned, and required to earn a commercial rate of return on its network ODV subject to efficiency and other objectives. Both of these features represent a far from necessary or sufficient solution to the problem of monopoly transmission. Transpower's pricing has been subject to the oversight of the Commerce Commission, despite the company's absence of a profit-maximising objective, and with the recent transfer of Transpower's pricing and investment policies to the new Electricity Commission – effectively a government bureaucracy more removed from the costs and benefits of transmission mis-pricing and investment than industry is – this state of affairs is not improved. Other models merit consideration.

#### *US Models of Grid Ownership*

In the US, transmission grids have typically been owned by private utilities and vertically integrated with generation and distribution/retailing. Rate-of-return regulation, and increasingly incentive regulation, has been used to protect consumers (however successfully). Interconnections between grids traditionally arose voluntarily (i.e. to wheel wholesale electricity between states), but federal regulators in 2000 sought to encourage more open and non-discriminatory arrangements. As discussed

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<sup>54</sup> An indication of the position of cooperative distribution companies in the USA is given by Burr (2004).

by Tomain (2003), this involved the mandating of regional transmission organisations (RTOs), which could take the form of non-profit independent system operators (ISOs), or for-profit independent transmission companies (Transcos). The former, run by non-owners, are predicted to price reasonably and maintain short-term reliability (the PJM interconnection follows this model). The latter, being owner-operated, are predicted to be superior in terms of investment and long-term reliability, and in terms of planning, innovation and maintenance. Importantly, each can accommodate consumer protections in the context of private grid ownership.

#### *England and Wales Model of Grid Ownership*

As discussed in Chapter 4, in England and Wales the national grid company was privatised after initially being owned by the regional distribution companies, and was subjected to price caps to guard against monopoly abuses. In fact the privatised grid company is subject to price caps on both its network revenues (Transmission Asset and Owner, or TO, price control) and balancing services revenues (System Operator, or SO, price control). In setting price caps (using RPI-X) the electricity and gas regulator, Ofgem, estimates the revenue required for an efficient transmission business, taking into account allowances for operating expenditure, capital expenditure, financing costs (based on an allowed return on a regulatory asset value – compare this with rate-of-return regulation), and taxation. Caps are reviewed five-yearly, but provision is made for adjustments before cap reviews, via so-called “income adjusting event” provisions under the SO price control and via an “annual correction factor” under the TO price control for unplanned output variations. The model is one that accords with the Willig test: a private firm regulated by a standalone regulator, providing good information disclosure, some incentive for cost-efficient operation, and an objective function that the regulator can assume with some confidence.

Such price controls are estimated to have resulted in £1.25 billion being transferred annually from gas and electricity businesses to their customers, while network investment has exceeded £30 billion under the regime.<sup>55</sup> Issues have arisen with the need to prematurely consider cap reviews to accommodate unanticipated grid investments and so facilitate investments in renewable generation, but without mitigating incentives for efficiencies or encouraging gaming of review periods. Concerns have also been raised that the periodicity of reviews favours the grid operator achieving efficiency gains early in the price-control period, since later gains are enjoyed only until they are passed to consumers via revised price controls. This can also encourage gaming of reviews by deferring the realisation of efficiency gains. Another concern is that the regime has weaker incentives for capital efficiencies than for operating efficiencies (i.e. has a bias towards grid capital expenditures). With private ownership of the England and Wales grid, concerns about monopoly pricing have been addressed by imposing price controls that are intended to allow the grid owner/operator operational independence while encouraging efficient operation and investment. The approach appears to have

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<sup>55</sup> Ofgem (2004a).

achieved broadly satisfactory results in line with the stated intentions, but it is not without difficulties. It carries within itself an ongoing tension between the regulator and its better-informed grid owner/operator counterpart, and so provides incentives for regulatory gaming. This is inevitable in price regulation.

#### *Other Grid Ownership Models*

As in England and Wales, in Victoria the state transmission grid has also been privatised. Unregulated “entrepreneurial” or “merchant” inter-state grid connections are also now part of the new National Electricity Market. In Germany, shareholder-owned companies now own the six national grid utilities that had previously been in local ownership. In instituting these reforms, the associated taxpayers have enjoyed significant privatisation proceeds while also being protected against monopoly pricing via regulated transmission price reductions. At the same time they have been relieved of the risks of future grid investments. New Zealand’s solution is far from this.

#### *“Club” Ownership of Transpower Shelved Despite Promise*

Leaving aside privatisation, New Zealand shelved an alternative ownership reform opportunity for transmission that has the potential to both materially diminish concerns about monopoly pricing and enhance incentives for desirable grid investment. As long ago as 1989 it had been proposed that transmission be owned by a “club” of generators and distributors, a proposal that lapsed with distributor opposition to having to buy the grid assets and political sensitivity to being seen to privatise the grid (even if it was then to local-government-owned distribution parties).

For the reasons cited above regarding cooperative and customer ownership of distribution, there are arguably significant natural advantages to distribution companies owning transmission. This is even more so if distribution companies are in turn cooperatively or customer-trust owned. Most obvious is the ability to mitigate any effects of monopoly pricing in transmission, thus reducing the need for inherently problematical regulation. Those who might be gouged are those who share the benefits of any gouging and, as long as governance and distribution rules are appropriately provided for, these two influences should be largely off-setting and pricing policy issues relating to common cost allocations most naturally resolved.<sup>56</sup> Additionally, with an amended version of the “club” as discussed in Chapter 10, those bearing the costs of grid congestion are also those in the best position to devise and implement suitable grid investments. Such advantages need to be weighed, however, against the governance gains, clearer objectives and greater capital access available through listed public ownership of regulated transmission.

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<sup>56</sup> It must be acknowledged that resolving common cost allocations is no small matter. The point being made is that these allocations can be determined administratively by a party not most exposed to the consequences of any errors, or more directly by those with the best information and incentives to ensure an appropriate outcome. It is suggested that distributor-ownership of transmission moves us closer to the latter.

*Models Compared*

In both the cooperative and the publicly-held-but-regulated firms we have not specified, but we presume, a Transco model wherein the grid owner and system operator are imbedded in the same entity as they have been, for all intents and purposes, in the NZEM (where they are owned by Transpower). The alternative approach is to have an independent system operator (ISO) separate from the grid that manages security and dispatch of energy and is held in a way that it does not profit from the performance of the grid or dispatch. Independence provides for contestability of this function, but the services of the grid require the coordination of grid performance and dispatch of generation – coordination that is arguably more effective in the Transco model. Where coordination of dispatch extends beyond one grid to encompass grids of other owners, this argument for superior coordination of the Transco model is reduced. It may also be less persuasive when all generation is forced to be placed through the pool, as in the hitherto version of the NZEM. In the Transco model one entity, the grid owner, is responsible for the totality of transport services related to the grid: these, again arguably, are the services that generators and demanders seek, and performance can be achieved by the incentives of a publicly held firm subject to regulation or the cooperative model.<sup>57</sup>

Together with greater distribution-company rationalisation, the issues around ownership, governance and consequent regulatory refinements could be said to be the most significant piece of unfinished business in New Zealand's electricity reforms.

## SOME REFLECTIONS ON THE NEW ZEALAND ELECTRICITY REFORMS

*Market Power and Gaming neither Universal nor Damning*

New Zealand is not alone in facing issues of gaming and market power in its reformed electricity sector, since the economics of electricity provision suggest that some measure of oligopoly or even monopoly is to be expected. While gaming is susceptible to being remedied by changes to market rules and other arrangements, a degree of market power in generation (and sometimes in demand) is to be expected despite significant steps having been taken to engender competition through successive generation break-up and the implementation of a wholesale market. At present the exercise of market power appears to take the usual forms observed elsewhere. But this exercise is transitory and not systematic to any significant degree – as evidenced by the fact that wholesale electricity prices have been typically less than the level required to induce entry by new generation, although the not insignificant entry costs of new generation create a margin above wholesale prices that could be sustained for a time before new entry becomes viable. Expressions of market power (to the extent they have already arisen) are not automatically signs of reform failure or welfare loss: they may be signals

<sup>57</sup> See Henney (2002) for a critique of the ISO approach.

of temporary situations and must be compared to an appropriate counterfactual (e.g. return to state-owned monopoly or some other form of central planning), and continuing private-sector generation investments (see Chapter 10) suggest they are not in themselves dynamically inefficient.

