NZEM
New Zealand Electricity Market

18 December 2002

NZEM Market Participants

Dear Market Participant

## Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM

The New Zealand Electricity Market (NZEM) has employed a full nodal pricing model since it commenced its operation in October 1996. In September 2001, after five years of operation, the Rules Committee considered it appropriate to review the outcomes that nodal pricing has achieved.

It employed the services of an independent consultant to undertake this review. The terms of reference for the review were:

- Review the outcomes that were expected when the decision was made to adopt a full nodal pricing model before the commencement of the market in October 1996.

- Review the actual outcomes produced by the nodal pricing model adopted by NZEM from October 1996 until today. This part of the review should focus more heavily on outcomes achieved since the introduction of daily final pricing, but should not exclude earlier observations.

- Contrast expected and actual outcomes (including transmission risk management options) and provide analysis of whether the expected outcomes were achieved and, if not, provide an outline of what the causes for non-achievement are.

- Make recommendations as to how the nodal pricing model may be improved to achieve the outcomes that were expected when the decision was made to adopt full nodal pricing.

The review focused on empirical evidence rather than re-litigating theoretical arguments. For the purposes of interpreting the above terms of reference, the full nodal pricing model includes the mechanism by which prices are determined for each half hour for each node, as well as the collection of the loss and constraint excess and the subsequent allocation methodology from grid owners through to end recipients.

A copy of the final report from this review is attached for benefit of all Market Participants. The views and conclusions contained in the report are the views and conclusions of the consultant and do not necessarily represent the views of the Rules Committee.

The Rules Committee hopes that this report will provide a useful basis for debate on this aspect of market design. It is noted that significant progress has already been made in addressing two of the issues raised by this report, namely transmission investment and demand-side participation.

On the first of these issues, Market Participants are no doubt already aware of the work of EGEC in developing transmission investment mechanisms in Part F of the proposed new arrangements. These mechanisms are intended to address the issues that have hindered transmission investment to date and contributed to the nodal price separation and volatility highlighted by the report.

With respect to the transmission investment issue, the development of FTR's is relevant. The Government has now released its final Government Policy Statement (GPS) on Electricity Financial Transmission Rights (FTRs). The GPS requires that an industry FTR Group be established to continue development of the FTR product, and that representatives of the Group and Transpower report to the Minister of Energy by 28 February 2003 on an agreed programme and timetable for the establishment of the FTR market. Governance of FTRs will be taken over by the Electricity Governance Board once it is established.

With respect to the second issues raised in the report, attention is also drawn to the significant and ongoing body of work being undertaken by the Market Pricing Working Group of the NZEM in demand-side participation and real time pricing. More accurate price signals and greater opportunities for demand-side participation will aid parties in managing their price risk in real time.

We welcome debate on all and many aspects of market design. Full nodal pricing is a central feature of the NZEM price discovery mechanism. It is hoped that this report is useful as an objective appraisal of the adoption of full nodal pricing and outcomes to date. We welcome debate on these issues and any direct dialogue with the Rules Committee on this matter or any aspect of the report.

Yours sincerely

Toby Stevenson
**Chair NZEM Rules Committee**

Trowbridge Deloitte

# Assessment of Outcomes Achieved by Full Nodal Pricing in the NZEM

**NZEM Rules Committee**

**November 2002**

Deloitte Touche Tohmatsu

11 November 2002

Trowbridge Deloitte

Mr Malcolm Alexander
GM Market Services,
The Marketplace Company Limited
Level 2, Wool House, 10 Brandon Street
PO Box 5422, Wellington,
New Zealand

Dear Malcolm

**Assessment of Outcomes Achieved by Full Nodal Pricing in the NZEM**

Please find attached our final report for your consideration. Please contact us if you have any questions.

Yours sincerely

| | | |
|---|---|---|
| Stephen Weston | Kumar Padisetti | Peter Gough |

Deloitte
Touche
Tohmatsu

# Assessment of Outcomes Achieved by Full Nodal Pricing in the NZEM

B Marginal Losses vs. Average Losses

C Inter-Nodal Price Volatility Statistic

# Part I Summary of Findings

## Introduction

The New Zealand Electricity Market (NZEM) operates a Full Nodal Pricing (FNP) regime whereby the marginal cost of meeting a change in load or generation at each grid injection and exit point ('node') on the country's electricity network is calculated separately for each node. The NZEM adopted the FNP regime in October 1996. At present prices are calculated half-hourly at more than 240 nodes across New Zealand.

## The Brief

Trowbridge Deloitte (Trowbridge) has been engaged by the Rules Committee of the NZEM to assess, on an empirical basis, whether the nodal pricing regime achieved the outcomes expected when the decision was made to adopt it.

For the purposes of our study the Full Nodal Pricing model includes:

- the mechanism by which pool prices are determined;
- the collection of Loss & Constraint Settlement Surpluses (L&CS); and
- the subsequent allocation of L&CS.

Our study extends to an outline of the causes for non-achievement of expected outcomes where the empirical evidence suggests that expected outcomes have not been achieved.

## Consultative Process

We commenced the study by consulting with market participants to determine outcomes expected when the market was established and to identify key concerns with the current market design.

The market participants we consulted with included:

- Grid Owner and System Operator;
- Net Generators;
- Net Retailer;
- Major Energy Users;
- Market Administrator; and
- Lines Company.

The interviewees are listed in Appendix A.

## What Outcomes were Expected?

Based on the information provided to us at the initial meetings, and our subsequent review of relevant documentation, we have grouped the expected market outcomes under five major headings.

The following table summarises the expected market outcomes we have identified:

**Table 1**

| | Expected Outcomes |
|---|---|
| 1. | Efficient Short-Run Operation |
| 2. | Efficient Long-Run Operation |
| 3. | Ability to Manage Risk |
| 4. | Effective Retail Competition |
| 5. | Competitive Price Discovery |

At a meeting held on 2 May 2002 the Rules Committee agreed that these expected outcomes were appropriate criteria against which actual outcomes should be measured. It is important to note that, in most cases, the pricing regime would not be sufficient of itself to achieve the expected outcome. Our report emphasises those aspects of FNP that we believe have contributed to observed market outcomes. In addition we have highlighted features of the New Zealand Electricity Market (NZEM) that act as barriers to achieving expected outcomes and reduce the effectiveness of an economically efficient pricing regime.

Our assessment of the relative importance of each NZEM objective will be considered in the context of whether the market model has contributed to the continuing availability of energy services at the lowest cost to the economy as a whole. This is one of NZEM's guiding principles, developed when the market was established.

## Approach Adopted

We have assessed the performance of the FNP regime in achieving each expected outcome by a combination of:

- statistical analysis of spot price outcomes;
- analysis of other observed electricity market outcomes;
- consideration of market participants' comments on market outcomes; and
- our appraisal of the key factors that have contributed to the observed outcomes for each objective.

Where we believe the market has failed to achieve an expected outcome we have highlighted key reasons for that failure.

The data analysis presented in this report has been based on information provided to us by M-Co. If any of this information is inaccurate or incomplete this report may have to be revised.

## Interpretation of Outcomes

Observed spot market outcomes since October 1996 can be attributed to:

- market design;
- industry structure;
- market size;

and the interaction between these and other factors over time.

Although issues unrelated to market design have had a significant impact on outcomes, our study has emphasised the features of FNP that have contributed to the outcomes observed. It is doubtful whether the relative contribution of market design and other factors to the observed outcomes can be objectively quantified on an empirical basis. In our view further analysis of information available to us on NZEM outcomes since 1996 is unlikely to support definitive conclusions on the relative contributions of market design and other factors to the observed outcomes.

Any queries on the meaning of any figures or statements in this report should be referred to Trowbridge. While due care has been taken in preparation of the report, Trowbridge accepts no responsibility for any action which may be taken based on its contents.

## Comparison of Actual and Expected Outcomes

This section summarises the key conclusions of the comparison of expected market outcomes with those actually achieved since the market commenced in 1996. The summary concentrates on the influence of FNP on the observed outcomes.

### Efficient Short-Run Operation

- FNP has achieved the efficient dispatch objectives of the market to the extent that market prices are determined by the competitive interaction of suppliers and buyers.
- The marginal loss pricing model adopted in the NZEM is consistent with efficient short-run operation of the market.
- Nodal prices signal the cost of electricity consumption with more accuracy than any other pricing regime but the benefit in terms of short-run demand-side participation in the electricity market is restricted by various impediments.
- Transpower’s current transmission pricing methodology recognises the trade-off between the distortion to short-run efficient usage of the grid and the distortion to long-term efficient usage of the grid.
- Predictable grid operation practices are key to achieving efficient short-run operation of the electricity system by enabling lower cost dispatch through flexible grid operation and making FNP signals more predictable.

## Efficient Long-Run Operation

- The location of new investment in generation capacity since 1996 appears to have been influenced by FNP – the main generation investments have been located close to Auckland.
- The influence of the FNP regime on the timing of new investment is less clear.
- There has not been major new investment to relieve transmission constraints despite a pronounced increase in inter-nodal price volatility over the period.
- There has been little evidence of significant demand-side response to nodal pricing signals.
- We believe that FNP contributes to the lack of contract market liquidity. A lack of contract market liquidity represents a barrier to investment by new entrant generators.

## Ability to Manage Risk

- FNP contributes to the lack of effective hedging alternatives to appropriately located physical generation. However, the high level of vertical integration in the industry is believed to be a major adverse influence on the availability of hedge contracts in the electricity market.
- The ‘basis risk’ associated with hedging load requirements at particular nodes is effectively unmanageable in the current market.
- Although FTRs will improve the ability of market participants to manage electricity price risk, in our view an FTR market may prove to be less effective than proponents would hope.
- Efficient investment in the transmission grid should result in fewer nodal price separation events and hence reduce the risks associated with inter-nodal trade.

### Effective Retail Competition

- The retail market is substantially regionalised at present. To the extent that FNP reduces liquidity in the contract market it is also an impediment to retail competition on a national basis.
- Improvements to the allocation of L&CS and any other steps that enhance the ability of market participants to manage risk in the NZEM can be expected to have a beneficial effect on retail competition.
- In the absence of investment to reduce financially significant transmission constraints, and without greater demand-side response to price signals, the FNP regime appears to be less effective in facilitating national retail competition than a pricing regime based on fewer nodes.

### Competitive Price Discovery

- FNP does not cause the high price spikes that occur at nodes affected by transmission constraints.
- Information on high price outcomes at specific nodes will be clearer to market participants and end-users under FNP than under alternative pricing regimes based on fewer nodes and greater socialisation of costs.
- The expectation that prices would be discovered at each node by the competitive interaction of buyers and sellers has not been achieved when transmission constraints prevent load at particular nodes from importing cheaper power. The lack of effective real-time demand-side response to spot market price signals adds to the potential for non-competitive price outcomes.
- The economic impacts of high nodal prices on users who lack practical means to respond to those prices can be severe.

## Overall Conclusion

Our analysis of the available information on market outcomes since 1996 has not identified strong evidence to date of significant benefits related to the accurate signalling properties of FNP. However, there is evidence of a pronounced increase in price separation between nodes and day-to-day price variations at individual nodes.

Where market outcomes that the FNP model was expected to achieve have not emerged the causes of failure can, in many cases, be attributed to factors unrelated to FNP. Our report discusses the influence of a number of these factors on market outcomes.

A pricing regime based on fewer 'representative' nodes (a zonal model) offers benefits from risk management and retail competition perspectives. However a zonal model would distort the investment incentives provided by the FNP model and potentially introduce gaming opportunities associated with the rules necessary to implement a zonal pricing model.

Evaluating the relative merits of alternative market design options is critically dependent on the relative weightings attributed to economic efficiency and equity criteria. A further pre-requisite for any evaluation of alternative market design options would be to agree a definition of the equity objectives of the market.

Any proposal to change the market design needs to take account of the current industry structure and recent developments aimed at addressing important shortcomings in the current market. These include provisions to establish a consultative forum to address problems associated with transmission investment[1] and the ongoing development of a transmission hedging instrument to address problems associated with inter-nodal price differences.

