

ELECTRICITY COMMISSION

Consultation Paper

Options for Enabling Transmission Alternatives

31 May 2005

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	4
2. INTRODUCTION	13
2.1 Background.....	13
2.2 Purpose of this Paper	13
2.3 Submissions.....	13
2.4 Commonly Used Abbreviations	14
2.5 General Approach and Overview of the Paper	15
2.6 Types of TAs	16
2.7 Regulatory Environment	18
2.8 Existing TAs.....	19
3. OPTIONS FOR TRANSMISSION ALTERNATIVES.....	21
3.1 Problem Definition	21
3.2 Design Principles for TA Procurement	22
3.3 Central Procurement Agency.....	23
3.4 Option 1: Market Response Investment in TAs	24
3.5 Option 2: Universal Central Procurement (universal CP).....	26
3.6 Option 3: Minimal Central Procurement (minimal CP)	27
3.7 Option 4: Limited Decentralised Procurement (limited DP)	29
3.8 Option 5: Regional Capacity Contracts (RCC).....	30
3.9 Other Options	32
4. ECONOMIC AND REGULATORY ARGUMENTS.....	34
4.1 Introduction.....	34
4.2 Investment Certainty and Commitment	34
4.3 Free Riding on Transmission Charges	35
4.4 Free Riding on Nodal Prices.....	37
4.5 Other Nodal Pricing Deficiencies.....	37

4.6	‘Slippery Slope’ Risks	42
4.7	Summary of Issues	43
5.	EVALUATION OF OPTIONS	44
5.1	Evaluation Criteria	44
5.2	Evaluation against Criteria	44
5.3	Cost-Benefit Assessment	49
5.4	Assessment against Commission’s Objectives and GPS Outcomes	53
	APPENDIX 1: GRID INVESTMENT PROCESS OVERVIEW	57
	APPENDIX 2: OPERATIONAL CONSTRAINTS FOR THE CP OPTIONS	58
	APPENDIX 3: TESTS FOR THE MINIMAL CP OPTION.....	71
	APPENDIX 4: REVIEW OF THE RCC OPTION	75
	APPENDIX 5: LIST OF CONSULTATION QUESTIONS.....	82
	APPENDIX 6: FORMAT FOR SUBMISSIONS	84

1. Executive Summary

Introduction

1. One of the key changes in introducing the Electricity Governance Rules 2003 (the Rules) was the move to a regulated decision making process for transmission investments. Previously, Transpower New Zealand Limited (Transpower) directly contracted with transmission users for investment,¹ now, the Electricity Commission (the Commission) approves or declines grid investment proposals from Transpower. If the Commission approves an investment then Transpower has the regulated ability to recover the cost of that investment.
2. A key balance to the regulatory grid investment process is the requirement to consider transmission alternatives (TAs), via the Grid Investment Test (GIT). Rule 2.2 of section III of part F of the Rules, for example, states that a purpose of section III is to assist participants to identify and evaluate investments in TAs. Importantly, there is no explicit provision in the Rules for the TAs to be procured or to be funded.

Purpose of this paper

3. The Government Policy Statement on Electricity Governance (the GPS) requires the Commission to “consider whether there would be net benefits in providing for a mechanism whereby investments in transmission alternatives receive payments reflecting some or all of the value of avoided transmission investment” (paragraph 90). This paper specifically advances this policy requirement.
4. The purpose of this paper is to establish the Commission’s high-level policy direction regarding enabling TAs. The paper analyses the options for facilitating TA investment and seeks submissions from interested parties. The paper takes a broader approach than signalled in the GPS, as it considers not just mechanisms for paying for TAs but also decentralised options that may facilitate efficient decision-making between grid expansion and TA investment. These options are evaluated against a counterfactual where TAs are not enabled.

Background

5. A TA is generation, load, or a network arrangement that reduces demand for transmission, and so allows grid investment to be deferred or avoided.
6. The Rules require the Commission to use the GIT to determine the net market benefits of investments in transmission assets and TAs, and determine which is the most appropriate choice in each location, taking into consideration grid reliability standards.
7. In particular, rules 9.1.2 and 11.2 of section III of part F require the Commission to consider TAs in preparing statements of opportunities (SOOs) and the centralised data set (CDS), and rule 6.2 requires the Commission to use the GIT to review TAs. Rule 13.3.3.4 of section III of part F empowers the Commission to ask Transpower, where Transpower possesses the relevant expertise, to evaluate TAs, and rule 14.3.2.2 empowers the Commission to direct Transpower to investigate and apply the GIT to TAs.
8. A key issue in achieving the right balance between grid and TA investment revolves around the view that a constraint-free grid is necessary to have a competitive electricity market. This implies transmission should be built even

¹ In practice little investment in the interconnected network occurred under this approach.

if a TA produces larger net market benefits. The GIT addresses this issue because it includes "competition benefits," which allows the competitive benefits of removing constraints to be taken into account in the analysis of transmission versus TA investment.²