#### *Privatisation Feasible but Unpalatable*

Until generation break-up and the advent of the wholesale electricity market – along with separation of transmission and generation being preconditions for market power to be tamed if not eliminated in generation – it was not desirable, let alone politically feasible, for state-owned generation to be privatised. In this regard the sale of Contact to private investors in 1999 represents “one against the game”. While more widespread privatisation of generation is not currently to be anticipated (privatisation is the policy that dare not speak its name), at least there are now few inherent policy obstacles to this should it be desired.

#### *Transmission Issues Remain*

The beast of monopoly transmission is not yet tamed, despite the recent imposition of price caps on transmission and its pricing and investment policies being assumed by a government regulator. Even if these measures prove to be effective, they are likely to quell any appetite for private-sector ownership of transmission and investment. They represent a potentially inferior solution to either the well-specified regulatory model suggested by Willig’s proposition or the “club” model (in fact, a revised “club” model – see Chapter 10), long-since shelved. By deterring private ownership of transmission, they imply ongoing taxpayer investment and risk-bearing that might otherwise be burdens falling more directly on those enjoying their benefits.

The importance of transmission capacity in defining or limiting generator and transmission market power provides a useful counterpoint to current government policy favouring investment in distributed (particularly renewable) generation. Representing a reversion towards an industry architecture pre-dating New Zealand’s transmission grid, it is intended to take the pressure off the need for grid expansions by allowing local communities to generate their own power and bypass the grid by wheeling it directly through local lines networks. Owing to neglect of transmission investment, what it may result in is a further regionalisation of the electricity system – at the cost of nationwide competition. At the same time shifting the burden of determining transmission investment policy to the new Electricity Commission has the capacity to make or break the future competitive topology of the industry, while attenuating the ability of those bearing the costs of this to materially involve themselves in the solution process (see Chapter 10 for more). And at a more subtle level it represents a reversion to central planning for determining the generation mix, with fashionable energy sources receiving preference over the more obvious – New Zealand has enough coal to produce electricity for centuries – and ignores the



possibility that technology gains will render currently inappropriate generation types at least as efficacious as others.<sup>58</sup>

### *Limitations of ODV Regulation*

New Zealand's light-handed regulation of distribution companies based on information disclosures and the ODV methodology – combined with obstacles to ownership reform discussed earlier – has either delivered limited efficiency gains, or has resulted in consumers possibly benefiting little where such gains have been achieved. Bertram and Twaddle (2003) argue that the four major lines companies at the forefront of industry rationalisation – United Networks, Vector, Powerco, and Orion – indeed secured significant unit-cost reductions over 1992-2002, while all other companies achieved only modest unit-cost savings. On the other hand, these authors argue that all lines companies experienced increasing average revenue: this suggests widening price-cost margins over this period, a measure indicative of market-power exploitation. They further found that lines businesses enjoyed excess profits compared with those justified by their weighted-average cost of capital.<sup>59</sup>

While the adoption of ODV methodology removed the incentive to “gold plate” under traditional cost-plus regulation and did not pass on the costs of stranded investments to consumers, at the same time it did not spur lines owners to efficiency gains or encourage investments (particularly those at risk of becoming stranded). Perversely, where lines operators had high prices and returns, the ODV methodology was indifferent to more normal returns being achieved by either lowered prices or increased costs. Conversely, where efficient operators enjoyed high returns despite low prices, it suggested they should lower prices or not bother to secure further efficiencies. The approach was relatively free from political interference and risk, and arguably was superior to traditional rate-of-return and formal incentive regulation, but, in common with any price-regulation scheme, offered weak incentives to motivate lines operators or reward their customers.<sup>60</sup>

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<sup>58</sup> Recent reports indicate the potential for coal to be used to produce hydrogen for fuel-cells, producing water as their only waste product. Technologies are also now emerging for scrubbing carbon from carbon oxides, implying that coal may one day be regarded as both an environmentally acceptable and a renewable energy source. Over very long timeframes coal is already a renewable energy source (cf the “carbon cycle”); with new technologies this may be the case on a more useful time-scale.

<sup>59</sup> One caveat regarding this conclusion is that the excess returns were based on accounting asset revaluations having been taken to profit. While increased asset values, ODV in particular, could be taken to justify higher future lines charges and profits under the ODV methodology, these were not associated with actual current increases in charges. In other words, the measured excess returns are possibly more an accounting artefact than actual, and with the recent shift to incentive-based regulation based on CPI-X price caps that potential must now be constrained.

<sup>60</sup> The exception to the latter, as discussed earlier, being where trust- or cooperative-owned lines companies rebated profits to their beneficiaries or customers respectively.

Had more widespread rationalisation of distribution companies arisen, and efficiencies been achieved and shared with customers, this might have obviated much of the perceived need to move from the ODV regime to price caps, but this is doubtful. In New Zealand, distribution reform was (and remains) potentially constrained by parochial and diffuse ownership – as it was in the US, where vertically integrated utilities with stranded assets represented an obstacle to radical sector reform (i.e. requiring compromises of the sort that were so telling in California); but as it was not in England and Wales, and in Victoria, where government ownership of distribution provided it a degree of freedom to rationalise distribution as it saw fit. Ironically, government has been willing to implement reforms that touch on local ownership of distribution as if it were equivalent to central government ownership (e.g. the 1992 and 1998 reforms), but it has not been willing to address questions of Transpower’s ownership.

### *Over-Regulation of Distribution*

With determination of distribution company ownership at the time being left to local interests, it was perhaps inevitable that distribution reforms would be difficult. That communities continue to think community-trust ownership is somehow an efficient means of mitigating market-power concerns, or a necessary means to preserve local lines assets in their control, suggests a possible misunderstanding of both the risks and the opportunities. Under current structures neither goal is well achieved. With the introduction of price caps on lines operators, these operators potentially get medicine they don’t need (because more efficient ownership would suffice), face an unnecessarily increased risk of bankruptcy (should caps prove too tight), and suffer side-effects from their ownership interest (fewer community swimming pools because of reduced lines-company profits) which must be traded against any lines pricing benefits they enjoy. The longer-term effects of price controls on network investment remain to be seen.

### *Distribution Regulation in Context*

Finally it is worth placing New Zealand’s fixation with taming local-monopoly lines businesses in context. Not only do distribution costs represent a fraction of domestic power bills, but, as indicated in Chapter 7, those power bills represent around only 3-5% of average weekly household expenditures. Most New Zealanders spend more on takeaways each week than they do on network charges. More to the point, however, no-one seems to level the criticisms aimed at distributors (and telephone network operators) at providers of other utilities that are clearly at least as “essential” to health – namely water reticulation and sewerage.<sup>61</sup>

In New Zealand both are typically provided as local-authority monopolies, without clear financial reporting, performance monitoring or often-times even separate pricing

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<sup>61</sup> Admittedly the potential for bypassing either is higher than for electricity distribution (you can buy bottled water or get into composting), but all share the bugbear of high fixed- and low variable-charges, which are apparently so burdensome on household budgets.

(they are commonly included in local-authority rates). Water reticulation, in particular, is often subject to supply security issues – with many communities often facing supply shortages in the face of droughts, and it is not uncommon for water supplies to be cut because of pollution (e.g. sewage spills after heavy rains, toxic algae, or infestation by other pathogens). Where moves have been made to increase efficiencies in this area – such as Auckland contracting out management of water supply to a private operator and/or with water meters being introduced – these steps have often been decried as merely presaging the unspeakable privatisation. Given local-body politics, it is perhaps unavoidable that implicit and unregulated price and quality gouging by inefficient monopolies which are hard to monitor (let alone control) will be preferred to the perceived perils of competition and efficiency gains achievable by introducing private ownership and competitive disciplines. Other countries or states reforming their electricity systems have not been so constrained – or their reform imperatives have been sufficient to overcome such objections.

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**APPENDIX 9.1 – COMPARING REGULATORY ALTERNATIVES**

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**TYPES OF REGULATION***Rate-of-Return Regulation*

A full survey of this area is beyond the scope of this work, so a brief summary is instead presented. Small (1999) presents a taxonomy, beginning with the traditional “rate of return” or “cost of service” regulation most commonly applied to integrated utilities in the US throughout most of the twentieth century. Under this approach a monopolist is permitted to earn only a “fair” rate of return on its assets – particularly relevant where the monopolist is privately owned, but also finding application to state-owned monopolies – which reflects not just the prices it charges on its outputs but also its costs of production, over both of which the monopolist retains discretion. A natural criticism of this approach is that the monopolist can be assured of returns on assets that are uneconomic (indeed, can result in “gold-plating” or ill-considered investments), paid for by consumers (who ultimately bear the financial risks of investment and supply), and faces little incentive to reduce costs (a formula for managerial slackness). This is clearly untenable when there are no barriers to entry, since competing suppliers could then undercut the regulated party. Where such natural or artificial barriers exist, however, the monopolist is constrained by (aside from rate-of-return regulation) only consumer or government pressure, where costs are revealed to be excessive, and the ability of consumers to reduce their demand if prices are too high (which ability, by presumption, is limited). The rate-of-return approach has been praised as involving close cooperation between the regulator and the monopolist, given the information requirements it entails for measuring and monitoring asset base and returns, but also criticised for the risk of “regulatory capture” of the rate-setting process by a monopolist typically better-resourced than other interest groups to influence regulator decisions.