[1] Part F of the proposed Rule Book governing New Zealand's electricity arrangements

# Part II Detailed Findings

## 1 Introduction and Scope

### 1.1 Full Nodal Pricing

The FNP regime applied in the NZEM establishes the price of providing energy at each grid injection and exit point on the transmission network. Nodal prices represent the change in the total cost (as represented by market participants' bids and offers) of meeting system energy requirements caused by a change in load or generation at each node. Therefore, in the NZEM, nodal prices incorporate the effects of power losses and line constraints on the total cost of meeting system load requirements. Nodal prices are also affected by the price of reserve. This is a result of the trade-off between the cost of energy and reserve arising from the co-optimisation of energy and reserve markets.

Prices are established at each node for each half-hour. Since February 2000 final prices are (normally) available by midday following the day's trading.

The FNP regime was adopted when New Zealand's wholesale market was established in October 1996. A key consideration in adopting nodal pricing for the NZEM was its consistency with the efficiency goals that had driven the restructuring and reform of the market[2].

### 1.2 Scope

Trowbridge Deloitte (Trowbridge) has been engaged by the Rules Committee of the NZEM to assess, on an empirical basis, whether the Full Nodal Pricing regime has achieved the outcomes expected at market commencement. For the purposes of our study FNP is taken to include:

[2] See 'Implementation of Nodal Pricing in the NZEM'; a document prepared by the Dispatch Rules Working Group in May 1996.

(a) the mechanism by which prices are determined;

(b) the collection of loss and constraint settlement surplus (L&CS); and

(c) the subsequent allocation of L&CS from grid owner through to end recipients.

The scope of our study includes:

- determining the outcomes expected when the market was established;
- examining market outcomes to assess whether these outcomes have been achieved; and
- where expected outcomes have not been achieved – investigating the reasons for non-achievement.

## 1.3 Consultative Process

Although the opinions expressed in this report are those of Trowbridge we wish to acknowledge the input of NZEM market participants.

We commenced the study by consulting with market participants to determine outcomes expected when the market was established and to identify key concerns with the current market design. These interviewees are listed in Appendix A.

We also attended a meeting of the Rules Committee held on 2 May 2002 to discuss our findings on the outcomes expected from the FNP regime when the market was established. The Rules Committee agreed that the expected outcomes we proposed were appropriate criteria against which actual outcomes should be measured.

Following this meeting M-Co provided load, price and generation data covering all market nodes for the period from October 1$^{st}$ 1996 to the end of April 2002. We analysed this data for evidence of outcomes consistent with expectations prior to the commencement of the market and presented our preliminary conclusions to the Rules Committee at a meeting held in Wellington on 5 September 2002.

These expected outcomes are discussed in section 2.

## 1.4 Approach Adopted

We have assessed the performance of the FNP regime in achieving each expected outcome by a combination of:

- statistical analysis of spot price outcomes;
- analysis of other observed electricity market outcomes;
- consideration of market participants' comments on market outcomes; and
- our appraisal of the key factors that have contributed to the observed outcomes for each objective.

Where we believe the market has failed to achieve an expected outcome we have highlighted key reasons for that failure.

The data analysis presented in this report has been based on information provided to us by M-Co. If any of this information is inaccurate or incomplete this report may have to be revised.

## 1.5 Interpretation of Outcomes

Observed spot market outcomes since October 1996 can be attributed to:

- market design;
- industry structure;
- market size;

and the interaction between these and other factors over time.

Although issues unrelated to market design have had a significant impact on outcomes, our study has emphasised the features of FNP that have contributed to the outcomes observed. It is doubtful whether the relative contribution of market design and other factors to the observed outcomes can be objectively quantified on an empirical basis. In our view further analysis of information available to us on NZEM outcomes since 1996 is unlikely to support definitive conclusions on the relative contributions of market design and other factors to the observed outcomes.

Any queries on the meaning of any figures or statements in this report should be referred to Trowbridge. While due care has been taken in preparation of the report, Trowbridge accepts no responsibility for any action which may be taken based on its contents.

# 2 Expected Outcomes

## 2.1 Background

New Zealand's electricity market reforms leading up to the introduction of the FNP regime in October 1996 were part of a wide range of micro-economic reforms instigated by government in the mid 1980s. The objective of these reforms was to stimulate economic growth through efficient resource use driven by clearer price signals and, where possible, by competitive markets[3].

The guiding principle of the energy policy framework was to ensure that energy services continue to be available at the lowest cost to the economy as a whole consistent with sustainable development. The introduction of competitive market-based structures was intended to drive increased efficiencies in the electricity industry. When the wholesale market commenced operations in October 1996 FNP was adopted as the pricing regime most appropriate to the aims of the market reforms.

## 2.2 'Efficiency' Requirement

The specific outcomes that were expected to be achieved by the FNP regime were developed subject to an overall efficiency requirement. In the context of energy markets 'efficiency' means:

- the output is produced by the cheapest suppliers;
- it is consumed by those most willing to pay for it; and
- the right amount is produced.[4]

[3] 'Chronology of New Zealand Electricity Reform' prepared by Energy Markets Policy Group – available on the Ministry of Energy's website.

[4] Stoft – Power System Economics, page 53.

FNP can be regarded as an idealised model for an efficient electricity market, accurately signalling the cost of incremental electricity consumption. In theory FNP signals ensure that:

- in the short-run electricity is allocated to its highest-value uses (allocative efficiency); and
- in the long-run the timing and location of new investment ensures continued allocative efficiency (dynamic efficiency).

The consistency of FNP with the economic efficiency objectives of government reforms was regarded as a significant advantage of the pricing regime. Consideration of the impact of FNP on liquidity in the contract markets where participants trade risk management instruments was secondary to ensuring efficient pricing in the wholesale spot market.

## 2.3 Basis for Determining Expected Outcomes

In the absence of a single document stating the expected outcomes of the FNP regime we reviewed a number of reports and discussion documents prepared prior to the market's commencement that address the application of nodal pricing to the NZEM. We also consulted with market participants to determine the outcomes they expected from the market when it was established. Combining the information provided by these sources we identified 5 key outcomes that the FNP regime was expected to achieve.

## 2.4 The 5 Expected Outcomes

The expected market outcomes that we have measured actual outcomes against are:

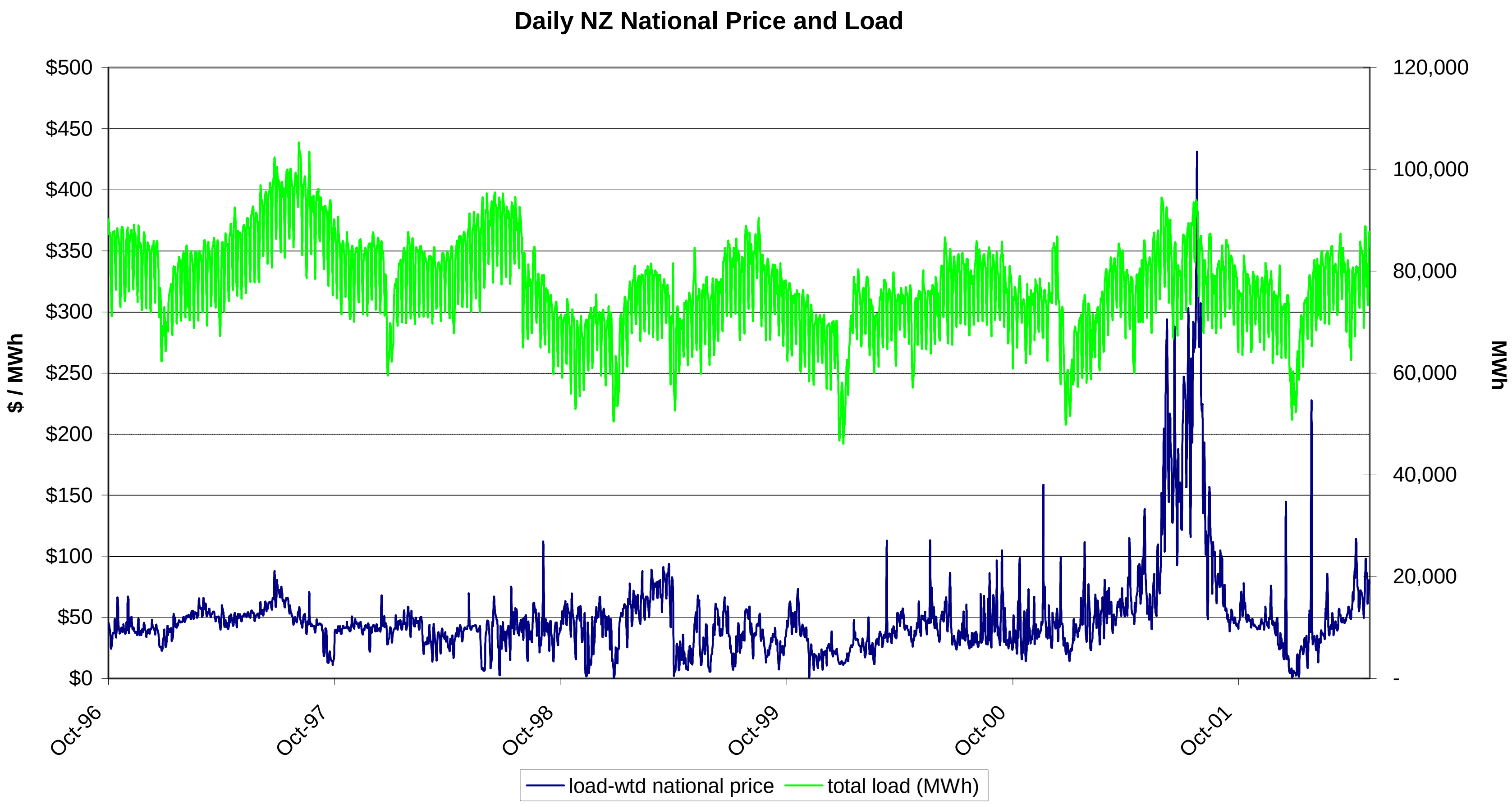
- Efficient short-run operation;
- Efficient long-run operation;
- Ability to manage risk;
- Effective retail competition; and
- Competitive price discovery.

Each of these expected outcomes are discussed in detail in the following sections of the report.

## 2.5 Spot Market Outcomes over the Period

The following chart shows the time series of daily national (load-weighted) spot price and load over the period from the commencement of the market in 1996 to April 30th 2002. The chart provides a useful overview of market outcomes over the last $5^1/_2$ years. In particular, the price and load spikes in 2001 illustrate the extreme market outcomes associated with the cold dry conditions in the winter of 2001.

**Chart 2.1**


Daily NZ National Price and Load
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
$ / MWh
120,000
100,000
80,000
60,000
40,000
20,000
-
MWh
Oct-96
Oct-97
Oct-98
Oct-99
Oct-00
Oct-01
load-wtd national price
total load (MWh)

# 3 Efficient Short-Run Operation

## 3.1 What Outcomes were Expected?

The ability of nodal pricing to provide all the signals required for efficient short-run operation of the electricity market was considered a key advantage of the pricing regime when it was adopted in 1996. Assessing the efficient short-run operation of the market is focussed on determining whether the FNP model has been effective in achieving efficient dispatch of plant to meet system demand, taking into account constraints on the transmission system.

## 3.2 Assessment of whether Expected Outcomes were Achieved

Testing whether the FNP model results in efficient dispatch is essentially a test of whether the dispatch algorithm solves correctly. We have not undertaken a check of the dispatch algorithm for the purposes of this study. Our assessment of whether the FNP regime has achieved efficient short-run operation of the NZEM is based on discussions with market participants and analysis of documentation of how the market operates, including submissions to the Minister of Energy's 2001 Post Winter Review (PWR).

## 3.3 Conclusions

Nodal pricing is effective in signalling the incremental cost of meeting load at each node on the transmission system. Nodal prices represent the change in the total cost of meeting system energy requirements caused by a change in load or generation at each node. In the NZEM, nodal prices incorporate the effects of power losses and line constraints on the total cost of meeting system load requirements.