Problem definition

9. Many grid investments are reliability investments, which are needed to reduce the risk of supply interruptions.³ As TA investments may be used to substitute for grid reliability investments, the Commission needs sufficient confidence they will occur within timeframes needed to achieve reliability requirements.
10. In applying the GIT the Commission is faced with the prospect of comparing Transpower's proposals against TA investments that typically require much shorter lead times, and will therefore not be scheduled to occur until after it is too late to make grid investments to address reliability risks. In this situation the Commission is unlikely to defer or reject inefficient grid upgrade plans without a reasonable degree of certainty that TA investments will occur within required timeframes.⁴
11. Historically, TAs have emerged in a number of locations based on local requirements. It is possible that some TAs may not have emerged because of:
 - a. *Free rider problems*: all consumers in a region benefit from the actions of other consumers or local generators who reduce demand for transmission and thereby reduce nodal prices and transmission charges for all consumers;⁵ and
 - b. *Commitment problems*: TA providers, particularly generators, are less likely to commit to large sunk investments if Transpower can strand their investment by subsequently undertaking its own investments and recovering costs through regulated means.
12. The Rules seek to address the commitment problems by providing transparent processes for identifying opportunities for investment and by adopting transparent methods for determining when grid investment is the best solution for New Zealand. These objectives are intended to be achieved through regular publications of SOOs, and rigorous and consistent application of the GIT to Transpower's grid upgrade plans and to TAs.

Objectives, design principles, and evaluation criteria

13. Consistent with the Commission's principal objectives and the specific outcomes required of it, pursuant to the Electricity Amendment Act 2004, the Commission believes the objectives of any arrangement to facilitate TA investment should be to:
 - a. Achieve a lower total cost of delivered electricity by ensuring TA investments occur when they are cheaper than grid reliability investments;

² Note: The GIT assesses the net economic benefits of grid and TA investment proposals, so that wealth transfers arising from grid reinforcement are not counted as net market benefits.

³ "Reliability investments" are defined in part A of the Rules as "investments ... the primary effect of which is, or would be, to reduce expected unserved energy."

⁴ Of course there is always uncertainty with any large investment, including for grid investments, but the uncertainty with respect to TA investments is far greater if the Commission is relying entirely on market responses occurring as compared to approving regulated grid investments.

⁵ In theory, the free rider problem should not constrain investment by generators as they are able to capture benefits from rising nodal prices at times of transmission constraint. However, under a postage stamp transmission charging methodology, generators are unable to capture the full avoided cost of transmission from their investment in TAs.

- b. Achieve reasonable certainty for the Commission that, if it rejects a grid reliability investment on the grounds that TAs are a more efficient option, TAs of appropriate reliability⁶ will eventuate within required timeframes; and
 - c. Minimise risks to the market environment, in terms of the potential for the regime to lead to increasing central planning of the generation sector ('the slippery slope').
14. To assist with achieving these objectives, the Commission believes the following principles should be adopted for designing policies and procedures that enable transmission alternatives:
- a. Promote a level playing field between grid investments and TAs, and between alternative types of TAs, so that the lowest cost options are achieved consistent with grid reliability standards;
 - b. Maximise opportunities for innovation in the provision of TAs to reduce the cost of electricity over the long run;
 - c. Provide reasonable certainty that TA investments will occur within required timeframes (and will operate when required);
 - d. Promote certainty for investment in the grid and investment by grid users;
 - e. Minimise adverse effects on the competitive sectors of the market (i.e. minimise 'slippery slope' risks);
 - f. Be consistent with the GIT and other work streams; and
 - g. Minimise administration and compliance costs.
15. The above objectives and design principles form the criteria for evaluating each of the options. Implementation timeframes are not included in the design principles, as the Commission wishes to identify the best regime for the longer term.

The options

16. This paper considers five broad options for facilitating TAs:
- a. *Option 1: market response.* Under this approach the Commission assists market participants to identify and evaluate investments in TAs,⁷ but relies on investments in TAs occurring in response to market conditions and grid expansion decisions. This is the status quo under the Rules;
 - b. *Option 2: universal central procurement (universal CP).* Under this approach a central body determines the total quantity of TAs to be procured in each region *to meet reliability of supply needs*, and conducts a tender to procure those TAs.⁸ The procurement contracts under this option specify maximum prices that generator TAs are allowed to offer energy into the market, and place other operational constraints on them;
 - c. *Option 3: minimal central procurement (minimal CP).* This approach is similar to option 2, but with no price constraints and fewer operational constraints. It also includes tests to try to avoid funding TAs that would occur in response to market conditions;

⁶ The term "appropriate reliability" is intended to indicate consistency with the grid reliability standards (GRS) and required reliability/cost trade-offs through the GIT.

⁷ As required by rule 2.2 of section III of part F of the Rules.

⁸ Note that the identity of the central body is discussed further in section 3.3.