*Incentive Regulation*

The weaknesses of the rate-of-return approach have resulted in a major shift in approach over the past two decades. So-called “incentive regulation” has become the regulatory method of choice since its introduction in 1980s privatisations in the United Kingdom. While “first-best” regulatory approaches seeking to induce a monopolist to act in a more socially desirable manner have been attractive in principle (although subject to distortionary costs of their own), their chief limitation arose from the informational asymmetry between regulator and monopolist. It is hard enough for a firm to accurately estimate its own costs of production, let alone for a regulator (reliant on the monopolist for accurate and unbiased revelation of its costs) to do so. Incentive regulation tries to mitigate such difficulties by allowing the regulated firm to make its own pricing decisions subject to certain overall constraints (such as price or revenue

growth sometimes based on assumptions as to future demand growth, production costs and investments) – which leave it with considerable scope to increase profitability by reducing costs. Vogelsang (2002) points out that, by so doing, the regulator reduces its vulnerability to informational asymmetries and instead relies on the firm's superior knowledge of its costs and desire for profit, and shifts attention away from behaviour to outcomes.

Incentive regulation schemes typically take the form of imposed caps on price or revenue growth, known as RPI-X (United Kingdom) or CPI-X (elsewhere). RPI or CPI refers to the movement in some general price index and X represents a measure of required efficiency gain. Thus if X is 2%, for example, then prices or revenues of the monopolist will be permitted to grow at a rate that is 2% less than general price inflation for some specified period, or in other words fall in real terms by 2%.<sup>62</sup> While there is some theoretical basis for determining an appropriate value of X, it is decidedly thin; and in reality X is either set by negotiation (such as during the British privatisations), or on the basis of simple empirics, or according to some hypothetical model of what costs ought to be (echoing the engineering model of old), or arbitrarily (i.e. at the regulator's discretion, subject to pressure from political and other interest groups).<sup>63</sup> Another complication of such an approach is that revenue or price rises permitted under CPI-X regulation become a self-fulfilling prophecy, with regulated firms increasing their revenues or prices by the allowed amount even where they might otherwise not have intended to raise them (at all or by that much).

Implementing incentive regulation requires determining the period over which it is to be implemented, adhering to the scheme and credibly amending it if changes are required, and maintaining quality and investment. For the monopolist to have strong incentives to reduce costs, it is desirable for any price or revenue caps to be set for a relatively long period (commonly five to ten years) before review, with monopolists facing incentives to appear more "costly" the closer they are to a cap review in the hope of this resulting in looser caps.<sup>64</sup> The difficulty is that monopolists might in fact secure significant cost efficiencies or otherwise increased profits in such a period – from their own efforts or simply due to external circumstances – which can prove to be politically intolerable. The consequences of setting an inappropriate value for X become exponentially greater as the review period lengthens. The temptation in such circumstances is for the regulator to prematurely intervene, with potentially significant

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<sup>62</sup> This is only approximately true, since price growth is measured multiplicatively, not additively.

<sup>63</sup> The theory for setting X is presented in Bernstein and Sappington (1999), based mostly on identities and with the key "idea" being that super-profits under competition would over time disappear. Imposing CPI-X in a non-competitive environment is then hoped to replicate outcomes over time more closely reflecting those expected under competition. It is this analysis that underpins the total factor productivity analysis methodology recently applied in setting price caps for New Zealand lines companies and Transpower – see Meyrick and Associates (2003).

<sup>64</sup> Small (1999) suggests this problem might be mitigated by having random cap review periods, but Pint (1992) instead argues for fixed review periods based on average rather than terminal-period costs.

value consequences to the monopolist and corresponding disincentives to make large or long-term investments on which returns are then at risk of expropriation. It must be acknowledged that the risk of long review periods is also to the monopolist, with overly tight caps over long review periods having the potential to cause bankruptcy.

Adhering to the scheme is important to the regulator for its own purposes, if not for the monopolist's shareholders. Any early cap reviews can encourage the monopolist to "call the regulator's bluff" by seeking early reviews, if that suits its interests (e.g. it has been unable to secure cost reductions and sufficiently increased profits because the cap is uncomfortably tight). Alternatively, a regulator's failure to tightly monitor and enforce caps can encourage the monopolist to breach them in the hope the regulator will not take corrective action, leading to windfall profits.<sup>65</sup> A complication arises when circumstances (not foreseen at the time caps are set) give rise to legitimate grounds for review. This is potentially the case currently in the UK, where government policies to encourage investments in renewable generation require grid investments not anticipated when transmission price caps were set some years previously (and these caps are not due for review for years to come).<sup>66</sup> If the relevant caps are reviewed early, there is scope for the regime's credibility to be undermined (not least because there is little science to determining what circumstances were not foreseen or relevant, or even how to properly take them into account), or for the monopolist to extract benefits from an early review that are additional to those strictly relating to the changed circumstances.

### *Approaches Compared*

An obvious point of distinction between rate-of-return and incentive regulation is that the focus is less on required investments and allowable shareholder returns, and more on cost efficiencies and price reductions enjoyed by customers. Indeed, by setting a positive value of X it is intended that consumers benefit from real price reductions while the monopolist retains the incentive and capacity to enjoy increased profits through cost reductions. Furthermore, while rate-of-return regulation can be said to encourage gold-plating and unnecessarily high quality levels, under incentive regulation quality can be compromised in lieu of cost reductions as a means to increase profits, requiring simultaneous contracting for desired quality standards.

Another key contrast between rate-of-return and incentive regulation is that the regulated firm shares investment and supply risks with consumers, instead of consumers shouldering those risks as they do under rate-of-return regulation. A higher

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<sup>65</sup> The Commerce Commission faced its first real credibility test following its move from light-handed regulator to distribution company price-capper. With CPI-X control thresholds for lines companies promulgated in December 2003 – the X for Hawke's Bay operator Unison being set at 0% – Unison in January 2004 announced a price rise of 9% (well ahead of current inflation) and signalled that more rises are required to fund required investments. For its part the Commission has signalled that it will be taking any such breaches seriously. Game on!

<sup>66</sup> See Ofgem (2003b).

rate of return is thus warranted under incentive regulation to recognise this extra risk. Moreover, whereas rate-of-return regulation requires barriers to entry to be effective, incentive regulation is consistent with competitive entry.

As pointed out by Small (1999), it is an oversimplification to suggest that incentive regulation remedies the problem of rate-of-return regulation favouring investors by shifting the risks of inefficiency and poor investments to consumers, and that it is inherently superior as a means of regulation. Much depends on how each method is implemented over time,<sup>67</sup> and under price-cap regulation for short periods the two methods in effect converge.

### *Hybrid Models*

Hybrid forms of regulation are possible, such as thresholds being set for combinations of each method to be applied. While seeking to achieve the best of both worlds, this approach tends to suffer from both of their failings. In certain circumstances it is possible to shift attention from regulating the monopolist, and instead to seek to capture the benefits of competition by selling the right to be the monopolist. Such “franchise bidding” has been applied in various countries to “build-own-operate” and “build-own-operate-transfer” schemes for discrete roading and other infrastructure investments, under which the monopoly rights to a project for a specified period are tendered. The expectation of such schemes is that competitive bidding for the monopoly rights will see the value of any monopoly pricing being captured by the state through the bidding process, as a means of redistributing the welfare losses arising from monopoly operation.

New Zealand’s light-handed approach of the 1990s can be viewed as incentive regulation where the review period is arbitrarily long and dependent upon general assessment of the performance of the industry. Viewed this way, it can be expected that productivity growth and quality provision can be expected to be at least that of more explicit RPI-X incentive regulation – which most deem to perform better than the vanilla rate-of-return regulation.