There is consensus among market participants that FNP is achieving efficient dispatch – this is an inherent feature of the NZEM pricing model. However, to assess whether the market is operating efficiently in the short-run depends on the definition of what constitutes the market. If the market is taken to include the contract market where participants trade risk management instruments and the retail market where end-users purchase their electricity requirements, then it is less clear that the market as a whole is being operated efficiently in the short-run. In our view the use of nodal prices for spot purchases has had negative impacts on both the liquidity of the contract market and competition in the retail market. The idea that, from a market design perspective, there is a trade-off between accuracy in spot market pricing and liquidity in the contract market is discussed in more detail in following sections.

## Key Issues Affecting Outcomes

### Efficient Dispatch

Market participants that purchase energy on the spot market are required to meet the cost their incremental usage will impose on the system. The generator (or demand-side participant) that can meet the change in system energy requirements at least cost, taking system security constraints into account, is dispatched to meet the change in load. Therefore, to the extent that market prices are determined by the competitive interaction of suppliers and buyers, FNP achieves the efficient dispatch objectives of the market. The output is produced by the cheapest suppliers and is allocated to highest value uses (to the extent that the price paid by consumers reflects the value they place on energy inputs).

### Marginal Loss Pricing

Some participants have questioned whether marginal loss pricing is efficient. In our opinion marginal loss pricing is efficient. If losses limit the dispatch of distant generation, then marginal loss pricing results in a more efficient dispatch than average loss pricing. Using average loss pricing, greater quantities of distant generation are dispatched than would be dispatched using marginal loss pricing and transmission losses are correspondingly higher. Therefore, where losses limit the dispatch of distant generation, the total cost of meeting a given load from distant and local generation and the quantity of energy generated to meet the load is always higher using average cost pricing. If line congestion rather than marginal losses limits imports of energy, then the method of pricing for losses will not change the dispatch order. Appendix B sets out the algebra supporting these conclusions.

## Demand-Side Participation

Nodal prices provide appropriate signals for demand-side response in the electricity market. Demand-side participants that are exposed to nodal prices are given clear signals of the costs of their electricity consumption. However, the ability of demand-side participants to respond to these signals is impeded by a number of factors unrelated to FNP. The impediments include:

- The inability of many major users to respond to price signals because their industrial processes require considerable lead-time to adjust energy use[5];
- The cost associated with technological and procedural changes required to enable industrial loads to respond to nodal price signals[6];
- The structure of retail tariffs (typically highly averaged and fixed for periods of at least one year) results in few domestic customers being exposed to wholesale market price signals[7]; and
- The cost of the technology required to monitor and manage domestic usage in real-time.

These difficulties in developing a genuinely two-sided spot market for electricity are common to most deregulated electricity markets and represent an important obstacle to achieving efficient short-run operation in electricity markets. Therefore, although nodal prices signal the cost of electricity consumption with more accuracy than other pricing regimes, the benefit in terms of short-run demand-side participation in the electricity market remain largely unrealised.

Proposals to introduce real-time pricing to the spot market will improve price signals by providing greater certainty to market participants about nodal price outcomes. However, we believe that the benefit to the market in terms of efficient operation is unlikely to be significant while other impediments remain.

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[5] Differences between forecast and final prices mean that the potential savings from load management cannot be quantified with certainty when the decision whether or not to adjust load is made.

[6] If energy costs represent a small proportion of total operating costs then industrial users are not likely to be interested in demand-side initiatives.

[7] Domestic and small business customers are typically resistant to accepting pool price exposure.

## Transmission Pricing

'Cost-reflective' recovery of the sunk costs of the transmission grid distorts the marginal pricing signals provided by FNP. The NZEM's nodal spot prices signal the marginal cost of transmission usage associated with a change in load at each node. Recovery of the sunk costs of the grid necessarily changes the marginal price faced by loads away from the economically efficient price.

Preserving economically efficient price signals is clearly an important consideration in the appraisal of any proposed changes to NZEM arrangements. However, as in the case of transmission pricing, other considerations may make some distortion to price signals unavoidable.

We have not attempted to ascertain whether Transpower's charging basis for recovery of sunk costs[8] has had a material impact on the short-run efficient operation of the market. This would be difficult to establish based solely on an analysis of the available empirical evidence.

[8] Transpower recovers sunk interconnection costs using a charge based on peak demand. This method aims to recover costs based on offtake customers' usage of peak capacity. The charge provides incentives for load management that are not consistent with short-run efficient use of the transmission grid as signalled by the marginal price of losses and congestion. Transpower's method of allocating the interconnection charge based on the average of the highest 12 offtake peaks for the previous year aims to reduce the distortion to short-run efficient pricing.

A more averaged transmission charging basis such as a fixed charge per MWh consumed would increase the price faced by each consumer by a fixed amount at each level of consumption. Therefore the recovery of sunk costs would be independent of time-of-use, location and level of consumption. This would provide incentives for individual customers to take less energy from the grid relative to other loads (i.e. reduce their share of total grid usage). However, if the overall requirement for grid capacity does not reduce in proportion to the energy taken from the grid, this method may provide inefficient long-term incentives to under-utilise the grid.

A charge for sunk costs of the transmission grid that is related to peak demand but is sufficiently averaged to dampen short-run incentives for load management provides a reasonable trade-off between the distortion to short-run efficient usage of the grid associated with a charge based on annual peak demand and the distortion to long-term efficient usage of the grid associated with a charge based on each customer's total demand.

## Transmission Grid Operation

The operation of the transmission grid has a significant impact on nodal pricing outcomes. Decisions of the grid operator and/or the grid owner can lead to nodal price outcomes with significant financial consequences for market participants. A number of submissions to the Post Winter Review (PWR) highlighted the need for the grid operator to consider the trade-off between system security and the cost of meeting load requirements through more flexible and dynamic grid operation. Predictable grid management is key to achieving efficient short-run operation of the electricity system by enabling lower cost dispatch and making FNP signals more predictable.

This is a complex issue that we have not considered in detail. However, in our opinion this issue merits further attention to assess the magnitude of benefits that could be achieved in providing electricity at lower cost to the economy as a whole. Any resulting changes to the risk profile of the grid owner and/or the grid operator should be combined with an appropriate incentive structure to reward efficient grid management.

# 4 Efficient Long-Run Operation

## 4.1 What Outcomes were Expected?

The efficient long-run investment signals provided by the FNP market model were expected to result in efficient location and timing of new investment in electricity generation, transmission and demand-side infrastructure.

## 4.2 Assessment of whether Expected Outcomes were Achieved

To assess whether market outcomes have been consistent with this expected outcome we need to answer the following questions:

- Have infrastructure investments been undertaken at nodes facing high prices?
- Has electricity usage at low price nodes increased relative to usage at high price nodes?

### Data Analysis

Our analysis of market outcomes over the last $5^1/_2$ years has considered:

- the variability of inter-nodal spot prices; and
- the pattern of demand by node.

The data analyses are described below.

## Variability of Inter-Nodal Spot Prices

By analysing the development of an index of inter-nodal price differences since 1996 we have investigated whether inter-nodal price differences are reducing over time due to (for example):

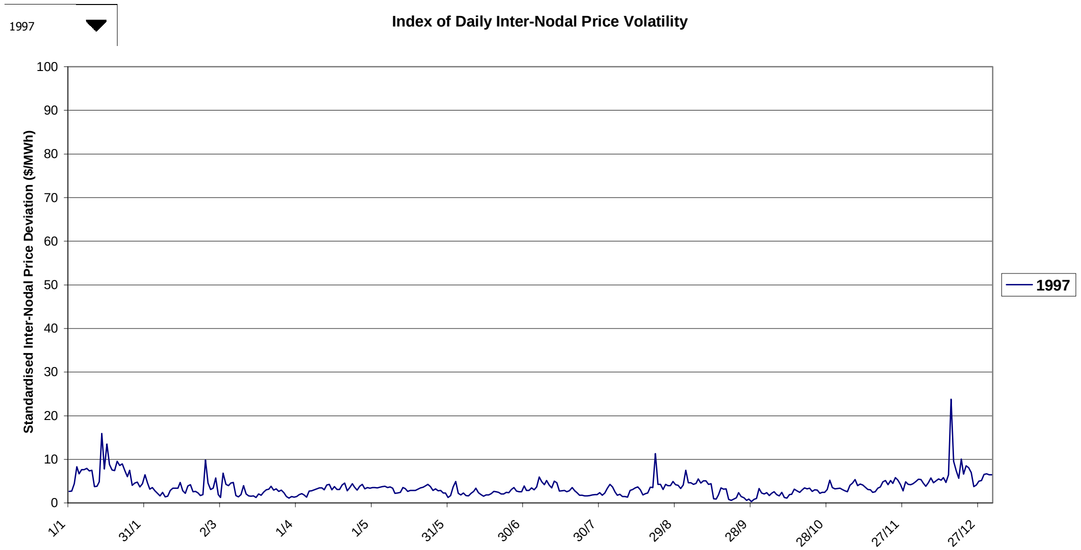
- New investment acting to relieve constraints and reduce price difference between nodes; or
- Demand-side response to price signals.

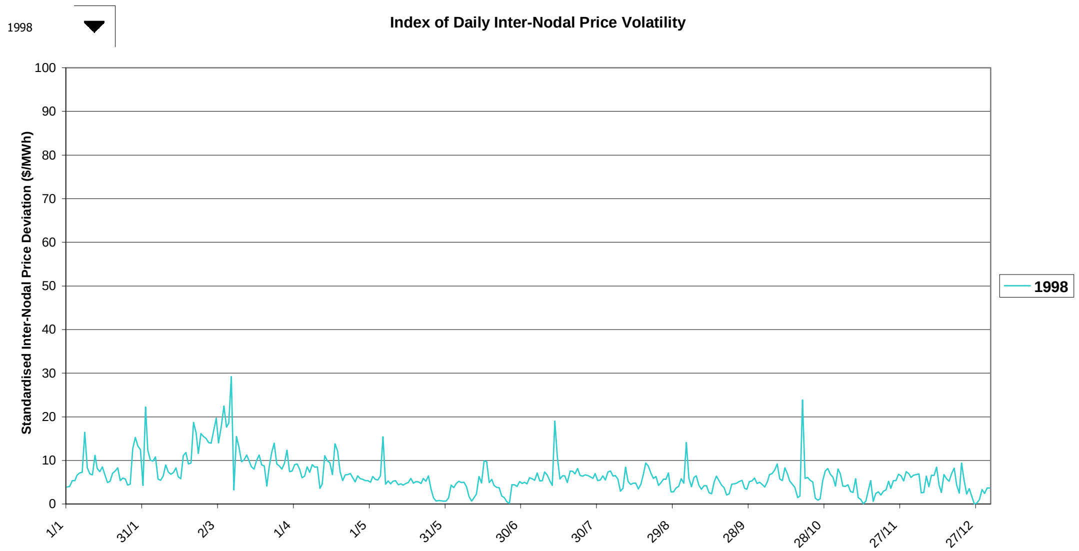
We have analysed inter-nodal price differences over time by studying the development of an inter-nodal price volatility statistic calculated for each day from October 1996 to April 2002. This statistic measures the deviation of prices at each node from the national load-weighted average price for each day[9]. The following charts show the time series of daily values of this statistic for each full year since the market was established and for all years together. The outcomes show increasing inter-nodal price variability from the levels experienced in 1997. The charts illustrate that the high average prices experienced in 2001 were also accompanied by the highest level of inter-nodal price separation since the market was established. To facilitate comparison between years we have charted the daily price deviations on a consistent scale each year. For 2001 and 2002 we have truncated extreme daily deviations at $100/MWh.