- d. *Option 4: limited decentralised procurement (limited DP)*. As with the CP approaches (options 2 and 3), a central body determines the total quantity of TAs to be procured in each region *to meet reliability of supply needs*. Rather than conduct tenders, the central body assigns capacity obligations to demand-side entities (DSEs) to procure TAs, based on their share of regional peak demand. Under this option a central body monitors DSEs' compliance with their capacity obligations and verifies that TAs meet reliability requirements. Financial penalties are imposed on DSEs for not meeting their obligations; and
 - e. *Option 5: full decentralised procurement (full DP) or regional capacity contracts (RCC)*. Under this option DSEs, rather than a central body, forecast their own load and pay penalties for failing to meet their capacity obligation and for inaccurately forecasting demand (when compared with real time demand). In contrast to the limited DP approach, the central body would not be able to determine under-performance until real time. This option has been developed by Contact Energy.⁹
17. It is proposed that, if option 2, 3, or 4 is selected, the System Operator undertake the role of central procurement agency. Further discussion on this point is included in section 3.3 of the paper.
 18. It is important to note the Commission is only considering TA arrangements needed to achieve reliability of supply. Although TAs that substitute for grid economic investments may also suffer from the 'free rider' problems discussed above, the Commission does not require the same degree of certainty about them as it does for reliability TAs.
 19. In regard to the DP options, the Commission is considering whether DSEs should be defined as either retailers or line companies (and may also include large directly-connected consumers).

Evaluation of the options

20. The Commission has analysed the CP options, and has reviewed Contact Energy's regional capacity contracts (RCC) option in some detail (see appendix 4). It has undertaken a detailed qualitative evaluation of the options against the principles for designing procurement policies and procedures, and this is contained in section 5.2, and summarised in Tables 1 and 2 (below). These tables should be reviewed in conjunction with section 5.2.
21. A detailed quantitative cost-benefit analysis has not been completed at this stage, though a discussion of the costs and benefits is included in section 5.3.¹⁰ Section 5.4 then assesses the options against the Commission's principal objective and specific outcomes.

⁹ As Contact Energy refers to the option it has developed as regional capacity contracts, the Commission adopts the same terminology when discussing Contact Energy's option specifically. The Commission also refers to it more generally as a DP (decentralised procurement) option. Contact's proposal is detailed in a paper available on its website at: <http://www.mycontact.co.nz/view?page=/forinvestment/publications/governmentsubmissions>.

¹⁰ A cost benefit analysis will be included in the consultation documentation that is published when rule changes are proposed, if they are required.

Table 1: Evaluation of the Options

	<i>Promotes level playing field among TAs & with transmission?</i>	<i>Maximises innovation opportunities?</i>	<i>Promotes TA investment and operational certainty?</i>	<i>Promotes certainty for investment in grid & investment by grid users</i>	<i>Minimises 'slippery slope' risks?</i>	<i>Consistent with the GIT and other work streams?</i>	<i>Low administration and compliance costs?</i>
<i>Market Response</i>	A big "NO", because the option does not address free rider issues	A small "yes" because TA providers are free to contract with whomever they like, but innovation may be undermined by lack of level playing field	A big "NO" as it leaves EC reliant on TAs until after too late for grid investment - likely to seriously undermine Commission's ability to approve anything other than Transpower's GUP	Yes, because this option is simple and can be implemented immediately	A big "YES" because it would probably result in the EC approving grid investment - so no pressure on regulators to intervene in generation investment ¹¹	Yes, because GIT decisions take into account views about market response	Yes, because EC only required to identify and evaluate TAs
<i>Universal CP</i>	A small "yes" because the option addresses free rider issues and provides regulated funding only to the extent needed to meet supply reliability	A small "no" because although TA procurement decisions made by a central body, assistance is limited to that needed for supply reliability. Tenders likely to foster some demand-side innovation	A big "YES" because TAs will be required to sign procurement contracts with liability provisions etc	Neutral, as this option will take some time to develop and implement, but will promote certainty once implemented	A significant "No" because TA contracts include maximum price provisions and other constraints on generator TAs, which undermine market incentives and information	Yes, because GIT can include tender information	No, because significant costs with setting pricing and operational constraints. There are also problems with distinguishing between new, existing, and retiring capacity
<i>Minimal CP</i>	Same for all procurement options – see the text under universal CP	Same as universal CP	Same as universal CP	Same as universal CP	A small "yes", as option provides a sound mechanism for directly addressing free rider problems & tender processes preserve incentives for investment in ordinary generation. Not a big "Yes" as this option, unlike DP, doesn't create a tradable property right, which would provide better quality	Same as universal CP	No, because significant costs with conducting tests

¹¹ Note that the presence of regulated transmission investment means that the market response option is certainly not free of regulatory intervention. The market response option receives a big YES because *in regard to intervention in TAs* it is robust to 'slippery slope' risks.