## COMMON REGULATORY PROBLEMS

### *Cross-Subsidy*

Irrespective of the choice of rate-of-return regulation (whether based on an historical-cost or a replacement (ODV) rate base) or incentive regulation, or indeed other forms of regulation, some issues are common. First is that of pricing multiple product or service areas where considerable scope can remain for the monopolist to raise prices in

<sup>67</sup> Indeed, Evans and Guthrie (2003) show that policies directed towards encouraging competition while subjecting incumbent firms to incentive regulation increases their risk of asset stranding – a problem not arising under rate-of-return regulation – and therefore requires a higher regulatory rate of return.

product areas (for example, where market power is enjoyed) in order to subsidise other product areas that are vulnerable to competition. Alternatively, where common costs require allocation across various product areas of customer classes, the monopolist has discretion to determine allocations any number of ways, some of which are more efficient than others. Both rate-of-return and incentive regulation can in fact be applied at the individual product or service level, but the informational requirements of this are high, reintroducing problems of informational asymmetry and regulatory capture that are otherwise mitigated, at least in principle, by incentive regulation. Additionally this approach effectively also shifts an important aspect of the monopolist's business decision-making to the regulator, in effect nationalising its operations to some extent while leaving the risks of the regulator's decisions with the monopolist's owners. Similar issues arise in respect of investment decisions, discussed further in Chapter 10.

### *Service Obligations*

Another shared issue confronting regulators in the reformed electricity industry context is that of service obligations. Historically monopoly and/or vertically integrated firms in the electricity industry have carried service obligations – such as the obligation to supply energy to any customer in a franchise area – as a *quid pro quo* for avoiding break-up. Regulating a firm with a requirement to supply has quite different implications from regulating a firm with discretion to invest: in general, discretion to invest means that regulation has to be doubly careful that investment is not impaired. In a reformed electricity sector it is typically no longer possible to impose a requirement for supply security, as no one competing generator – or even transmission where it no longer controls generation – is capable of assuming that obligation.<sup>68</sup> As argued by Crew and Kleindorfer (2002), imposing service obligations on incumbent utilities in a reforming electricity sector that seeks the entry of new competitors which need not share that burden, or do so unequally, remains one of the greatest ongoing challenges to reformed sectors. An alternative view, explored in Chapter 10, is that expectations of service obligations in a deregulated electricity sector are misplaced, as market participants ought to determine the level of supply security they are willing to pay for.

### *Degeneration to de facto Government Control*

Neither regulatory approach addresses fundamental issues of industry structure or offers a road-map for determining optimal investments (although each will affect investment incentives). These remain issues of broader institutional arrangements and regulation that take their influences from high-level policy goals of encouraging competition, market-based solutions and private-sector involvement. To the extent that they do not, but instead reflect a return to the highly centralised “command and

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<sup>68</sup> Alternatives include charging the system operator or some other body to contract for reserve generation and/or interruptible load over and above that required for short-term grid security (i.e. ancillary services) – for example, funded by a levy on electricity prices. As discussed in Chapter 6, New Zealand's new Electricity Commission has been charged with this responsibility.



control” approach more typical before worldwide electricity reforms began, they risk regulation collapsing to a *de facto* form of government control, albeit with greater and more mobile (in the sense that their investment can stop and they can be sold) private-sector interests at stake.

### *Redefining the “Game”*

Finally, as referred to earlier, regulation does not eliminate gaming or market power, or even necessarily diminish the welfare costs they can bring. Instead it transforms the issues from one arena to another, and/or transforms their form. Gaming a regulator – such as playing regulatory “chicken” or “stares” – can be just as (or even more) productive as gaming voluntary market rules.<sup>69</sup> Also, politicians and regulators are potentially more susceptible to capture by powerful industry interests than market-rule-making processes, because there is greater scope for them to be influenced behind closed doors (and because their objectives and own interests are likely to be more diffuse). A perpetual shortcoming of regulation remains that it can too easily degenerate into controlling undesirable behaviour instead of predisposing industry participants to strive towards desirable ends – a combination of stick and muzzle instead of carrot and stick. And to end on a different metaphor, regulation is a sword that has two sharp edges.

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<sup>69</sup> Soccer players, for example, game the regulator any time they milk a penalty from the referee.



*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.

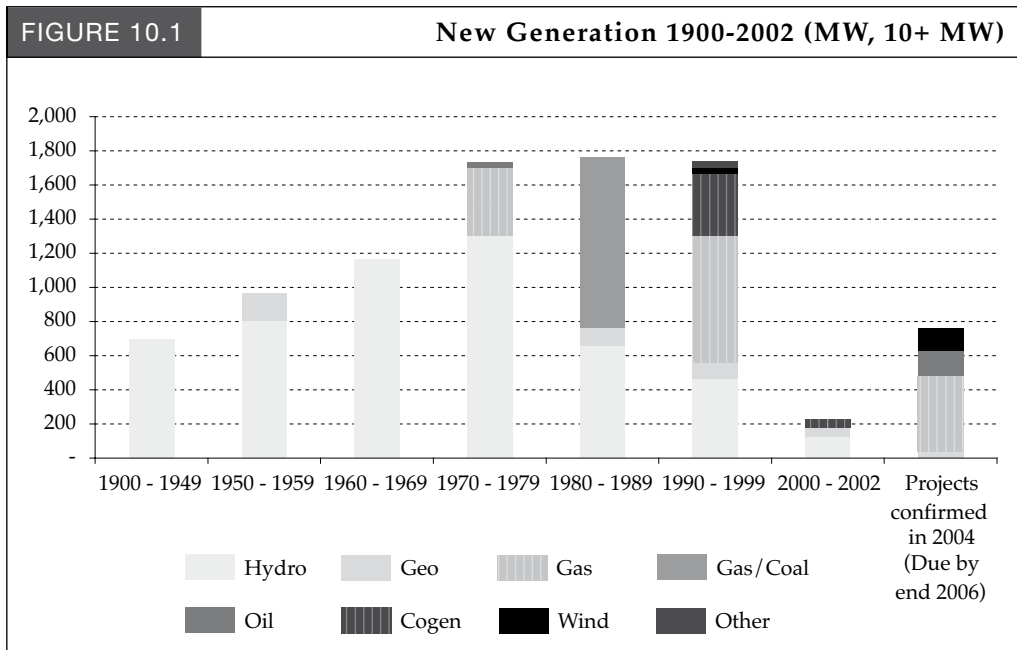
Central government is often regarded as the leading contender, but this too begs the question as to whether central government should determine the required solutions, or instead create a framework within which solutions can be determined by those

<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-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.



## CENTRALISED BUT PRIVATE ORIGINS

Electricity systems in many developed countries started as private enterprise. In some this was short-lived, and state ownership predominated for some or all of the twentieth century. For most of that century vertically integrated monopoly provision was the rule, either by private operators subject to regulation or by state operators subject to less structured political regulation. In part this shift was motivated by the physics of integrated electricity networks – the requirements of technical coordination in growing and increasingly integrated national networks – but it was also a reflection of political economy.

## DECENTRALISATION AND PRIVATISATION HIGHLIGHTING GOVERNANCE

Developments in technology and economics have reduced the importance of unitary control (state or otherwise) of electricity systems. They have enabled imperfect competition to be introduced into generation and retailing, against a backdrop of monopoly, for the benefit of consumers of all sizes. Poor performance of centralised systems, and changing political imperatives have also spurred change in how electricity systems are viewed and run. Modern economies demand ever more of electricity, in terms of both quality and quantity. These factors, and fiscal constraints, which are one motivation for privatisation, tilt away from centralised control to more decentralised solutions. Increased resource competition, including from environmental interests and, in respect of water resources, from farmers and recreational users, have all played a role.

As suggested in Chapter 1, a consequence of these changes is that “power” increasingly relates not only to the technology of electricity, but also to its governance and wider political economy. Questions of competing resource use, the evaluation of increasingly scarce resources (water, clean air, grid capacity), industry evolution, and governance of industry institutions all now come to the fore. To a greater extent than before, those bearing the costs of decisions affecting the electricity sector have enjoyed the possibility of involving themselves in the solutions.