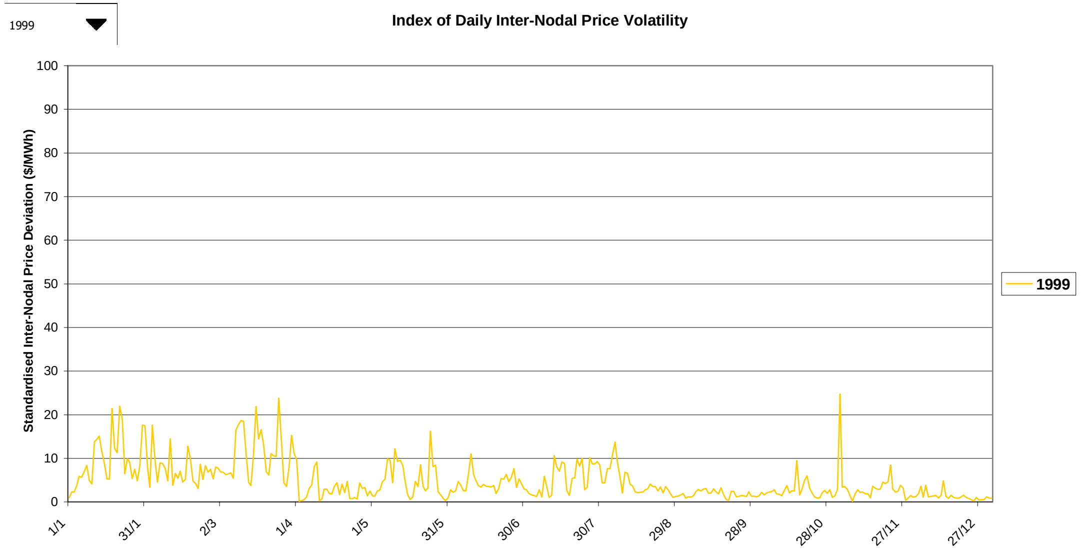
The observed outcomes are not consistent with the expectation that nodal pricing signals would act to encourage investment to reduce price differences between nodes. Five years may not be a sufficient time period to assess whether nodal prices are effective in delivering appropriate investment in electricity infrastructure, but the empirical evidence over the five full years of market operation to date shows an increasing level of price separation rather than convergence of nodal prices as a result of efficient timing and location of new investment.

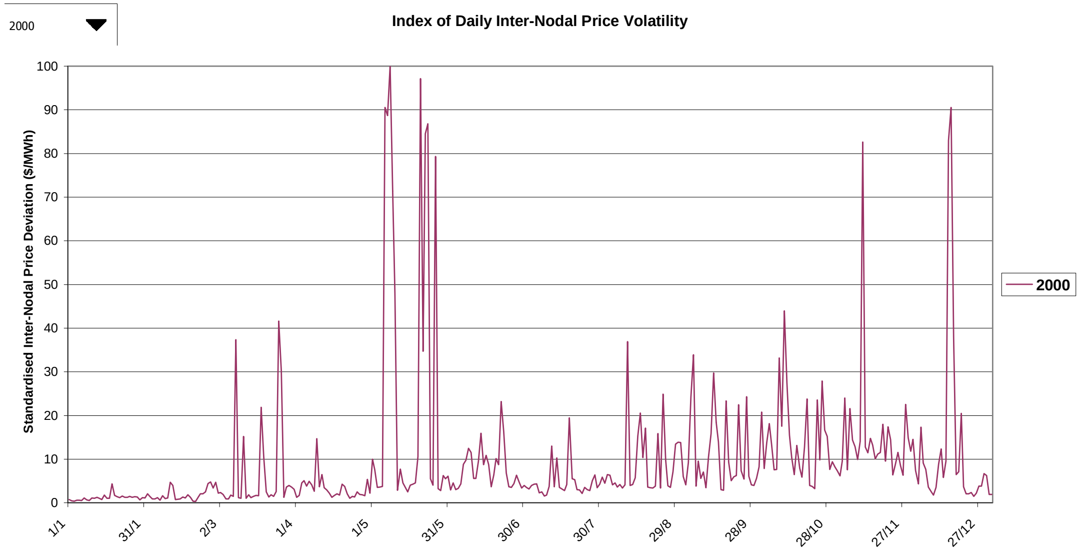
[9] The calculation of the daily inter-nodal price volatility statistic is described in Appendix C.

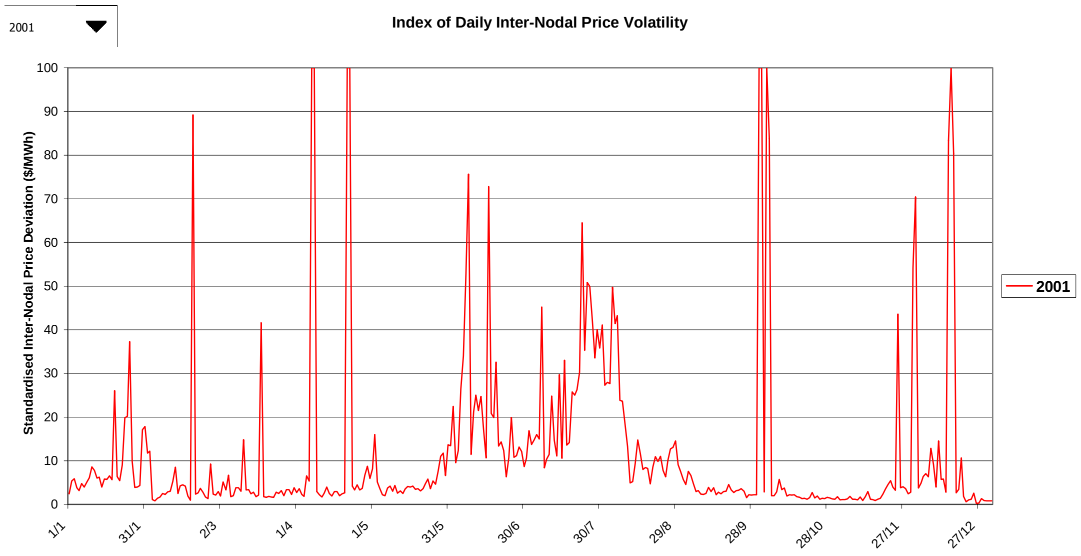
## Chart 4.1 – Inter-Nodal Price Volatility 1997 – 2001 inclusive

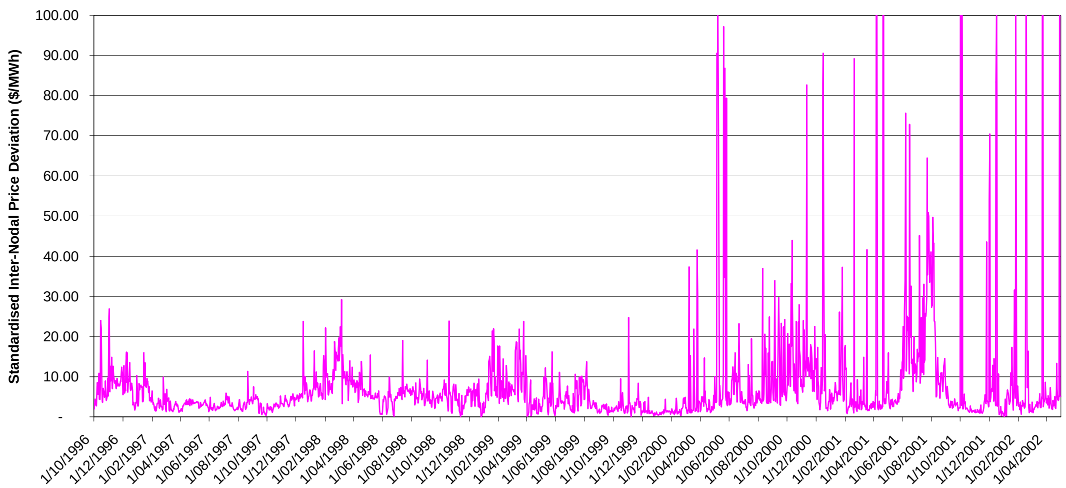



1999
Index of Daily Inter-Nodal Price Volatility
Standardised Inter-Nodal Price Deviation ($/MWh)
100
90
80
70
60
50
40
30
20
10
0
1/1
31/1
2/3
1/4
1/5
31/5
30/6
30/7
29/8
28/9
28/10
27/11
27/12
1999


2000
Index of Daily Inter-Nodal Price Volatility
Standardised Inter-Nodal Price Deviation ($/MWh)
100
90
80
70
60
50
40
30
20
10
0
1/1
31/1
2/3
1/4
1/5
31/5
30/6
30/7
29/8
28/9
28/10
27/11
27/12
2000


2001
Index of Daily Inter-Nodal Price Volatility
Standardised Inter-Nodal Price Deviation ($/MWh)
100
90
80
70
60
50
40
30
20
10
0
1/1
31/1
2/3
1/4
1/5
31/5
30/6
30/7
29/8
28/9
28/10
27/11
27/12
2001


Index of Daily Inter-Nodal Price Volatility - All Years
Standardised Inter-Nodal Price Deviation ($/MWh)
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
1/10/1996
1/12/1996
1/02/1997
1/04/1997
1/06/1997
1/08/1997
1/10/1997
1/12/1997
1/02/1998
1/04/1998
1/06/1998
1/08/1998
1/10/1998
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1/06/2000
1/08/2000
1/10/2000
1/12/2000
1/02/2001
1/04/2001
1/06/2001
1/08/2001
1/10/2001
1/12/2001
1/02/2002
1/04/2002

## Changing Pattern of Demand

To assess whether data indicates that price has influenced electricity usage over time we have investigated whether demand is:

- falling at nodes where average price is higher than the national average; and
- rising at nodes where average price is lower than the national average.

We investigated the response of demand to nodal price signals by ranking average nodal prices and average load at each node for each full year from 1997 to 2001 inclusive, and studying the correlation between the ranking of nodes from year to year. The following correlation matrices summarise the year-to-year correlations for nodal price and load rankings separately. The effect of average prices falling at high price nodes and rising at low price nodes would be reflected in reducing correlation between consecutive years' price rankings. We calculated the correlation of load rankings from year to year to investigate whether significant changes in nodal price rankings have been mirrored by changes in nodal demand.

The tables show high correlation between nodal ranking for both price and load for each year from 1997 to 2000, providing little evidence of demand response causing nodal prices to converge. In 2001 the correlation between the rankings of nodes on an average price basis is much lower than for previous years (38% correlation with the previous year's rankings compared to 86% for years 2000 and 1999). This is consistent with the effect of the dry cold winter in 2001 on electricity market outcomes as a hydro shortage resulted in a reversal of the normal northward flow of electricity from hydro generators in the South Island and an associated increase in the level of thermal generation in the North Island.

However, this change in ranking of nodes on a price basis was not mirrored in the rankings on the basis of average annual load. The correlation of load-based rankings between 2000 and 2001 is 97%.

Even though rankings based on load are likely to be more stable from year to year than rankings based on price, this result provides a useful measure of the relative insensitivity of electricity demand to price. Although the NZEM (load-weighted) average price in 2001 was $90.63/MWh compared to $40/MWh in 2000, load increased by close to 5% over the previous year. The increase in load despite a doubling in price can be explained by many factors including the effect of the cold winter on heating-related demand and low rainfall on hydro supply, but the outcome does illustrate the limited influence of wholesale market price on electricity demand.

### Table 4.1 – Rank Correlation Matrices

***RANK CORRELATIONS - AVERAGE ANNUAL NODAL PRICES***

| | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|
| **1997** | 1.00 | | | | |
| **1998** | 0.91 | 1.00 | | | |
| **1999** | 0.90 | 0.88 | 1.00 | | |
| **2000** | 0.83 | 0.86 | 0.86 | 1.00 | |
| **2001** | 0.39 | 0.26 | 0.40 | 0.38 | 1.00 |

***RANK CORRELATIONS - AVERAGE ANNUAL NODAL LOADS***

| | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|
| **1997** | 1.00 | | | | |
| **1998** | 0.98 | 1.00 | | | |
| **1999** | 0.97 | 0.98 | 1.00 | | |
| **2000** | 0.95 | 0.96 | 0.99 | 1.00 | |
| **2001** | 0.94 | 0.95 | 0.96 | 0.97 | 1.00 |

## 4.3 Conclusions

### Generation Investment

#### Location

The location of new investments in generation capacity close to the Auckland demand centre at Otahuhu, Southdown and Glenbrook has been influenced by FNP. The location of load close to growing load centres minimises the cost of transmission for a new generator under a FNP regime. An alternative pricing regime that did not signal the marginal cost of transmission at each node as accurately as FNP could have resulted in some of the generation investments since 1996 locating close to fuel sources rather than demand centres.