Table 1: Evaluation of the Options

	<i>Promotes level playing field among TAs & with transmission?</i>	<i>Maximises innovation opportunities?</i>	<i>Promotes TA investment and operational certainty?</i>	<i>Promotes certainty for investment in grid & investment by grid users</i>	<i>Minimises 'slippery slope' risks?</i>	<i>Consistent with the GIT and other work streams?</i>	<i>Low administration and compliance costs?</i>
					information to decision-makers		
<i>Limited DP</i>	Same for all procurement options – see the text under universal CP	A small “yes” because multiple DSEs make TA procurement decisions, but this is limited because volume of capacity obligations limited to that needed to achieve supply reliability	A big “YES” because EC determines and allocates capacity obligations to DSEs sufficient to meet supply reliability	No, as identified complexities mean that this option will take quite some time to develop and implement relative to the non-DP options. Option also has fairly significant implications for DSEs and generators, and may involve complicated compliance regimes.	A significant “Yes” because this option provides a sound mechanism for directly addressing free rider problems, and markets for capacity obligations preserve incentives for investment in ordinary generation and provide regulators with good quality information. Not a big “YES” because option relies on multiple DSEs, with conflicting incentives, to implement the regime. Practical problems may also exist that limit ability to target the intervention to beneficiaries of TA investment	A small “no” because, although GIT decisions can be made on the basis of generic TA types and information from the capacity market, this option is not consistent with the postage stamp approach to grid charges	No because significant costs with setting and allocating capacity obligations and with verifying TA availability and reliability
<i>RCC (or full DP)</i>	Same for all procurement options – see the text under universal CP	Same as limited DP	A small “Yes” because although capacity obligations enhance investment certainty, imposing penalties determined after real-time leaves it too late to organise other TAs if capacity is not available in real-time	Same as limited DP	Same as limited DP	Same as limited DP	No because there are significant costs with setting financial penalties & monitoring security risks. Also, capacity reconciliation issues likely to be very significant

Table 2: Evaluation of the Options - Summary

	Promotes level playing field among TAs, & between TAs and transmission?	Maximises innovation opportunities?	Promotes TA investment and operational certainty?	Promotes certainty for investment in grid & investment by grid users	Minimises 'slippery slope' risks?	Consistent with the GIT and other work streams?	Low administration & compliance costs?	Total score ¹²
Market Response	XX	√	XXX	√	√√√	√	√	2
Universal CP	√	X	√√√	-	XX	√	X	1
Minimal CP	√	X	√√√	-	√	√	X	4
Limited DP	√	√	√√√	X	√√	X	X	4
RCC (or full DP)	√	√	√√	X	√√	X	XX	2

¹² The total score for each row is calculated as total ticks minus total crosses across the columns. The 'slippery slope' risks and 'investment certainty' criteria are weighted more heavily by allowing up to three ticks and three crosses. The other criteria are allowed only two ticks or crosses. A dash means the option is neutral with respect to the criterion.

Q1: Do submitters agree Tables 1 and 2 contain the correct evaluation criteria, and are they weighted appropriately? If not, what criteria and weightings would you use? Do submitters agree the scores in Table 2 accurately reflect the evaluation provided in Table 1 and section 5.2? If not, how would you score the options in Table 2 so that it is consistent with Table 1?¹³

Conclusions

22. The Commission has not developed a clear preference for any of the options at this stage. The high-level qualitative evaluation in section 5.2 suggests that:
- Procurement is likely to have significant net benefits over the market response option, provided 'slippery slope' risks can be managed. It does not, however, provide clear direction in terms of which procurement option should be progressed;
 - All of the procurement options will increase the Commission's confidence that TAs will eventuate in a timely manner if a grid upgrade proposal is rejected. However, the degree of confidence provided varies widely between the procurement options, with the RCC option providing the lowest confidence;
 - The universal CP option has greater 'slippery slope' risks than the options that procure a subset of TAs (such as only demand side TAs, or only those that suffer from the free riding problem);
 - A variant of the minimal CP option, suggested in section 3.9, is not to fund some or all TAs but simply agree commitment contracts with them. Adopting this variant of the minimal CP may provide a lower cost means to address the commitment problem for potential generation investors;
 - The DP options require the allocation of existing transmission capacity and the development of penalty regimes. These and other practical issues would be likely to delay the introduction of a DP option until well after the first major grid upgrade decisions have been made.

Other options

23. There are a number of variants to the above options, discussed in section 3.9 of the paper. Although the Commission has not developed or evaluated these other options, it is interested in hearing submitters' views on them and other options they believe warrant further consideration.
24. For example, the minimal CP option could be made more minimal by not providing any funding for TAs. The rationale for such a change is that generator TAs, in large part, do not suffer free rider problems in regard to nodal pricing, and removing them from the procurement process would go a long way to reducing 'slippery slope' risks. Demand-side TAs may or may not receive funding under such an option.
25. Under this approach – which could be called the "commitment variant of the minimal CP option" – the Commission calls for TAs to contractually commit to build and operate their plant within required timeframes, and approves Transpower's grid upgrade plans if TA commitments are insufficient to delay grid investment.
26. Although this approach has some attraction to the Commission, there are several issues to resolve about the statutory ability of the Commission to implement this approach.