To a large extent the trend in reforming countries has been towards “facilitated” industry development. By virtue of direct government ownership or heavy regulatory interest at the start of the reform process, reform requires relinquishment of some measure of control by centralised states/regulators in favour of decentralised, industry-led control. The process is therefore necessarily “top-down” rather than “bottom-up” in its thrust. Some authorities have found it harder to “let go” than others, and where reforms have been poorly implemented (such as in California) it is natural, if not necessarily

helpful, that heavy re-intervention has resulted. In England and Wales, by contrast, re-intervention resulted in a radical change in direction under NETA, with a notable dichotomy resulting – that between privatised operations with highly decentralised markets, and ongoing state control. In most countries, the continuing drift is to regulatory structures that facilitate decentralised operation of electricity markets.<sup>1</sup>

## NEW ZEALAND RE-CENTRALISING WITH ONGOING STATE OWNERSHIP

In New Zealand, the recent shift has been towards a combination of continuing state-dominated ownership of generation, retailing and transmission, modified yet mostly still-local ownership of distribution, new heavy-handed regulation of transmission and distribution, and a resumption – or indeed assumption – of centralised government control after a period of industry-led self-governance. This move has been characterised as necessary given the experience of the 2001 winter crisis, but the history of winter crises in New Zealand shows that the reformed electricity sector has clearly bettered its predecessor in this regard. Supply security is apparently now the industry's greatest challenge – one which it supposedly has not met – but lack of security was enjoyed before the reforms, and recent moves will not ensure it either.

## SUPPLY SECURITY A FOCUS

In part New Zealand's reversion to centralised industry control may be based on a misunderstanding – it is questionable whether, as a goal, supply security makes any sense in the context of a properly functioning market-based electricity system. Alternatively, this reversion may reflect an unwillingness on the part of some to accept the new environment. The misunderstanding is that all electricity users demand a given level of supply security, and are willing to pay the same level of “insurance premium” to achieve it. It is natural, based on such a misunderstanding, to be apprehensive at a reformed electricity sector's lack of obligation or centralised coordination to ensure “the lights stay on”. It is also misplaced. In the reformed environment it is up to electricity users and suppliers to seek out arrangements for their own supply security, if that is more economic than investing in interruptible load, self-generation, process flexibility and/or energy efficiency. This carries costs. Before the reforms of the early 1990s all parties lacked the clear price signals (whether real-time pricing, or fixed prices incorporating “insurance premiums”) they needed to make these costs bearable. It is natural that they should not wish to face these signals, as that implies other electricity users are paying the necessary costs for them. Without all decision-makers bearing price signals, decisions about the socially desirable use and production of energy will not occur.

<sup>1</sup> See Burr (2004), for example, on progress in developing the huge US midwest electricity market.

## DECENTRALISATION PROVIDES OPTIONS

There is a flipside of reform that some might struggle to accept. Decentralised reforms provide consumers with options – from whom to buy their electricity, in what form (i.e. risk and term characteristics), and at what cost? But they also require electricity users to make choices, and to seek out and even create solutions that might not even have been possible before. Electricity is no longer something that just comes out of the wall at a regulated price. There is now a menu of possibilities from a range of sources, either on offer or achievable. Electricity users must now consider which option is best for them, and engage with suppliers to secure new options where they are not already available. Markets do not consist simply of supply, or of demand, but the dynamic and active engagement of the two. This engagement encourages the active pursuit of solutions to energy efficiency that flow through to the use of resources so important to the economy and environment.

For individual smaller users the cost and expense of active search, investment and management of electricity *per se* is typically not worth the trouble (even if other moves, such as insulation, are more likely to be worthwhile). Most households, on average, spend less on electricity each week than they do on takeaway meals. The savings achievable from consumer search are small. As such, most are likely to be happy for simple certainty on price, quality and supply. Through the vertical integration of generation and retailing, each is typically enjoyed. Even during the 2001 winter supply crises and 2003 winter scare, smaller users were oblivious to the dramatic increases in wholesale electricity prices required to ensure demand stayed in balance with genuinely scarce, weather-affected supply. If they had not been, they instead might have engaged in the usage reductions necessary for larger users who had greater exposure to wholesale prices. It is no surprise that voluntary power savings – a relatively costless solution – were required. Since some retailers also offered rebates for small customers to reduce consumption during the crises, such voluntary savings were only part of the solution. In any case, blackouts were averted in the midst of scarce supply – a vast improvement on the pre-reform experience.

## DEMAND-SIDE RESPONSIVENESS – HELPFUL, BUT DESIRED?

Securing a demand-side response from smaller consumers remains a challenge. Given the measured insignificance of electricity costs to individual households, most have little incentive to invest in costly energy efficiencies or to conserve. The same can be said when wholesale prices temporarily surge, given that most households do not face immediately increased power bills as a consequence. The size of such occasional surges, however, carries the potential for a very real small-customer demand-side response – if technology would allow it. Since wholesale prices peak at many times their normal level, this implies a latent source of profit that even small

households might seek to exploit if only they could. With improvements in metering and communications technology it should be expected that smaller customers will one day be able to exploit profitable opportunities to sell surplus energy, through power exchanges, to other customers more desperately in need of supply when wholesale prices surge. This should unlock significant new capacity in future supply shortages, and simultaneously reduce the size of price spikes and any incentives for the exploitation of generator market power. Although there are potential household benefits in alternative supplies – e.g. solar heating – a power exchange would provide an additional incentive.

For larger users the options available in the reformed electricity sector, and the incentives to seek them out, are greater than for smaller customers. Large industrial customers have traditionally enjoyed lower electricity prices than other users, and this has remained under the reforms: indeed, the relatively higher prices paid by households will in part reflect their insulation against short-run price fluctuations. In the face of challenges to supply security, larger users now bear an increased level of price risk, particularly when supply is scarce, which is to be expected since they also comprise the lion's share of demand. Before the reforms all users absorbed this risk through greater exposure to blackouts. Now larger users bear it in the form of potentially large increases in short-term prices. This has spurred them to more carefully manage their electricity usage and to contract for their preferred supply- and price-risk profile. It has also provided them with opportunities to profit (when the value of their output is not as great as the returns they enjoy) by selling surplus power under fixed-price contracts to other users for whom spiking wholesale prices are not high enough to curtail demand.

## GAMING INCENTIVES

Larger users also face other options and incentives, however. In making the investments required to better manage energy usage, and supply and price risk, they must balance the associated costs with the available alternatives. The most obvious is to “game” the reformed electricity sector, by lobbying for favourable changes to industry structure and rules. The more that industry control is centralised – and the fewer, more organised and resourced the larger players – the lower the transaction costs of doing so. The more such control is centralised in the hands of regulators and ministers with discretions, rather than market rules and independent surveillance, the more the regulators and ministers become the target of such gaming, and the less clear and transparent the gaming becomes. Such a shift can also attenuate their ability to secure change, with competing interest groups also able to exploit such channels. Consumers or users outside the circle of effective interest groups, however, may bear more than their fair share of any resulting changes. Such an interpretation can be attached to the reintroduction of centralised industry governance, and to imposition of an energy tax on all consumers to fund the reserve generation scheme.



The supply side of the electricity industry can also engage in such gaming – some might say “more so”, because of its information advantages and centrality in meeting current and future supply. But it also has other instruments at its disposal to reduce its exposure to gaming by others. Finding ways to lower the transaction costs of meeting user needs is an obvious analogue to the more basic imperative for generators to supply at competitive prices. Small users can also organise to game the system, but once again the transaction costs of their doing so can limit their effectiveness and resulting benefits.

## RESPONSES TO GAMING AND MARKET POWER

Gaming and market power, more generally, will arise in any electricity system, reformed or otherwise. State ownership and/or control have traditionally been blunt instruments for limiting their undesirable effects. Advances in regulatory approaches, technology and the economics of electricity market design have allowed for more refined solutions. The use of incentive regulation combined with otherwise highly decentralised markets in NETA have largely eliminated the twin evils of gaming and market power, while at the same time allowing for consumer gains, greater demand-side participation (through power exchanges), and taxpayer enjoyment of the returns and decreased risk exposure achievable without state ownership. The same general findings apply to various extents to PJM, and other electricity markets.

New Zealand is instead opting for highly centralised responses to those issues. State ownership remains for most of generation and retailing, and for all of transmission. However inefficiently, any excess returns derived by generator market power (if and when it arises and is exercised) accrue largely to government. Similarly, any excess profits earned by transmission so accrue, but transmission pricing is regulated and the company is enjoined to seek efficiency rather than the standard business objective of profit. To price-cap transmission in such a state is of questionable merit (especially given regulatory costs), has unpredictable effects, and confounds accountabilities. Similarly, to price-cap distribution companies owned by cooperatives and consumer trusts is excessive, given their different objectives and the hedge such ownership provides against monopoly abuses. The purpose of such regulation is unspecified and, particularly with multiple agencies regulating prices, the outcome for consumers is highly problematic. Significantly, New Zealand's transition to heavy-handed regulation has not been accompanied by an allocation of function and responsibilities that enable principles of standard regulatory mechanisms to be effected. It is curious that the matter of monopolies in electricity distribution receives such regulatory attention given that there are unregulated local-body monopolies in water and sewerage provision in most parts of the country.