However, the proposed development of up to 570MW of new hydro generation capacity by Meridian Energy on the lower Waitaki River emphasises that FNP is just one of many factors that influence the location of new investments in generation capacity. Assessed solely according to FNP criteria a new investment in generation capacity would be located closer to the North Island load centres rather than in the lower South Island. Proximity to fuel and the relative costs of electricity transmission compared to fuel transportation costs are important factors affecting decisions on the location of new investments. In some situations these factors will be of greater importance than the impact of losses and constraints on the cost of delivering energy to load.

#### Timing

The influence of the FNP regime on the timing of new investment is difficult to gauge even over the period since 1996. Forward projections of supply / demand balance included in PWR submissions indicate an increased risk of dry year supply shortfalls over the next few years. The level of prices prior to 2001 has been cited as the key factor discouraging investors from committing to new plant investment. On this basis the spot price signals provided by the FNP regime do not appear to have been sufficient to ensure efficient timing of new investment in the NZEM. Factors unrelated to the pricing regime such as uncertainties regarding the availability of firm supplies of fuel and delays in environmental approvals also influence the timing of investment. These factors would apply irrespective of the pricing regime employed.

## Transmission Investment

FNP signals have not been sufficient to stimulate major new investment in the transmission grid. Documents prepared by the Dispatch Review Working Group (DRWG) in 1996 anticipated coalitions of users responding to high nodal prices caused by transmission constraints by investing in augmentations to the transmission grid. This has not occurred to any significant extent since market establishment despite many instances of nodes experiencing sustained high energy prices due to transmission constraints.

In most other deregulated electricity markets transmission investment decisions involve some form of centralised planning process. This is not the case in the NZEM at present. The grid operator undertakes investment in the transmission network where security of supply is threatened but avoids "unilateral investment decisions which result solely in changes to nodal prices and thus to the commercial positions of energy market participants"[10].

The reliance on investment in the transmission grid on a commercial basis in response to nodal price signals is unlikely to result in efficient investment in the transmission grid. There are many impediments to private investment in the grid that prevent market participants and major energy users responding to nodal price signals. These include:

- Inability to capture the benefit of the avoided cost of transmission investment - A private investor who invests to augment the transmission grid and relieve constraints will benefit only to the extent that the investment provides access to cheaper energy for their usage requirements[11]; and
- Characteristics of network investments - Transmission augmentations are lumpy investments involving complex network effects and substantial economy of scale benefits. These characteristics will tend to deter investors if investing in and maintaining transmission assets is not their core business.

[10] Transpower's cross submission to the Post Winter Review, page 4

[11] The benefits to other users at the same node and network-wide benefits arising from the private investor's grid enhancement are essentially free-rider benefits to those other grid users. A Financial Transmission Right (FTR) issued to the private investor will only provide insurance to the investor against the risk of other participants using up the new capacity on the transmission link restoring high prices at the downstream node.

At present there is no appropriate forum within which to assess the market-wide and economy-wide benefits of investment in the electricity network and in particular the core interconnected grid. However, we understand that the proposed Rule Book governing New Zealand's electricity market arrangements includes provision for a consultative forum that would enable Transpower and market participants to agree service definitions and measures and to consider new transmission investment as a potential option to relieve constraints even where security of supply is not at risk. It is important that this forum would take into account the market-wide and economy-wide benefits of greater interconnection (including the consequent reduction in inter-nodal price volatility) and provide for Transpower to invest to meet service levels where private investment is assessed to be an unrealistic alternative.

The benefits of improved interconnection include the reduction of local market power at nodes subject to transmission constraints and the reduction in risk management costs associated with lower inter-nodal price volatility. A transmission investment framework that does not acknowledge these benefits is unlikely to result in efficient long-run system operation.

### Demand-Side Investment

As discussed in section 3.3 there are a number of structural impediments to active demand-side participation in the NZEM. These structural impediments to efficient short-run operation of the market have a corresponding effect on long-run efficient operation of the market.

### Illiquid Contract Markets

A number of market participants have commented on the lack of liquidity in contract markets for risk management instruments. The liquidity of the contract market is affected by a number of factors unrelated to the pricing regime. In particular the high level of vertical integration in the industry is a major influence on the availability of hedge contracts in the electricity market. Where a large proportion of the generation output of vertically integrated companies is hedged by their retail load the market for hedge contracts is unlikely to be liquid.

However, we believe that FNP also contributes to the lack of contract market liquidity. Participants are interested in hedging price risks at particular nodes only. When interest in hedging contracts is spread across up to 240 nodes in a market with maximum annual consumption of approximately 28TWh, the liquidity at many nodes is likely to be poor. For a market of a given size the number of counterparties interested in contracting at each node necessarily reduces as the number of nodes increases. A reduction in the number of counterparties leads to a reduction in the liquidity of each nodal market. A pricing regime based on fewer, representative nodes would increase the number of counterparties interested in contracting at each of the reduced number of nodes.

Transmission hedges that utilise inter-nodal settlement surpluses to enable market participants to partially hedge inter-nodal price differences should enhance the liquidity of contract markets. This would apply under FNP and alternative pricing regimes based on fewer nodes.

It is our opinion that, from a practical risk management perspective, the existence of a transmission hedge product does not put a retailer supplying customers at many nodes under a full nodal pricing regime in the same position as a retailer operating in a market where pool purchases are referred to fewer prices.

Although it is possible to replicate a hedge at a particular node by combining a hedge at another node with an appropriate transmission hedge, this procedure is more complex. The success of the replication approach depends on:

- securing transmission hedges between the relevant nodes at an acceptable price;
- matching the volume and duration of the component hedges; and
- the transmission hedge being materially firm.

Poor contract market liquidity can be a significant barrier to investment by new entrant generators. A new entrant generator will typically seek to contract a proportion of its output to underwrite investment in new plant. Therefore, a lack of liquidity in the contract market will restrict the new entrant's ability to lock in stable revenue to meet financing requirements. This clearly has negative implications for the efficient long-run operation of the market.

# 5 Ability to Manage Risk

## 5.1 What Outcomes were Expected?

The ability to manage price risk is critical in a market where more than 240 nodal prices are established every half-hour.

The DRWG envisaged in 1996 that "trading under a FNP regime will give rise to new financial hedging instruments"[12].

The ability of market participants (MPs) to manage price risk is focussed on two key areas:

- Can MPs enter into hedge contracts to control energy price volatility at each node where they use/ retail electricity?
- Can electricity users/retailers acquire transmission hedges to fix the unit price for contracted power that is generated at other nodes?

In both cases the ability to contract implies hedging at a 'reasonable' cost.

## 5.2 Assessment of whether Expected Outcomes were Achieved

The absence of public data on hedge contract prices, terms and trading volumes prevents us from analysing contract market outcomes. Comments made by market participants during our initial consultations indicated that there is wide agreement that the contract market is not deep or liquid. In the absence of statistics on contract market outcomes our data analysis has been confined to wholesale spot market outcomes. The purpose of the following data analyses is to quantify the risks that market participants need to manage. Their ability to manage these risks is discussed subsequently.

[12] Implementation of Nodal Pricing in the NZEM, page 14 (document prepared by the DRWG)

## Data Analysis

We have analysed the following measures to assess the risks faced by market participants since 1996.

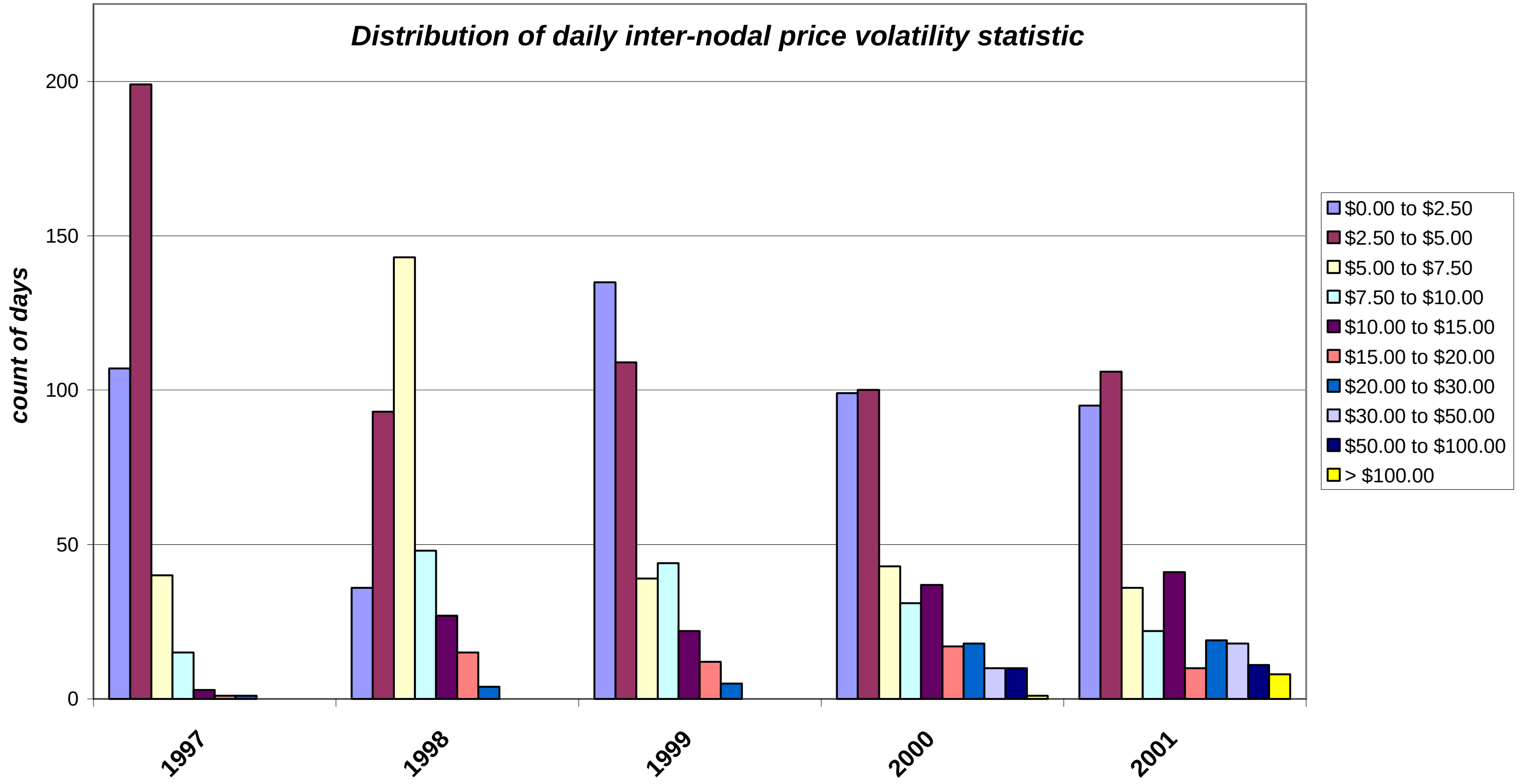
### Inter-Nodal Price Differences

The measure of inter-nodal price differences discussed in section 4.2 is a useful indicator of one of the key price risks associated with FNP. The charts of the time series of inter-nodal price variations showed an increasing level of inter-nodal price separation since 1997.

The following chart shows the distribution of the inter-nodal price volatility statistic for each year. Consistent with the time series charts in section 4.2 the yearly distributions show greater nodal price deviations from the daily (load-weighted average) national price over the period from 1997 to 2001. The distributions charted below also illustrate the wider spread of deviations from the national price across nodes, highlighting the increased risk of inter-nodal trade since the NZEM was established in 1996.

The calculation of the daily inter-nodal price volatility statistic is described in Appendix C.