¹³ Note, question 10 asks submitters whether they agree with the evaluation in section 5.2.

Links with other work streams

27. The development of policies and procedures for procuring TAs carries implications for several work streams, particularly transmission pricing, transmission service definitions and benchmark agreements, the development of energy and transmission hedges (e.g. financial transmission rights), and the work streams on electricity efficiency and security of supply. The outcomes of some of these work streams, particularly transmission pricing, also have significant implications for this work.
28. Finally, and perhaps most importantly, the approach to procuring TAs carries potentially significant long-term implications for the role of the wholesale electricity market. These linkages are discussed in section 2.5.2 and will become apparent as the reader progresses through the paper.

Consultation

29. Following receipt of submissions, the Commission will seek cross-submissions, and from this develop and publish a decision document on the high-level approach to TAs.
30. Following this, more detailed specifications of the preferred option will commence and associated rule changes will be developed if these are required.
31. The Commission is now seeking submissions on this paper, including the evaluation of the options, prior to undertaking further work.

2. Introduction

2.1 Background

32. Part F of the Rules requires the Commission and Transpower to consider TAs when evaluating grid investment proposals. However, there is little guidance about how they should do so, as the Rules do not explicitly provide for the procurement of TAs.
33. Paragraph 90 of the GPS requires the Commission to “consider whether there would be net benefits in providing for a mechanism whereby investments in transmission alternatives receive payments reflecting some or all of the value of avoided transmission investment.”
34. The Commission therefore requested that M-co assist it in developing high-level policies and procedures for identifying, evaluating, contracting, procuring, and operating TAs. This follows work undertaken by SAHA International, which prepared a seed paper to initiate and inform discussion on these issues.¹⁴ The Commission has consulted with the Transmission Advisory Group (TAG) in the preparation of this paper. However, the views in this paper do not necessarily represent the opinions of TAG members.
35. In order to consider whether there are net benefits from providing a mechanism to enable TAs, it is necessary for the Commission to identify the range of options for their provision and then consider their merits in relation to continuing with the current settings. There is a continuum of possible options to facilitate TAs. At one end of the continuum the Commission could rely on market response TAs when evaluating Transpower’s grid upgrade plans. At the other end of the continuum, a central procurement agency could procure TAs in the same way as transmission, or it could require other parties to procure TAs. Many intermediate options also exist. To provide some focus this paper identifies and evaluates the main options, and briefly notes (in section 3.9) further sub-options.

2.2 Purpose of this Paper

36. This paper and the submissions received on it will guide the development of the Commission’s policy on TAs. The paper outlines the analysis undertaken on proposals to procure TAs, compared with the market response option. It also outlines the analysis undertaken to inform the debate as to whether such procurement should be centralised or decentralised.
37. In order to facilitate consultation on the approach and proposed design, a number of questions are presented throughout the paper. Following consultation, further work will be undertaken to develop a proposal, including any necessary rule amendment proposals for part F of the Rules.
38. A statement of proposal is not included in this consultation paper, as the Commission has not yet determined a preferred option, so no rule amendments are recommended.

2.3 Submissions

39. The Commission invites submissions on this paper by **5pm on 22 July 2005**. Submissions received after this date may not be able to be considered.

¹⁴ SAHA International, *Alternatives to Investments in the Transmission Grid*, Final Report to the Electricity Commission (2 July 2004). Available at www.electricitycommission.govt.nz.

40. The Commission's preference is to receive submissions in electronic format (Microsoft Word). The electronic version should be emailed, with "Options for Enabling Transmission Alternatives" in the subject header, to info@electricitycommission.govt.nz. Please contact Jenny Walton if you have any questions. Her contact details are as follows:

Jenny Walton
Electricity Commission
Level 7, ASB Tower
2 Hunter Street
P O Box 10041
WELLINGTON
Tel: (04) 460 8860
Fax: (04) 460 8879

The Commission will acknowledge receipt of all submissions electronically. Please contact Jenny Walton if you do not receive electronic acknowledgement of your submission within two business days.

41. Questions are provided throughout the paper, and are listed in appendix 5.
42. Submissions should be provided in the format shown in appendix 6. Submissions are likely to be published on the Commission's website. Submitters should indicate any documents attached in support of the submission in a covering letter, and clearly indicate any information that is provided to the Commission on a confidential basis. All information provided to the Commission is subject to the Official Information Act 1982.