## PRESERVING INVESTMENT INCENTIVES

Certainly it will be important to ensure that New Zealand's recent shift from light- to heavy-handed regulation does not stifle desirable investment. This is more an issue for non-central-government-owned distribution than for state-owned transmission, as the latter is now subject to the direction of the new Electricity Commission on its fundamental pricing and investment policies and therefore has little initiative to be stifled. Because of the interactive functions of the relevant players and the objective of the company, the outcome for transmission will be difficult to predict. New investment in distribution is required to accommodate demand expansion, and also innovative demand and supply management. It will be affected by restrictive regulation that has the potential to undermine the necessary returns,<sup>2</sup> with the result that either such investments do not arise in a timely fashion or they do so on uneconomic terms.

But regulatory risks are not the only obstacles to investment. The demise of Project Aqua has illustrated the problems of cost, delay and uncertainty surrounding the processes necessary to securing property rights required for long-term, large-scale generation investments. The unexpectedly fast run-down of Maui gas reserves has increased the urgency of finding alternative gas and other energy sources. The RMA process, the risks of that process being modified on an *ad hoc* basis, and the fundamental lack of certain, tradable water rights cannot enhance the prospects for hydro generation investments. So too does uncertainty surround Kyoto policy generally, and emissions-rights implementation and trading – all of these affect thermal generation (both gas and coal). It is curious that issues around environmental protection should be hindering large-scale hydro projects in favour of coal, although efficient coal-based generation would offer significant advantages over hydro in terms of supply security (given large domestic coal-reserves). Smaller-scale renewable generation projects such as wind power are at present limited solutions that carry their own costs and complexities (including environmental hurdles).

It is reassuring, if not surprising, that new generation investment has continued post-reform despite many of these uncertainties. Major surges in wholesale electricity prices during the winters of 2001 and 2003, when hydro reserves were scarce, certainly provided clear signals of the returns available to investors in new capacity. That the wholesale electricity price also falls to almost zero when hydro reserves are high further illustrates that the market is providing a clear indication of the shadow price of water – a price that is relevant in all its uses. It also belies suggestions that the wholesale price is dominated by market power, a conclusion supported by the fact that average prices have been below the predicted long-run marginal costs of new generation. It remains to be seen the extent to which the *de facto* price cap operative under the new Electricity Commission's reserve generation measures will constrain any required new investment.

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<sup>2</sup> An issue more or less present in all price-cap regulatory schemes.

## ELECTRICITY COMMISSION CHANGES INDUSTRY FOCUS

Aside from the reserve generation trigger price, the Electricity Commission is now well involved in the markets for electricity in New Zealand (a significant responsibility given the importance of electricity prices in determining the industry's future course). Governance and even operation of the industry's three main institutions – the NZEM, MARIA and MACQS – has now been merged under the Commission's purview. Wide regulatory powers were granted to it under its initial legislation; these were widened substantially in 2004. New Zealand was possibly unusual in the extent to which its major electricity-sector institutions were created voluntarily by industry with so little government control or input. In part, the NZEM's development could be described as a reaction against the 1991 pricing show-down between government and ECNZ when the extent of new industry freedoms was being tested. Perhaps the latest moves to centralise industry control in government hands is a corresponding counter-reaction, with the government unmistakably taking a firm hold of industry's "rattle". Certainly it represents a trend contrary to reforms in other countries: even in England and Wales, where strong regulatory intervention was the norm in the reformed industry, early failures led to greater market decentralisation rather than increased government control. A natural consequence of these moves is that any future industry failures, perceived or real, will increasingly be attributed to government and less to industry.

The major test now confronting the Commission is whether it will create an ongoing industry framework that fosters consumer-benefiting competition and encourages efficient investment. Each is crucially affected by choices regarding the nature and extent of now-due upgrades to New Zealand's transmission grid, since Transpower's all-important pricing and investment policies have become the responsibility of the Commission. If it opts for traditional, centralised and administrative approaches to grid expansions – based more on issues of technical security than competitive topology and economic welfare – then the benefits of future evolution of the sector should be expected to be constrained. If instead it opts for more decentralised solutions, by relying on market-derived evaluations of the costs of grid congestion and creating incentives for those bearing those costs to see them relieved, then superior outcomes should be the result. In any case, the problems of grid investment are arguably better resolved by improving the ownership structure of transmission – an initiative not currently under consideration, but mooted early in the reforms.

## NEW ZEALAND'S REFORMS SUCCESSFUL TO A POINT

New Zealand's electricity-sector reforms, like those in other jurisdictions, have had their successes. Importantly, they have not involved outright failures such as those in California. Certainly major distortions in previous arrangements, such as significant cross-subsidies from small commercial to residential customers, have now been

removed, creating a possible perception that the electorally powerful residential customers have suffered. But the taxpayer subsidies for generation (overcapacity), which arguably favoured larger users, have also been removed. Real price declines have been the norm in energy, transmission and distribution prices since the reforms began, without regulatory intervention: these are not the signs of reform failure. At the same time, more customer-focused options are now available to users – as they were not, before the reforms. As owners of state-owned generators and transmission, New Zealand taxpayers have enjoyed significant increases in tax and dividend payments that were not transparently available before the reforms. Taxpayers have also not had to reach into the public purse to fund new investments (or induced costly and environmentally insensitive investment as in the past). Potentially these benefits would have been greater, and the risks to SOE value from future industry changes less, had (even partial) privatisation been more widespread. Certainly, the sale of Contact Energy to private owners has not been to the detriment of electricity users or taxpayers. It is doubtful that industry arrangements existing before the reforms would have delivered the gains enjoyed.

#### MORE RECENT REFORMS CAST A SHADOW

It remains to be seen whether New Zealand's present isolated trend towards greater centralisation of industry control under government – given predominant state ownership – will persist, at least to the extent currently prescribed. In this sense it may prove to be a temporary oscillation in the context of a more consistent overall trend to decentralised electricity supply and demand decisions. It should be hoped that the broad thrust of the reforms will be preserved, not just to secure successes achieved but also because industry failings are vastly more transparent under recent arrangements than they were under their predecessors, and are therefore more amenable to timely and efficient correction. The danger would be to overreact to any perceived or real industry failings and so deepen the reversal of sound industry arrangements.

Over-anxious measures by government to elicit desired responses from industry may have the very opposite effect, causing private-industry players to react cautiously. This could leave only government able and ready to fill any gaps resulting from such a reaction. It raises the prospect of government crowding out or otherwise distorting private-industry initiatives, and finding itself solely responsible for industry's progress (and failures). Certainty over the industry's future overall course, including the bounds on government involvement, will be just as important to decentralised industry initiatives as beneficial policy choices along the way. Without such certainty, or given poor policy choices, the dangers of returning to the pre-reform model – of potentially counter-productive "de-reform", intended or otherwise – are increased.

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**1 THE POWER GAME**

<b>Introduction</b>	19
<i>The Importance of Electricity</i>	19
<i>Historical Supply Approaches</i>	19
<i>Winds of Change</i>	20
<i>Purpose of this Book</i>	20
<i>Analytical Criteria</i>	21
<b>Lead Actors in a Model Electricity System</b>	21
<b>“Power” in the Electricity Sector</b>	22
<i>More than just Physics</i>	22
<i>Role of Technology</i>	22
<i>Some Other Types of Power</i>	24
<i>Importance of the Ability to Set Electricity Prices</i>	24
<i>Influence of Electricity Prices on Consumer Conservation and Efficiencies</i>	25
<i>Shifting Power amongst State Sector Electricity Actors</i>	26
<i>Control of the Wholesale Electricity Market</i>	26
<i>Consumer Choice</i>	26
<i>Market Power in Transmission and Distribution</i>	27
<i>Industry Governance and Development</i>	27
<b>A Look Ahead</b>	28

**2 ELECTRICITY AND ELECTRICITY MARKETS**

<b>Introduction</b>	31
<b>What is so Special about Electricity?</b>	31
<i>In General</i>	31
<i>In New Zealand</i>	34
<i>Price-Inelastic Electricity Demand</i>	35
<i>Short Run versus Long Run</i>	37
<i>Decreasing Price Elasticity of Electricity Supply</i>	38
<i>Centralised Electricity Markets</i>	38
<i>Decentralised Electricity Markets</i>	40
<i>Comparing Electricity Market Types</i>	41
<b>Electricity Markets – How They Work</b>	42
<i>Engineering Meets Economics</i>	42
<i>Electricity Market Architecture</i>	42