**Chart 5.1 – Distribution of daily inter-nodal price deviation**



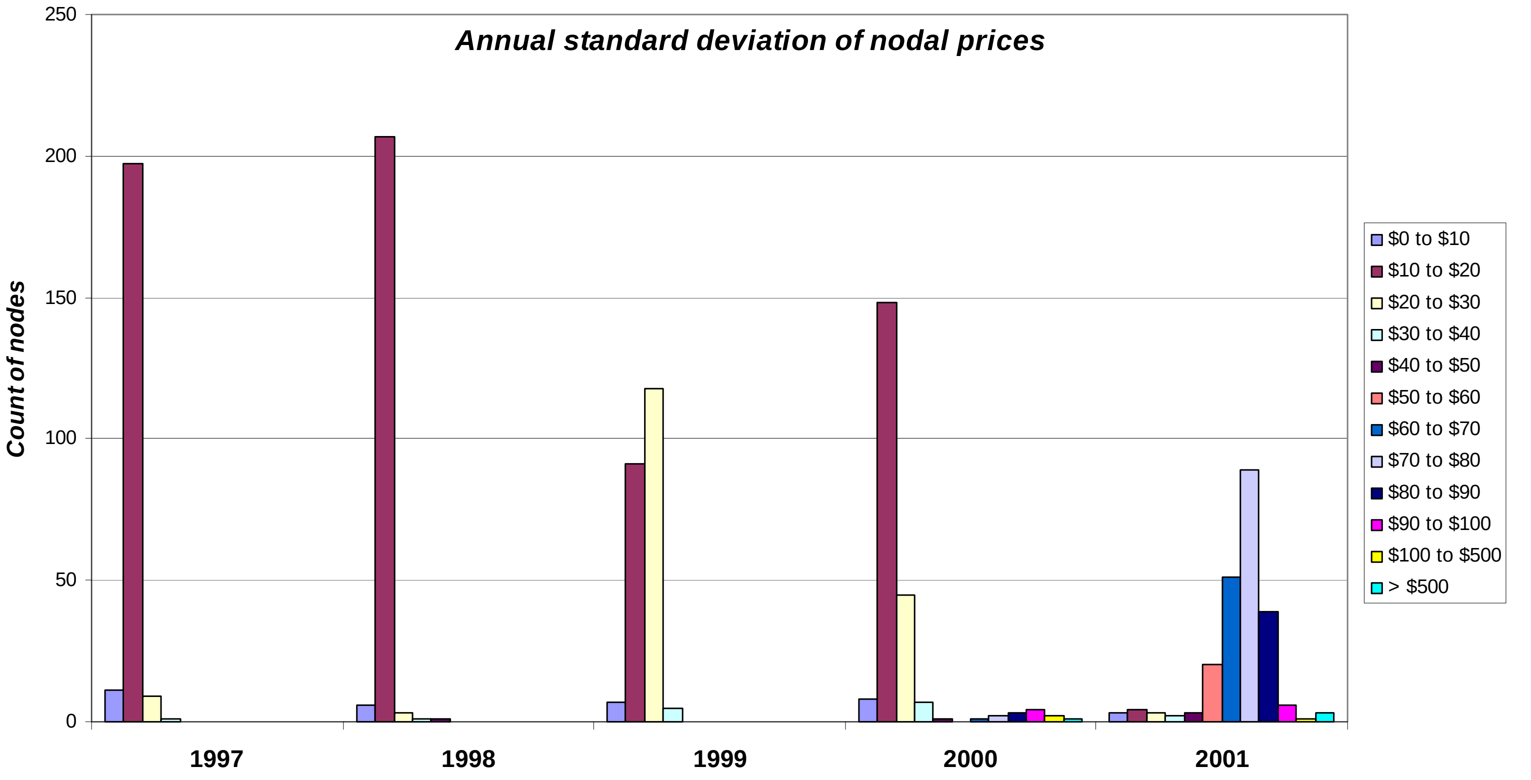
## Within-Node Price Variability

The following chart shows the distribution of the annual standard deviation of price at each node. This measures the day-to-day deviation from the average price for the year at each node. The chart shows the distribution of this measure of within-node price variability across all nodes for each full year since the market was established.

In 1997 and 1998 the variability in price over the calendar year was similar for the majority of nodes, with over 80% of relevant nodes recording standard deviations of between $10 and $20/MWh. However, in calendar years 2000 and 2001 the level of variation in price over the year is higher and varies considerably from node to node. Certain nodes experienced very high levels of day-to-day price variability in 2000 and 2001.

This measure illustrates that, in addition to the increasing price separation between nodes, there has also been a substantial increase in the day-to-day variability of prices at each node. This combination of increasing inter-nodal and within-node price variability represents a major risk management challenge for market participants – particularly those without appropriately located generation assets.

**Chart 5.2 – Distribution of within-node price deviation**



### $ Cost Measure of Price Risk for an Unhedged Retailer

The '$ cost measure' is an alternative volatility measure expressing volatility in dollar terms. This statistic has been calculated based on the following scenario:

- A hypothetical retailer has a national portfolio (i.e. retails at each node with retail customers);
- The retailer charges the national average (load-weighted) spot price at each node;
- The retailer purchases its energy requirements for each node on the spot market;
- Transmission, distribution and other costs are ignored; and
- The profit / loss at each node in each year since 1996 is calculated using actual spot market prices.

We have identified nodes where:

- the loss from providing a fixed energy cost (equal to the national average energy cost) is greater than 30% of the energy-only tariff revenue; and
- the dollar loss incurred in meeting the load requirement at the node would have exceeded $200,000 (to remove nodes with low load requirements from the analysis).

Taking 2000 as a sample year to avoid the distortion of the atypical weather conditions in 2001, there were 6 nodes that met the criteria specified above. Losses at the 6 nodes ranged from 35% to 61% of notional revenue. This would be equivalent to many years' retail margin.

The difference between the pool price at particular nodes and the national average price is affected by losses and the load profile at each node[13]. However these statistics illustrate the risks associated with hedging at nodes other than where load is located. They also

[13] In the case of the 6 nodes highlighted, average annual price at the nodes exceeded the national average price by between 1% and 21% in the 3 years prior to 2000. This indicates that prices at these nodes are typically higher than the national average - probably due to the effects of losses.

provide a measure of the difficulty of effective national retail competition without access to a diversified national generation portfolio whether achieved via physical assets or financial contracts.

## 5.3 Conclusions

The analysis described in section 5.2 suggests that the price risks faced by participants in the NZEM are considerable. Based on comments made by market participants during our consultations, a number of participants do not believe there is sufficient liquidity in the hedge market to enable efficient risk management.

The liquidity of the contract market is affected by a number of factors unrelated to FNP but, as discussed in relation to efficient investment in new generation, we believe that FNP also contributes to the lack of contract market liquidity. The combination of FNP in the spot market and illiquid hedge markets exposes market participants to electricity price risks, and in particular exposes participants to inter-nodal price variations that cannot be hedged effectively in the current market.

### Key Issues Affecting Outcomes

#### Inter-Nodal 'Basis Risk'

The inability of participants to hedge load requirements at particular nodes exposes them to basis risk when they use contracts available at other nodes to cover their price exposure. This basis risk can be considerable when load is located at a node prone to transmission constraints. In the situation when extreme price outcomes arise at particular nodes as a result of transmission congestion there may be only one generator downstream of the constraint that can supply energy at that node. Arguably, it is not in the interest of the generator that holds intermittent market power at the node to offer hedge contracts based on production costs when the possibility of extracting higher spot market prices exists.

Other generators cannot physically cover hedge contracts offered to load at the affected node. Therefore the risk premium included in their contract offers is likely to be prohibitive. Basis risk at particular nodes is effectively unmanageable in the current market.

### Price Signals and Unmanageable Risks

When the cost of energy at a particular node is influenced by a local generator with intermittent market power the benefits of accurate price signalling are questionable. Electricity users are exposed to price risks that cannot be hedged at costs consistent with production costs and their ability to respond to high prices is restricted by the factors inhibiting demand-side response generally (discussed in section 3.3).

Load location is influenced by many factors other than electricity prices. These include proximity to raw material, transport infrastructure or markets for the firm's output. In many cases decisions on plant location were made well in advance of the implementation of FNP. Therefore, for many industrial loads, variations in electricity input prices at constrained nodes represent an unpredictable input cost that cannot be managed effectively rather than a signal to address problems with electricity supply at particular plant locations.

### Financial Transmission Rights (FTRs)

Prior to the commencement of the market the DRWG anticipated the increase in the degree and rate of variation of prices between nodes that has resulted from the move to FNP, but suggested that this risk could be managed by combining energy contracts with transmission hedges.[14] Transmission hedges have not emerged to date but Transpower's FTR proposal aims to address this shortcoming. The final design of the FTR market had not been agreed at the time of preparing this report. For this reason our comments address generic issues affecting FTR markets.

Proponents argue that the introduction of FTRs would represent a significant addition to the range of instruments available to manage price risk in the NZEM and that FTRs would also improve the incentives for private investment in the transmission system[15]. In our view an FTR market may prove to be less effective in New Zealand than proponents would hope. In particular the lack of liquidity in contract markets for energy hedges is likely to have a negative impact on the demand for transmission hedges. A retailer or major electricity user intending to use an FTR to hedge inter-nodal price differences firstly has to secure an energy hedge contract for their load requirements. If energy hedge contracts are not available at an acceptable price then the demand for FTRs will be restricted.

[14] 'Nodal Pricing in the Wholesale Electricity Market' – page 15

[15] An FTR provides a mechanism for investors to protect their access to cheaper imported power up to the augmented line capacity.

If potential counterparties for transmission hedge contracts have secured energy hedges they may still be reluctant to enter into regular FTR auctions for a number of reasons; including:

- Major users for whom electricity trading is not a core function are at an informational disadvantage compared to generators or retailers with deep market expertise when determining the appropriate price to pay for FTRs.
- The ability of generators to influence the level of L&CS and hence FTR proceeds may deter other users from bidding for FTRs between affected nodes.[16]
- FTRs do not provide a certain hedge against inter-nodal price differences. The 'firmness' of the hedge is dependent on, among other things, the actual flows on the lines between the nodes. Therefore, if an interconnection between two nodes is operating below its notional capacity and FTRs have been allocated based on the full notional capacity of the link, each FTR will entitle the holder to less than 100% of the price differences between the nodes.

### Collection and Subsequent Allocation of Loss and Constraint Settlement Surpluses (L&CS)

The current approach of allocating settlement surpluses to lines companies to distribute (or retain) at their discretion is regarded as being unsatisfactory by almost all market participants we interviewed. Better methods of allocating these surpluses have been the subject of a number of reports and considerable industry debate. An FTR market provides a mechanism for the economically efficient allocation of L&CS. However, the resulting issue of how to allocate auction proceeds presents problems similar to those associated with allocating L&CS.

The collection of L&CS is essentially an administrative issue. In our opinion the current procedures for collecting L&CS do not need to be amended to improve market outcomes.

[16] This concern was identified in the EGR Consulting report 'Financial Transmission Rights for New Zealand: Issues and Alternatives' (8 May 2002). It has been addressed in the draft policy statement on FTRs issued recently by Government by including a requirement to offer long-term allocations of FTRs to some or all of Transpower's offtake customers. Potential bidders will need to be satisfied that the eventual product design provides effective protection from abuses of market power.

The debate on the collection and allocation of L&CS has advanced considerably since we consulted with market participants at the outset of this study. The process has led to the draft policy statement on FTRs issued recently by Government[17]. The policy statement incorporates the key recommendations of the EGR Consulting report on FTRs[18]. Our report does not address the issues associated with the allocation of L&CS and FTRs in the same level of detail as the EGR Consulting report.

During our consultations a number of market participants proposed allocating L&CS to end-users who had contributed to that surplus without establishing an FTR market. Various allocation bases were proposed to apply separately to the return of loss surpluses and constraint surpluses to end-users.

This concept has been incorporated in EGR Consulting's 'regionalised rental rebate' recommendation. Within an FTR framework these rebates would take the form of long-term FTRs allocated to lines companies and end-users. Similarly, the proceeds of auctioned FTRs would be rebated to lines companies and end-users on a regionalised basis. In principle the rebates to end-users should offset the charges those end-users pay for recovery of sunk costs of the grid. Therefore the optimum pass-through mechanism is heavily influenced by the charging basis adopted by Transpower and the way these charges are ultimately reflected in end-users' electricity bills.

Any allocation basis that returns L&CS to loads broadly in line with each load's share of the region's charge for sunk costs should be reasonable. Allocation bases that minimise the distortion to marginal price signals are clearly desirable, but this requirement needs to be balanced against the complexity of implementing the approach. Arguably, a transparent allocation basis that is practical to implement would be preferable to a distortion-minimising basis that is complex to implement. It is also important that the prescribed allocation basis is applied consistently across all regions.