2.4 Commonly Used Abbreviations

Act	The Electricity Act 1992
CDS	Central Data Set
DSE	Demand-Side Entity (retailers or distribution companies)
EECA	Energy Efficiency and Conservation Authority
FTR	Financial Transmission Right
GIP	Grid Injection Point
GIT	Grid Investment Test
GRS	Grid Reliability Standards
GPS	Government Policy Statement on Electricity Governance
GUP	Grid Upgrade Plan
GXP	Grid Exit Point
MED	Ministry of Economic Development
MWh	Mega-Watt hour
RCC	Regional Capacity Contract
Rules	Electricity Governance Rules 2003
SOO	Statement of Opportunities
SPD	Scheduling, Pricing and Dispatch model
TA	Transmission Alternative
TAG	Transmission Advisory Group
TPAG	Transmission Pricing Advisory Group
VOLL	Value of Lost Load
WACC	Weighted-Average Cost of Capital

2.5 General Approach and Overview of the Paper

2.5.1 Overview

43. The part F Rules require that the Commission use the GIT to review Transpower's reliability and economic grid upgrade proposals, and decide to approve or reject them. The GIT is a net market benefits test used to evaluate proposals for investments in transmission or alternatives to transmission under a number of market development scenarios
44. If the GIT determines that TAs are preferable to transmission investment, the Commission then faces two key decisions on TAs. First, whether TAs should be enabled, or whether the Commission should rely on investments occurring in response to information made available to the market. Second, if procurement of TAs is required, whether it should be centralised or decentralised.
45. Section 2 of this paper discusses alternative types of TAs, and the regulatory environment.
46. Section 3 provides a high-level problem definition, key design principles and evaluation criteria, and defines the main procurement options.
47. Section 4 explains the economic and regulatory rationale for determining which of the options is most appropriate. It discusses the importance of each of the identified factors, and draws some conclusions.
48. Section 5 evaluates the options against the evaluation criteria, and provides a qualitative assessment of the options against the Commission's principal objective and specific GPS outcomes.
49. Appendices 1 to 4 provide further details relevant to the market response and procurement options. A full list of consultation questions is provided in appendix 5. Appendix 6 describes the Commission's format for submissions.

2.5.2 Links with other work streams

50. Development of a framework for TAs is clearly linked with the application of the GIT, in that the GIT is used to test the net economic benefits of investments in transmission assets and TAs. The GIT will determine whether transmission or TA investment is the most appropriate choice in each location, taking into consideration grid reliability standards (GRS).¹⁵
51. The development of benchmark agreements to cover connection services is another related area, as contracts for TAs should be consistent with transmission contracts, in order to minimise barriers to competition.¹⁶ The same applies to the Commission's proposal to include in the Rules performance measures for interconnection services.
52. There is a strong linkage with the choice of transmission pricing methodology. The policy for pricing of new investments in the core grid is currently under review. If postage stamp pricing is confirmed for new grid investments, then the costs will be shared nationwide, whereas under location-based pricing the costs will be allocated to parties based on their location. The location-based approach provides stronger incentives for TAs in regions that reduce demand for new transmission capacity.
53. The choice of pricing methodology has implications for the choice of TA procurement regime, as some TA procurement regimes appear to be affected

¹⁵ The Commission's approach to trading-off different forms of reliability investment is provided in papers available on the Commission's website at:

<http://www.electricitycommission.govt.nz/opdev/transmis/gridreliability>.

¹⁶ Refer to the Transmission Service Definition Options paper (April 2005), available at: <http://www.electricitycommission.govt.nz/consultation/tsd>.

by postage stamp transmission pricing. Because a decision on the pricing methodology has yet to be made, this paper considers how each of the TA options would work under both pricing regimes.

54. There are also linkages between TA arrangements, the development of financial transmission rights (FTRs) and hedge market reforms. Moreover, the DP options involve demand-side entities in aggregate contracting with all generation capacity, which may carry significant implications for the Commission's work stream on energy hedges.
55. There are also strong linkages with security of supply and electricity efficiency work streams. Electricity efficiency initiatives can be TAs if they are located in transmission-constrained regions. Transmission security problems carry many parallels with the more general security of supply problems, and solving one can assist with solving the other. The Commission believes it is desirable to adopt a consistent approach across the two work streams.
56. Finally, and most importantly, the approach to procuring TAs carries potentially significant long-term implications for the role of the wholesale electricity market. For example, a decision to specify maximum energy offer prices for generator TAs could directly affect the effective functioning of the wholesale market.

2.6 Types of TAs

57. Part A of the Rules defines the term "transmission alternatives" as "alternatives to investment in the grid, including investment in local generation, energy efficiency, demand-side management and distribution network augmentation set out in part F". Further definition, and some examples, of TAs are provided below.

2.6.1 Generator TAs

58. In this paper the term "generator TA" means any generation plant that defers or avoids grid investment. Generator TAs include grid-connected generation, distributed and embedded generation, cogeneration, and distribution company generation. Generators could be generator TAs if located in 'congested' regions (where grid expansion would reduce nodal prices), such that they reduced net demand for transmission capacity.
59. For example, suppose the commercially optimal decision for a generator is to locate a new gas-fired plant in New Plymouth, because forecast nodal price differences (or realisable revenues relating to this) fail to justify placing the plant near Auckland. Under a TA procurement arrangement, the generator may be able to receive some funding assistance if it agrees to instead locate the plant near Auckland as a means to defer grid expansion that would otherwise be required.¹⁷
60. Generator TAs may also include capacity reserve TAs as discussed below.