<i>System Operator and Ancillary Services</i>	42
<i>Wholesale Markets, Market Operation, Scheduling, Dispatch, and Balancing</i>	43
<i>Wholesale Market Types</i>	43
<i>Hedging</i>	44
<i>Zonal versus Nodal Pricing – Losses and Congestion</i>	44
<i>Linkages to Other Markets</i>	45
<i>Comparing the NZEM with Other Electricity Markets</i>	49
<b>Electricity Markets – Do They Work?</b>	50
<b>Conclusion</b>	54
APPENDIX 2.1 – A BRIEF TAXONOMY OF MARKET TYPES	56
<b>Introduction</b>	56
<b>Bilateral Markets</b>	56
<b>Mediated Markets</b>	57
<b>Exchange or Auction Markets</b>	57
<b>Electricity Pools</b>	58
APPENDIX 2.2 – DECENTRALISED DECISION-MAKING AND THE NZEM	59
<b>Information and Accountability</b>	59
<b>Coordination under Decentralisation</b>	59
<b>Rationale for Decentralisation versus Centralised Control</b>	61

### 3 THE NEW ZEALAND ELECTRICITY SYSTEM

<b>Introduction</b>	63
<b>National Energy Sources and Uses</b>	63
<b>Structure of the Contemporary Electricity Sector</b>	66
<b>Generation</b>	67
<i>Reconfiguration and Ownership</i>	67
<i>Location</i>	68
<i>Composition</i>	69
<b>Spot Wholesale Electricity Market</b>	72
<i>Structure</i>	72
<i>Services and Operation</i>	73
<i>Pricing and Performance</i>	74
<b>Transmission</b>	77

<b>Distribution</b>	85
<i>Composition and Ownership</i>	85
<i>Financial Performance</i>	86
<i>Operational Characteristics and Performance</i>	89
<i>Lines Quality</i>	91
<b>Energy Retailing</b>	93
<b>Consumption</b>	96
<b>Financial Returns</b>	99
<i>Returns to Government and the Taxpayer</i>	99
<i>Financial Performance</i>	101
<b>Conclusion</b>	106
APPENDIX 3.1 – PERFORMANCE OF THE NATIONAL GRID 1990-2003	107
<b>Introduction</b>	107
<b>Energy Transport</b>	108
<b>Reliability and Security</b>	111
<b>Interconnection</b>	112
APPENDIX 3.2 – NOTES AND SOURCES FOR FIGURES 3.34-3.37	114
<b>General Approach</b>	114
<b>Data Sources</b>	115

<b>Introduction</b>	117
<i>Broad Reform Trends</i>	117
<i>Deregulation, Liberalisation or “Reregulation”?</i>	117
<i>Rise of “the Market”</i>	118
<b>Contemporary Electricity Reforms around the World</b>	118
<b>England and Wales</b>	119
<i>Wider Reform Agenda</i>	119
<i>Reform Background</i>	119
<i>Generation and Transmission</i>	120
<i>Distribution/Retailing and Regulation</i>	120
<i>Re-Reform</i>	120
<b>United States</b>	121
<i>Anti-competitive Regulation Origins</i>	121
<i>Dominance of Investor-Owned Utilities</i>	122

<i>Reform Imperatives</i>	122
<i>California</i>	124
<b>Australia</b>	126
<i>Partially Converging State Reforms</i>	126
<i>Reform Background</i>	126
<i>Reform Motivation</i>	126
<i>National Electricity Market (NEM)</i>	127
<i>Reform Progress</i>	127
<i>Victoria</i>	128
<i>Rapid Change</i>	128
<b>European Union</b>	129
<i>Background</i>	129
<i>EU Reform Directive</i>	129
<i>Further Reform</i>	131

## 5 NEW ZEALAND'S ELECTRICITY REFORM HISTORY

<b>Introduction</b>	134
<i>International Context</i>	134
<i>Domestic Context</i>	134
<i>Existing Arrangements Unsatisfactory</i>	134
<b>Historical Backdrop</b>	135
<b>The Reforming 1980s</b>	137
<i>Reforming Government</i>	137
<i>From Government Department to Corporation</i>	137
<i>Early Policy and Reform Objectives</i>	138
<b>Ownership, Structure &amp; Regulation – The 1989 Electricity Task Force</b>	139
<b>Responses to the Task Force Report</b>	139
<i>ECNZ Break-up Examined</i>	139
<i>Separation of Generation and Transmission – Trans Power Establishment Board</i>	141
<i>Wholesale Market Development</i>	142
<b>Wholesale Electricity Market Study (WEMS)</b>	143
<b>Wholesale Electricity Market Development Group (WEMDG)</b>	144
<b>EIC, M-Co, NZEM, MARIA, and the June 1995 Reforms</b>	144
<b>Break-up of Generation</b>	147
<i>Tying ECNZ's Hands</i>	147
<i>June 1995 Memorandum of Understanding</i>	147

<i>ECNZ's Final Separation, and the Birth of Vertically Integrated "Gentailers"</i>	148
<i>Wholesale Market Prices versus ECNZ Predictions</i>	149
<b>Distribution Reform and Re-Reform</b>	150
<i>Anticipatory Reforms</i>	150
<i>Electricity Act 1992 and Energy Companies Act 1992</i>	151
<i>"A Better Deal for Electricity Consumers"</i>	152
<i>Deemed Profiling and Customer Switching</i>	152
<i>Retail Margins and Competition</i>	153
<b>Regulation and Re-Regulation</b>	154
<i>Birth of Light-Handed Regulation</i>	154
<i>ODV Rules</i>	156
<i>June 2000 Electricity Industry Inquiry</i>	157
<i>Shift to Heavy Regulation</i>	157
<b>"A Fair Deal for Electricity Consumers"</b>	157
<b>Current Agendas</b>	158
<i>Rapid Industry Centralisation – The Electricity Commission</i>	158
<i>Distributed Generation Encouraged</i>	161
<i>Rapidly Expanding Regulatory Powers</i>	162
<b>Conclusion</b>	162
<b>APPENDIX 5.1 – WHOLESALE PRICES UNDER STRUCTURAL CHANGE</b>	164

## 6

## COPING WITH CRISES

<b>Electricity Systems Vulnerable to Shocks and Crises</b>	167
<i>Overseas Events</i>	167
<i>Fuel Risks and the Weather</i>	168
<i>Changing Balance of Supply and Demand</i>	168
<i>Systemic Risks</i>	169
<b>New Zealand's Vulnerabilities and Responses – Before Contemporary Reforms</b>	169
<i>Early Twentieth Century</i>	169
<i>1940s and 1950s</i>	169
<i>1960s and 1970s</i>	170
<i>1980s</i>	170
<b>New Zealand's "Crises" and Responses – After Contemporary Reforms</b>	170
<i>Earlier Lessons Forgotten</i>	170
<i>1992 Winter Crisis</i>	171
<i>Sea-Change in Response</i>	172
<i>Role of the Fledgling Wholesale Market</i>	172
<i>2001 Winter Crisis</i>	173

<i>Government Steps in on Behalf of Industry</i>	175
<i>Residential Customers Insulated but NGC Exposed</i>	175
<i>Reformed Arrangements Criticised</i>	176
<i>Reformed Arrangements Rise to Challenge</i>	176
<i>Voluntary Savings Displace Rationing</i>	177
<i>2003 Winter Power Scare</i>	178
<i>Wholesale Market gives Early Warning</i>	178
<i>Government Intervenes Despite Disappearing Crisis</i>	179
<i>1998 Auckland CBD Outage</i>	180
<i>2004 Loss of the HVDC Link</i>	180
<i>Reformed Arrangements Survive Major Challenge</i>	181
<b>Discussion – Wholesale Electricity Price Rises: Cure or Disease?</b>	181
<i>Lack of Customer Choice?</i>	182
<i>Larger Customers Bear Disproportionate Burden?</i>	183
<i>Inadequate Capacity?</i>	183
<b>Reserve Generation Reconsidered</b>	184
<b>Conclusion</b>	186