A 'regionalised rental rebate' system that applied to all regions should substantially reduce the risk associated with inter-nodal price variations for retailers[19] and major users without establishing a market for FTRs. For the reasons outlined in the previous section

[17] Supplementary Government Policy Statement on Electricity Financial Transmission Rights, Draft as at 6 August 2002

[18] Financial Transmission Rights for New Zealand: Issues and Alternatives, 8 May 2002

[19] Assuming retailers are allocated the rebates payable to their customers in a particular region (for the period the customer remains with each retailer).

dealing with FTRs, we are not convinced that FTRs would provide significant incremental risk management benefits over those offered by a rental rebate system that returns L&CS to loads broadly in line with each load's share of the region's charge for sunk costs.

### The Underlying Issue

Transmission constraints are the primary cause of major price separation events. It is not practical or economically efficient to build a constraint-free transmission grid, so the problem of markets with few participants is likely to continue at particular nodes. The issues associated with efficient investment in New Zealand's transmission grid and our proposed improvements to current arrangements have been discussed in section 2 of this report.

# 6 Effective Retail Competition

## 6.1 What Outcomes were Expected?

The competitive electricity market was expected to support effective national retail competition.

## 6.2 Assessment of whether Expected Outcomes were Achieved

To assess the influence of FNP on retail competition we need to answer the following questions:

- Can a retailer enter the market and compete effectively at any node?
- If not, is the FNP market model a significant restricting factor?
- Is the current regional structure of electricity retailing attributable to FNP?

### Data Analysis

The presence of effective retail competition is related to the ability of participants to manage the price risks inherent in a FNP market model. Therefore information provided by a statistic like the '$ cost measure' analysed in section 5.2 is a useful indicator of the costs of entering the market as an unhedged retailer.

We have also performed an analysis of market participants' generation and load volumes over the month April 2002 to assess whether there is evidence of strong correlation between the market share of the generation and retail arms of vertically integrated companies in different regions of the country. Our approach to this analysis has been:

- Allocate each node between 3 regions (Upper and Lower North Island and South Island);
- Calculate the market share of generators and retailers in each region over the month April 2002; and
- Measure the correlation between generation output and retail load of vertically integrated companies in each region.

Table 6.1 shows the correlation statistics for April 2002. The split of generation and load volumes between regions for the same period is set out in Table 6.2.

**Table 6.1 – April 2002 Generation/Retail Correlation Statistics**

| | Upper North Island | Lower North Island | South Island |
|---|---|---|---|
| Generation/Retail Load Correlation | 74% | 26% | 89% |

**Table 6.2 – April 2002 Distribution of Generation and Load Volumes by Region**

| | Upper North Island | Lower North Island | South Island | Total |
|---|---|---|---|---|
| Generation | 52% | 11% | 37% | 100% |
| Retail Load | 51% | 18% | 31% | 100% |

The analysis shows a high correlation between generation output and retail load of vertically integrated companies in both the Upper North Island and the South Island. The correlation is not as strong in the Lower North Island but the region accounted for just 11% of the generation sent out in April 2002[20].

The analysis is based on April 2002 data only[21] but provides a useful indication of the extent to which retailers' load is aligned with the location of the companies' generation assets.

[20] The Lower North Island region also had the greatest imbalance between load and generation in the period.

[21] This was the most recent data available to us - we would expect the correlations to vary over the calendar year due to changing generation and load profiles. However, we would not expect this to have a significant impact on the correlation statistics.

## 6.3 Conclusions

The analysis presented above indicates that the retail market is substantially regionalised at present. This conclusion is generally accepted within the industry. The perceived benefits of aligning a company's retail customers with the location of their generation assets in the current market is highlighted by the recent customer swap between Trustpower and Mighty River Power.

There are many factors unrelated to the pricing regime that contribute to the current regionalised structure of the market. In particular, prior to the separation of lines businesses and retail businesses in April 1998 the retail market was effectively structured on an entirely regional basis. Other factors unrelated to FNP influencing a regionalised retail market include transaction costs involved in dealing with different lines companies in different geographic locations and the cost of building retail brands in many regions.

However, to the extent that FNP reduces liquidity in the contract market[22], it is also an impediment to effective national retail competition. In the current retail environment customers have not shown willingness to accept volatility in their electricity costs. This is likely to continue while customers do not have the capability or incentive to respond to wholesale price signals. At present a retailer effectively provides a load-following hedge to their customers by fixing unit prices in advance (typically a year in advance) for their customers' variable electricity usage. A retailer providing this form of contract to customers needs to manage the risks associated with providing this product by reinsuring its risk.

If the retailer also controls generation assets that can meet its load requirements this provides an effective hedge for the price and volume risks associated with the company's retail customers. In a competitive market a stand-alone or new-entrant retailer should be able to approximate the physical hedge provided by vertical integration with a combination of financial contracts. As discussed in section 5, owing to a lack of liquidity the financial contracts market does not currently provide participants with this flexibility. In particular the difficulties in hedging at certain nodes restrict the number of retailers willing to compete for customers at those nodes.

In a market where the costs associated with nodal price spikes are significant and cannot be hedged effectively, then an alternative pricing regime with fewer nodes (i.e. 'zonal pricing') could be expected to channel the availability of contracts to fewer nodal contract markets. The consequent reduction in price volatility and improvement in contract market liquidity should facilitate more effective

[22] The effect of FNP on contract market liquidity is discussed in detail in section 4.3 of this report.

national retail competition. It is our view that in the absence of investment to reduce financially significant transmission constraints, and without greater demand-side response to price signals, the FNP regime will be less effective in facilitating national retail competition than a pricing regime based on fewer nodes. However, in view of the current industry structure (primarily the extent of vertical integration), the benefits of adopting a pricing regime based on fewer nodes may not be material.

# 7 Competitive Price Discovery

## 7.1 What Outcomes were Expected?

The FNP model was expected to discover the true value of energy at each node of the transmission grid through competitive interaction between buyers and sellers. FNP was also expected to limit market power by providing public information on the price of energy, losses and congestion at each node.

## 7.2 Assessment of whether Expected Outcomes were Achieved

To assess whether FNP has provided competitive prices we need to answer the following questions:

- Have market price outcomes at each node been consistent with competitive prices?
- Do buyers have the same information as sellers to determine the drivers of price?
- Is the absence of real-time pricing a major shortcoming?

### Data Analysis

In the absence of information on contract market outcomes our investigation of whether the FNP model has achieved competitive price discovery has been restricted to an analysis of spot price outcomes.

#### Level of Spot Prices

We have analysed the time series of spot price outcomes and investigated high price outcomes in each full year since the commencement of the market as follows:

- Define 'high price days' as those where the (load-weighted) daily price at a given node was greater than twice the (load-weighted) average annual price for that node;
- Identify nodes for which these high price days were 'financially significant' by selecting nodes where the cost of energy purchased on high price days exceeded 10% of the total cost of energy purchases at the node over the relevant calendar year; and
- Assume that all energy purchases are made at the spot market price.

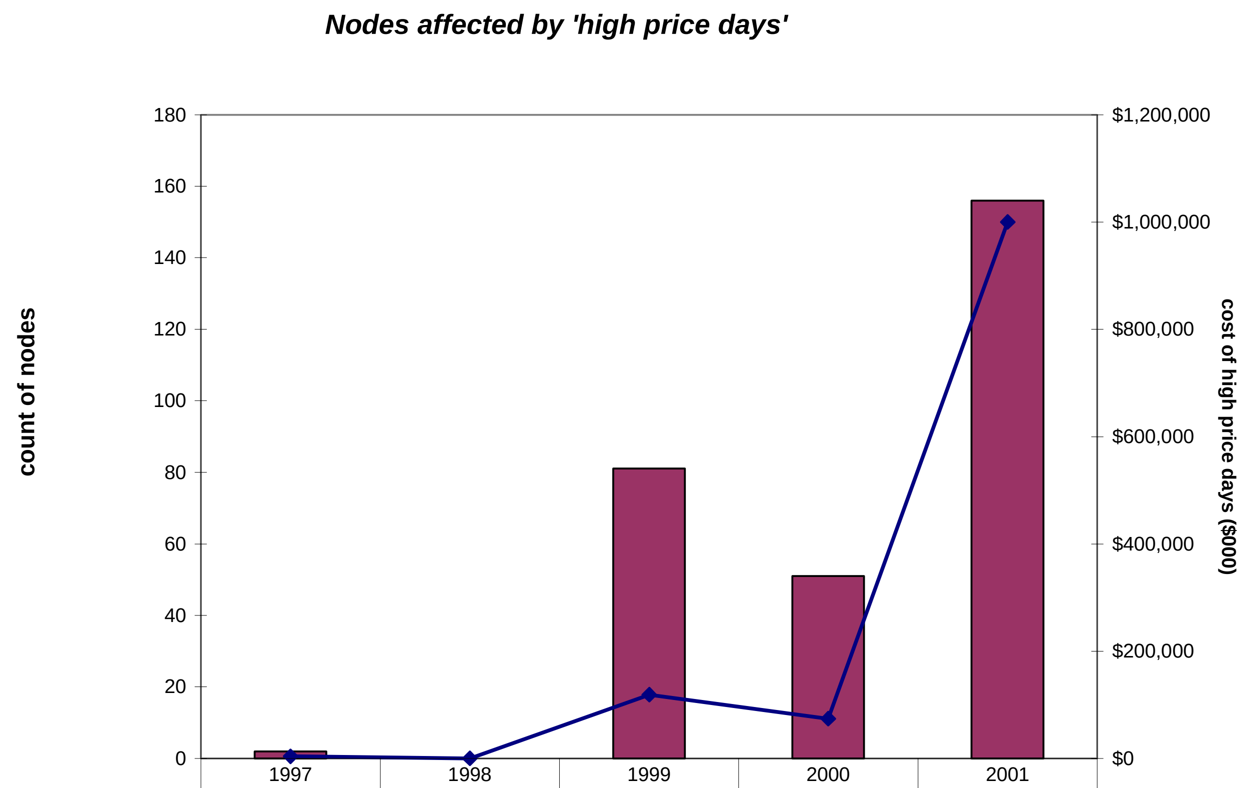
We filtered the results by removing nodes where the total cost of spot market energy purchases over the year was less than $1,000,000.

The final results are summarised in the following chart. The chart illustrates the step increase since 1999 in the number of nodes experiencing high price days that cumulatively accounted for more than 10% of the annual cost of energy at the node.

Only two nodes experienced 'financially significant high price days' over the first two full years of the market. However, the number of nodes affected by these high price outcomes increased to 81 in 1999 and 51 in 2000. The subsequent step increase in 2001 is influenced by the effects of the cold, dry winter conditions in that year. It is notable that, of the 51 nodes experiencing 'financially significant high price days' in calendar year 2000, 43 (84% of these nodes) also experienced 'financially significant high price days' in 1999 and 2001.

While this analysis does not provide an insight into the drivers of high price outcomes observed over the years 1997 to 2001 it does illustrate that high price events would have imposed substantial costs on unhedged load located at the affected nodes since 1998.

**Chart 7.1 – Impact of Financially Significant 'High Price Days'**




| | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|
| count of high price nodes | 2 | 0 | 81 | 51 | 156 |
| cost of high price days ($000) | $3,907 | $0 | $118,596 | $74,355 | $1,000,254 |

## 7.3 Conclusions

FNP does not cause the price spikes that occur at nodes affected by transmission constraints. When prices at a particular node rise relative to prices elsewhere on the grid following a transmission constraint, this typically reflects the higher cost of using local generation to meet demand at the node. In this case, it is the inability of the transmission network to transmit cheaper power, rather than the pricing regime, that causes price separation events. FNP provides the clearest signal to market participants of the impact of transmission constraints (and losses) on the cost of supplying electricity at each point on the grid.

Prices will reflect the true value of energy at each node if market prices are determined by the competitive interaction of suppliers and buyers. The exercise of market power by generators or the inability of demand-side participants to respond to price changes will cause nodal prices to diverge from the true value of energy at affected nodes.