2.6.2 Load TAs

61. In this paper the term "load TA" means any load source that defers or avoids grid investment. Load TAs include:
 - a. Demand-side management: This includes interruptible load activated with relays, and load switching and ripple control operated by network

¹⁷ Whether any funding assistance is made available, and if so, the quantum of funding, depends on the detailed design of procurement arrangements. However, it is likely that for generators at least, regulated funding would be a small portion of total revenues.

companies. It may also include capacity reserve TAs as discussed below;

- b. Permanent load switching: This is achieved by consumers locating plant in non-congested areas. For example, suppose the commercially optimal decision for a smelter owner is to locate new plant at a major port, such as at Marsden Point in Northland or at Bluff in the South Island. A new investment in an optimally located load could be considered a TA. In this case, the load TA would provide TA services on a permanent basis, and provision of the TA service would not require the plant to operate any differently beyond the change in location. The Commission believes that the use of this type of TA is less likely than the other types; and
- c. Energy efficiency: This is achieved by consumers installing more efficient consumption technology or using alternative fuel sources such as gas water heating, solar water heating, or compact fluorescent lighting. These TAs would reduce load during peak times by reducing load at all times they operate.¹⁸

2.6.3 Network TAs

62. In this paper the term "network TA" means investments in existing networks such as additional reactive support within distribution networks, or investments that reduce distribution losses at peak times, and thus reduce or delay the need for transmission investment.

2.6.4 Capacity Reserve TAs

63. In this paper the term "capacity reserve TA" means blocks of load or generation contracted to adjust automatically after a transmission contingency event to maintain acceptable flows on transmission circuits.¹⁹ Automated activation allows relaxation of security constraints in the scheduling, pricing, and dispatch (SPD) model, which allows the grid to be operated at higher line ratings, and reduces the frequency and duration of grid congestion.
64. As with all TAs, capacity reserve TAs defer the need for grid investment. For example, an inter-trip protection scheme was recently put in place for the Bay of Plenty in response to high prices caused by transmission congestion into the region.²⁰ This demand inter-trip scheme is an agreement to automatically shed load in response to a transmission contingency, and this allows the System Operator to operate the existing lines closer to thermal constraints (rather than being restricted by security considerations), while still achieving the contracted level of security.

2.6.5 Detailed definition of TAs

65. Aside from the above examples, the Commission has not yet prepared a detailed definition of what constitutes a TA, although some high-level requirements of TAs are specified in the GIT. The Commission intends developing a detailed definition of TAs following consultation on this paper. Such a definition may include (but not be limited to) the following components:
 - Reliability (i.e. must be consistent with GRS, as ensured through application of the GIT);

¹⁸ Note that water heating arrangements that are currently under ripple control may not be able to further reduce load at peak times.

¹⁹ Capacity reserves respond automatically to transmission contingencies, in a similar way to how instantaneous reserves respond to generation contingencies.

²⁰ The Bay of Plenty capacity reserve scheme allowed transmission investment in the Bay of Plenty to be delayed by approximately 18 months.

- Size (in terms of how much grid deferral a TA must provide)²¹; and
 - Operational constraints / certainty.
66. A recent report²² prepared by NZIER and Stratagen argues that TAs must deliver capacity benefits similar to transmission services. It also argues that TAs must provide the same level of availability, reliability and permanence as specified in the GRS,²³ the same quality of power as that available through transmission, be reasonably certain of proceeding, and take account of competition effects. The report identifies increased reticulation of alternative fuels and installation of significant quantities of distributed generation as TAs worthy of further consideration.
67. The Commission notes that the report provides a useful starting point with regard to developing a detailed definition of TAs. The Commission notes that defining the factors identified by the study will be considered as part of the GIT and that, as noted in clause 19 of the GIT, TAs need not provide equivalent capacity or reliability as transmission investment. The high-level analysis of options in the study appears to suggest that options that are not equivalent to transmission investment should not be considered, but the Commission considers that this conclusion does not take account of the ability of TAs to meet the GRS and GIT criteria.

2.7 Regulatory Environment

2.7.1 Rule requirements on the Commission

68. A key change in introducing the Rules was the move to a regulated decision making process for transmission investments. Rule 2.2 of section III of part F states that a purpose of section III is to assist participants to identify and evaluate investments in TAs. The Commission notes that the Rules do not provide sufficient direction on the processes that should be followed to procure TAs (if this approach is decided upon), and there is no explicit provision in the Rules for the TAs to be procured or funded.
69. Rules 9.1.2 and 11.2 of section III of part F require the Commission to consider TAs in preparing SOOs and the CDS, and rule 6.2 requires the Commission to use the GIT to review TAs.
70. Rule 13.3.3.4 of section III of part F empowers the Commission to ask Transpower, where Transpower possesses the relevant expertise, to evaluate TAs, and rule 14.3.2.2 empowers the Commission to direct Transpower to investigate and apply the GIT to TAs.