## 7 DEMAND-SIDE PARTICIPATION

<b>Introduction</b>	187
<i>An Increasing Focus</i>	187
<i>Economic Issues</i>	188
<i>Main Demand-Side Thrusts</i>	188
<b>History of Demand-Side Participation</b>	189
<i>Pre-Reforms</i>	189
<i>Industry Initiatives Post-Reform</i>	190
<i>Supply-Side Structural Stalemate or Equilibrium?</i>	191
<i>Hedge Market Regulation – Demand-Side Distortions</i>	192
<i>Co-Investments in Demand-Side Initiatives</i>	193
<i>Orion Energy – Decoupling Peak Demand from Demand Growth</i>	193
<i>Metering Advances</i>	194
<i>Power Exchanges</i>	195
<i>Former NZEM Initiatives</i>	195
<i>Electricity Commission Takes Over</i>	196
<b>Energy Efficiency and Conservation Authority (EECA)</b>	196
<i>Some Obstacles</i>	197
<i>Fonterra and NZAS Initiatives</i>	199
<i>Firm and Day-Ahead Prices</i>	199

<b>Whom to Target?</b>	200
<i>A Stocktake</i>	203
<b>The Ultimate Goal?</b>	203
<b>Conclusion</b>	205

<b>Introduction</b>	207
<b>Centralisation and Decentralisation in the New Zealand Electricity Sector</b>	208
<i>Recent International Context</i>	208
<i>Early Decentralisation Short Lived</i>	209
<i>Market Solutions Supplanted by Government</i>	209
<i>Origins of the Wholesale Electricity Market</i>	214
<i>An Unintended Consequence?</i>	215
<b>The Role of Governance</b>	216
<i>What is Governance?</i>	216
<i>When Governance is Relevant</i>	216
<i>Governance and Competition Laws</i>	217
<i>Early Governance in the Reformed Electricity Sector</i>	217
<i>New Electricity Commission</i>	218
<i>Governance Role Expanded to Management</i>	219
<i>Minister Has Effective Control</i>	219
<i>Price Controls Also Imposed</i>	221
<i>Conflicting Roles</i>	222
<i>Electricity and Gas Industries Bill 2003</i>	222
<i>Goal Posts Shifted</i>	223
<b>Transmission Insecurity – What’s at Fault?</b>	225
<b>Conclusion</b>	230
<b>APPENDIX 8.1 – INDUSTRY EVOLUTION, MARKETS, POLITICS, AND DE/CENTRALISATION</b>	232
<b>Introduction</b>	232
<b>Influences Affecting Industry Evolution</b>	232
<b>Industries, Markets and Politics</b>	233
<b>Decentralised and Centralised Control</b>	235

<b>Introduction</b>	239
<b>Gaming</b>	239
<i>Pernicious Overtones</i>	240
<i>Lessons from England and Wales</i>	241
<i>Problems with Uniform Price Auctions</i>	241
<i>Calls for Pay-as-Bid Auctions</i>	243
<i>Changing Issues</i>	244
<i>Gaming of a Higher Order</i>	245
<b>Market Power</b>	245
<i>Horizontal and Vertical Variants</i>	245
<i>Market Power in Generation</i>	246
<i>Market Arrangements to Mitigate Market Power</i>	247
<i>Vertical Integration and Hedging</i>	247
<i>Spot Market "Thinness"</i>	248
<i>Forced Hedging and De-Integration</i>	248
<i>Importance of Transmission Constraints</i>	249
<i>Is Market Power all Bad? – Static versus Dynamic Efficiency</i>	251
<i>Market Power in Transmission</i>	252
<i>Incentives for Efficient Grid Investment</i>	253
<i>Market Power in Distribution</i>	256
<i>Market Power in Retailing?</i>	256
<i>Testing for Market Power</i>	257
<b>Regulation</b>	261
<i>Nature and Motivation</i>	261
<i>Purpose</i>	262
<i>Some Theories of Regulation</i>	263
<i>Regulatory Approaches</i>	264
<b>Ownership Reform – The Neglected Regulatory Component?</b>	265
<i>State Ownership as a Defence against Market Power</i>	265
<i>Profit Motive Aids Regulation</i>	265
<i>Ownership Reforms to Date</i>	266
<i>Community or Consumer Ownership of Distribution</i>	267
<i>Ownership of Transpower can be Bettered</i>	268
<i>US Models of Grid Ownership</i>	268
<i>England and Wales Model of Grid Ownership</i>	269
<i>Other Grid Ownership Models</i>	270
<i>"Club" Ownership of Transpower Shelved Despite Promise</i>	270
<i>Models Compared</i>	271



<b>Some Reflections on the New Zealand Electricity Reforms</b>	271
<i>Market Power and Gaming neither Universal nor Damning</i>	271
<i>Privatisation Feasible but Unpalatable</i>	272
<i>Transmission Issues Remain</i>	272
<i>Limitations of ODV Regulation</i>	273
<i>Over-Regulation of Distribution</i>	274
<i>Distribution Regulation in Context</i>	274
<b>APPENDIX 9.1 – COMPARING REGULATORY ALTERNATIVES</b>	276
<b>Types of Regulation</b>	276
<i>Rate-of-Return Regulation</i>	276
<i>Incentive Regulation</i>	276
<i>Approaches Compared</i>	278
<i>Hybrid Models</i>	279
<b>Common Regulatory Problems</b>	279
<i>Cross-Subsidy</i>	279
<i>Service Obligations</i>	280
<i>Degeneration to de facto Government Control</i>	280
<i>Redefining the “Game”</i>	281

<b>Introduction</b>	283
<i>An Important Crossroad</i>	283
<i>The Grid is the Nub</i>	284
<b>What New Investment Is Actually “Needed”?</b>	285
<b>Issues Confronting New Generation Investment</b>	286
<i>Gas Supply</i>	288
<i>Kyoto Policy</i>	289
<i>Project Aqua and Competition for Water Rights</i>	290
<i>Other Investment Issues</i>	291
<b>Supply Security in Electricity Markets</b>	292
<i>Dry-Winter Episodes Continue</i>	292
<i>Market Reforms Failing to Provide Security?</i>	293
<i>Reserve Generation</i>	294
<i>“Public Goods” and “Market Failure”</i>	294
<i>Capacity Mechanisms and Alternatives Supporting Supply Security</i>	295
<b>Grid Investment</b>	297
<i>Transpower’s Changing Investment Incentives</i>	297

<i>Non-Transpower/Merchant Grid Investment</i>	297
<i>Changing Centralisation of Grid Investment</i>	299
<i>Alternative Strategy to Simplify Grid Investment</i>	299
<i>Contrast with Demand Management and Distributed Generation</i>	301
<i>Using Ownership to Support Grid Investment</i>	301
<i>Customer Ownership to Internalise Investment Incentives and Coordination</i>	302
<i>Regulated Investor Ownership</i>	303
<b>Breaking the Impasse between Grid and Generation Investment</b>	304
<i>The Strategic Problem</i>	304
<i>Regulated Investor Ownership as a Solution</i>	304
<i>The “Club” Model as a Solution</i>	305
<b>Conclusion</b>	305

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<b>11</b>	<b>WHITHER NEW ZEALAND’S REFORMS?</b>
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<b>Centralised but Private Origins</b>	309
<b>Decentralisation and Privatisation Highlighting Governance</b>	309
<b>New Zealand Re-Centralising with Ongoing State Ownership</b>	310
<b>Supply Security a Focus</b>	310
<b>Decentralisation Provides Options</b>	311
<b>Demand-Side Responsiveness – Helpful, but Desired?</b>	311
<b>Gaming Incentives</b>	312
<b>Responses to Gaming and Market Power</b>	313
<b>Preserving Investment Incentives</b>	314
<b>Electricity Commission Changes Industry Focus</b>	315
<b>New Zealand’s Reforms Successful to a Point</b>	315
<b>More Recent Reforms Cast a Shadow</b>	316



# ANALYSING THE INTERPLAY OF TECHNOLOGY, ECONOMICS AND POLITICS...

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Lewis Evans and Richard Meade place New Zealand's current institutional arrangements for its electricity sector within the context of successive waves of economic reform. They compare these arrangements with developments internationally, drawing together lessons for future policymaking both in New Zealand and overseas. *Alternating Currents or Counter-Revolution?* is a work of political economy – and the book carefully analyses the interplay between technology, economics and politics that has at different times driven the sector.

Controversially, the authors argue that the market reforms of the 1980s and 1990s provided greater supply security than the more centralised arrangements prevailing in the past – and that New Zealand's reversion to more centralised and political control since the late 1990s has resulted in an unsustainable half-way house that hinders private electricity investments and reinforces this trend.



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