The expectation that prices would be discovered at each node by the competitive interaction of buyers and sellers has not been achieved at all times. When a transmission constraint occurs and it is not possible to import power to a particular node then a local generator may be the sole supplier at that node. The lack of effective real-time demand-side response to price signals adds to the potential for non-competitive price outcomes. In these situations a decision by the generator not to exercise its temporary market power is the only protection against non-competitive price outcomes. FNP should help to restrain the exercise of market power by providing node-specific information on the price of electricity. Information on high price outcomes at specific nodes would be more obvious to market participants and end-users under FNP than under alternative pricing regimes based on fewer nodes and greater socialisation of costs.

From the perspective of price-signalling and public information, the benefits of charging users the prices discovered at each node should be balanced against the economic impact of high nodal prices on users who lack the practical means to respond to those prices. If, for example, a major user faces high nodal prices as a result of transmission constraints caused by changing power flow patterns over the whole network, it is not clear that the user should be required to bear the full cost of the reduced ability of the network to transmit cheap electricity to their node to achieve efficiency or equity objectives of the market. The equity of this cost allocation is particularly questionable if the major user’s locational decision was made many years before FNP was introduced and/or before transmission constraints started to affect the cost of supplying electricity at the user’s node. If high price outcomes are the result of generators exercising market power, then the costs borne by customers at affected nodes appear to be even less equitable.

A pricing regime based on fewer nodes (and therefore with socialisation of costs), combined with monitoring of extreme nodal price outcomes may be a more appropriate framework in a market where individual nodes are subject to price shocks due to changing power flows on the interconnected grid.

# 8 Conclusions

This section summarises the key conclusions of the 5 sections comparing expected market outcomes with those actually achieved since the market commenced in 1996. The summary concentrates on the influence of FNP on the observed outcomes.

## 8.1 Summary of Conclusions on the 5 Expected Outcomes

### Efficient Short-Run Operation

- FNP has achieved the efficient dispatch objectives of the market to the extent that market prices are determined by the competitive interaction of suppliers and buyers.
- The marginal loss pricing model adopted in the NZEM is consistent with efficient short-run operation of the market.
- Nodal prices signal the cost of electricity consumption with more accuracy than any other pricing regime but the benefit in terms of short-run demand-side participation in the electricity market is restricted by various impediments.
- Transpower's current transmission pricing methodology recognises the trade-off between the distortion to short-run efficient usage of the grid and the distortion to long-term efficient usage of the grid.
- Predictable grid operation practices are key to achieving efficient short-run operation of the electricity system by enabling lower cost dispatch through flexible grid operation and making FNP signals more predictable.

## Efficient Long-Run Operation

- The location of new investment in generation capacity since 1996 appears to have been influenced by FNP – the main generation investments have been located close to Auckland.
- The influence of the FNP regime on the timing of new investment is less clear.
- There has not been major new investment to relieve transmission constraints despite a pronounced increase in inter-nodal price volatility over the period.
- There has been little evidence of significant demand-side response to nodal pricing signals.
- We believe that FNP contributes to the lack of contract market liquidity. A lack of contract market liquidity represents a barrier to investment by new entrant generators.

## Ability to Manage Risk

- FNP contributes to the lack of effective hedging alternatives to appropriately located physical generation. However, the high level of vertical integration in the industry is believed to be a major adverse influence on the availability of hedge contracts in the electricity market.
- The 'basis risk' associated with hedging load requirements at particular nodes is effectively unmanageable in the current market.
- Although FTRs will improve the ability of market participants to manage electricity price risk, in our view an FTR market may prove to be less effective than proponents would hope.
- Efficient investment in the transmission grid should result in fewer nodal price separation events and hence reduce the risks associated with inter-nodal trade.

## Effective Retail Competition

- The retail market is substantially regionalised at present. To the extent that FNP reduces liquidity in the contract market it is also an impediment to retail competition on a national basis.
- Improvements to the allocation of L&CS and any other steps that enhance the ability of market participants to manage risk in the NZEM can be expected to have a beneficial effect on retail competition.
- In the absence of investment to reduce financially significant transmission constraints, and without greater demand-side response to price signals, the FNP regime appears to be less effective in facilitating national retail competition than a pricing regime based on fewer nodes.

## Competitive Price Discovery

- FNP does not cause the high price spikes that occur at nodes affected by transmission constraints.
- Information on high price outcomes at specific nodes will be clearer to market participants and end-users under FNP than under alternative pricing regimes based on fewer nodes and greater socialisation of costs.
- The expectation that prices would be discovered at each node by the competitive interaction of buyers and sellers has not been achieved when transmission constraints prevent load at particular nodes from importing cheaper power. The lack of effective real-time demand-side response to spot market price signals adds to the potential for non-competitive price outcomes.
- The economic impacts of high nodal prices on users who lack practical means to respond to those prices can be severe.

## 8.2 Significant Benefits of FNP

### Efficient Dispatch

FNP is the pricing regime that is most consistent with the efficient dispatch of generation (or load) to meet changes in load at each node.

### Efficient Price Signals

The FNP regime provides valuable information on the cost of meeting load at each exit point on the transmission grid. This price signalling facilitates efficient planning of new investment in electricity infrastructure. The node-specific nature of FNP signals means that these signals are more transparent than under alternative pricing regimes involving some form of aggregation of nodes for pricing and settlement.

## 8.3 Most significant shortcomings

### Forum to Assess and Direct Transmission Investment

We have discussed various factors hindering effective response to the efficient price signals provided by FNP in this report. In our opinion FNP signals are not sufficient to stimulate new investment in the transmission grid, given the other factors that deter private investment. A planning forum to assess the market-wide and economy-wide benefits of investment in the electricity network should result in more efficient investment decision making and more efficient long-run system operation.

### Lack of Liquidity in Contract Markets

In our view FNP contributes to the lack of liquidity in nodal forward markets. Lack of liquidity in the hedge markets is a significant obstacle to efficient risk management for many market participants and presents a barrier to investment by new entrant generators.

However the high level of vertical integration in the industry would limit the potential improvement in contract market liquidity that could be achieved by adopting a pricing regime based on fewer nodes.

### Inter-Nodal 'Basis Risk'

The inability of market participants to hedge load requirements at particular nodes exposes them to basis risk when they use contracts available at other nodes to cover their price exposure. Basis risk at particular nodes is effectively unmanageable in the current market.

### Burden/Allocation of Extreme Price Outcomes

From the perspective of price-signalling and public information, the benefits of charging users the prices discovered at each node need to be balanced against the economic impact of high nodal prices on users who lack the practical means to respond to those prices. The benefits of FNP to the economy as a whole should take account of the costs associated with the increase in the degree and rate of variation of prices between nodes associated with FNP as well as the benefits of efficient signalling for investment in New Zealand's electricity infrastructure.

## 8.4 Overall Conclusion

Our analysis of the available information on market outcomes since 1996 has not identified strong evidence to date of significant benefits related to the accurate signalling properties of FNP. However, there is evidence of a pronounced increase in price separation between nodes and day-to-day price variations at individual nodes.

Where market outcomes that the FNP model was expected to achieve have not emerged, the causes of failure can, in many cases, be attributed to impediments unrelated to market design. Our report discusses the influence of a number of these impediments on market outcomes.

A pricing regime based on fewer 'representative' nodes (a zonal model) appears to offer benefits from risk management and retail competition perspectives. However a zonal model would distort the investment incentives provided by the FNP model. Some market participants also expressed concern about potential gaming opportunities associated with the rules necessary to implement a zonal pricing model.

Evaluating the relative merits of alternative market design options is critically dependent on the relative weightings attributed to economic efficiency and equity criteria. A further pre-requisite for any evaluation of alternative market design options would be to agree a definition of the equity objectives of the market.

Any proposal to change the market design needs to take account of the current industry structure and recent developments aimed at addressing important shortcomings in the current market. These include provisions to establish a consultative forum to address problems associated with transmission investment[23] and the ongoing development of a transmission hedging instrument to address problems associated with inter-nodal price differences.

[23] Part F of the proposed Rule Book governing New Zealand's electricity arrangements

# Part III Appendices

## A List of Interviewees

| Company | Interviewee |
|---|---|
| Transpower | Doug Goodwin |
| Meridian Energy | Ari Sargent |
| M-co | Ramon Staheli, Philip Bradley |
| Contact Energy | Toby Stevenson, Mark Trigg, Steve Barrett |
| Trustpower | Keith Tempest |
| Genesis Power | Dean Carroll, Wayne Crean |
| Mighty River Power | William Meek |
| Fletcher Building | Alan Beeston |
| Comalco | Jason Franklin |
| Todd Energy | Rodney Deppe, Babu Bahirathan, Charlie Teichert |
| Natural Gas Corporation | Mike Bailey |
| ex EMCO | Lincoln Gould |
| Network Tasman | Colin Starnes |

# B Marginal Losses vs. Average Losses

In this appendix we demonstrate algebraically why marginal loss pricing results in a more efficient dispatch than average loss pricing when losses (rather than constraints) limit the dispatch of distant generation. The scenario illustrated assumes that a generator located at a distant node and a local generator are competing to meet load at a particular node. The distant generator's unit cost of production is lower than the local generator's.

Definition of terms:

| | |
|---|---|
| $P_D$ | Price (per MWh) of distant generation |
| $P_L$ | Price (per MWh) of local generation |
| a | Loss coefficient (constant) for power transmitted from distant generator (D) to load at L |
| W | Power received at the load location |
| K | Load requirement at load location |

Assumptions:

Generators' bid prices are constant for all quantities supplied
Generation located at D and L both have installed capacity > K
Zero losses associated with meeting load at L with generation at L

Power losses are proportional to the square of the power flow; resulting in the following equations:
Total Losses (from D to L) = $aW^2$
Average Losses = aW
Marginal Losses = 2aW

$P_D = \$X$
$P_L = \$(X + B); B>0$

| | Cost of meeting load requirement of W at location L | |
|---|---|---|
| **Generation location** | **Marginal Loss Pricing** | **Average Loss Pricing** |
| D (distant) | $XW(1+2aW) | $XW(1+aW) |
| L (local) | $(X+B)W | $(X+B)W |

Therefore, supply will be dispatched from D until:

<u>Average Loss Pricing</u>
$\$X(1+aW) >= \$(X+B)$

$\Rightarrow$ until $W = B / Xa$

<u>Marginal Loss Pricing</u>
$\$X(1+2aW) >= \$(X+B)$

$\Rightarrow$ until $W = B / 2Xa$

Therefore, where loss limits the dispatch of distant generation, the supply (W) from distant generation based on average loss pricing will be up to double that supplied based on marginal loss pricing.

The total cost of meeting load at L from generators located at L and D will also be higher using average loss pricing:

<u>Average Loss Basis:</u>

Total Cost $= \$X(B / Xa) + X(a(B / Xa)^2) + \$(X+B)(K-(B / Xa))$

$= \$(X+B)K$

<u>Marginal Loss Basis:</u>

Total Cost $= \$X(B / 2Xa) + X(a.(B / 2Xa)^2) + \$(X+B)(K-(B / 2Xa))$

$= \$(X+B)K - \$(B^2 / 2Xa) / 2$

$\Rightarrow$ Extra cost of meeting load at L using average loss pricing rather than marginal loss pricing $= \$(B^2 / 4Xa)$

# C Inter-Nodal Price Volatility Statistic

To assess the level and variability of inter-nodal price differences we have studied the development of the following statistic over time:

$$D_{y,d} = \sqrt{\sum_{i=1}^{all\ nodes}\left(\left(p_{i,d} - \overline{p}_d\right)^2 \times l_{i,d} \Big/ \sum_{i=1}^{all\ nodes} l_{i,d}\right)}$$

where:

$D_{y,d}$ = Inter-nodal price volatility statistic for day d
$p_{i,d}$ = Load-weighted price for node i on day d
$\overline{p}_d$ = Load-weighted average national price for day d
$l_{i,d}$ = Demand (in MWh) at node i on day d

This statistic measures the standard deviation of daily nodal prices from the national (load-weighted) average price for the day. Individual deviations from the mean are weighted by the ratio of load at that node to total national load for the day. The resulting values provide a measure of the level of inter-nodal price differences for each day in \$/MWh terms.