2.7.2 GPS requirements and legislative requirements

71. Although there is no mention in part F of the Rules of procuring TAs, it has been clear for some time that the Government has contemplated such measures. For example, the Ministry of Economic Development's (MED) explanation of the final part F Rules indicated the Government was considering removal of any potential legislative barriers to Transpower contracting with generators to provide transmission alternatives.²⁴

²¹ Note that the GIT specifies (clause 19) that transmission alternatives must provide similar benefits in type but not necessarily in magnitude, as the proposed (transmission) investment.

²² *Transmission Alternatives: Criteria for their identification*, Report to Meridian Energy (May 2005).

²³ Note however that the GRS does not specify required availability, reliability or permanence.

²⁴ "Explanation of decisions and response to submissions", MED, 18 March 2004, page 22.

72. In addition the Electricity Industry Reform Act 1998 makes provision for Transpower to contract with electricity supply businesses (generation) for the purposes of delaying transmission investment.²⁵
73. Paragraph 90 of the GPS requires the Commission to “consider whether there would be net benefits in providing for a mechanism whereby investments in transmission alternatives receive payments reflecting some or all of the value of avoided transmission investment”. This paper specifically advances this policy requirement.

2.7.3 The Minister’s letter

74. In addition, on 13 April 2005, the Minister of Energy wrote to the Commission setting out the Government’s expectations regarding the process it will undertake for approving the first GUP. The Minister requested the Commission, when considering Transpower’s proposed Auckland grid upgrade, to undertake a thorough investigation of alternatives to the proposal, including alternative generation and demand-side options and alternative transmission options.

2.8 Existing TAs

75. A number of TA investments have occurred in New Zealand without the existence of procurement arrangements in the Rules. These include:
- a. Network alternatives, such as the investment in reactive support in the upper North Island in 1999/2000;²⁶
 - b. Generator inter-trips and runback schemes, such as those installed at Cobb (2000), Maraetai (2003), Te Awamutu (2000), Coleridge (2000), Manapouri (2003) and Te Apiti (2004);
 - c. Demand inter-trips, such as those installed at Blenheim²⁷ (2004), Kawerau²⁸ (2002), Nelson/Marlborough²⁹ (2004) and Christchurch³⁰ (2004);
 - d. Bus-splitting schemes that improve flow through the system by reducing local security, such as in Hawera (2003), Mangamaire (2001) and Tokaanu (2000);
 - e. Areas where local generation is contracted to provide N-1 security, such as in Southland, North of the Waitaki Valley, South Island West Coast, Nelson/Marlborough, Gisborne and Tauranga;
 - f. Ripple control systems that are used to manage domestic hot water and space heating loads at times of peak load;³¹ and
 - g. Market investment in generation, for instance security limits have been (or will be in future) substantially increased into the upper North Island as a result of the Otahuhu B, Southdown, Genesis p40, and (proposed) Genesis e3p power stations.

²⁵ Section 5(3)(a).

²⁶ An industry process to manage expected security of supply issues resulted in the installation of 360 MVar of reactive support, 260 MVar of which was provided by distribution network companies as a lower cost alternative to Transpower’s grid solutions.

²⁷ A temporary scheme until the 3rd circuit between Islington and Kikiwa is constructed.

²⁸ A temporary scheme until the thermal upgrade was completed.

²⁹ A temporary scheme until the 3rd circuit between Islington and Kikiwa is constructed.

³⁰ A temporary scheme until capacitors are installed.

³¹ Note that many of the ripple control schemes in place today were initiated during a time when bulk supply tariffs (which priced both electricity and transmission on a peak basis) provided very strong incentives for peak load control.

76. In the majority, if not all, of these cases, the cost allocation mechanism for transmission investment (Transpower contracting with users) provided the right incentives for provision of TAs, i.e. it allowed TA providers to avoid the transmission investment costs. The System Operator is continuing to procure voltage support TAs and recovering these costs on a regional user pays basis.
77. Similarly these TA investments mostly occurred in situations where the provider was able to capture sufficient benefits of the investment to enable them to proceed. Thus the free rider issues identified in section 4 did not apply to these investments.
78. The Commission considers it likely that market-driven TA investment is unlikely to occur in place of investment in the interconnected network in the future for the reasons outlined in sections 4 and 5 of this paper.

3. Options for Transmission Alternatives

79. This section summarises the policy rationale for procuring TAs, lists the design principles and evaluation criteria for developing and assessing the options for procuring TAs, and provides a detailed description of the main options.
80. The paper considers and evaluates the following options:
- Option 1: market response;
 - Option 2: universal central procurement (universal CP);
 - Option 3: minimal central procurement (minimal CP);
 - Option 4: limited decentralised procurement (limited DP); and
 - Option 5: full decentralised procurement (full DP) or regional capacity contracts (RCC).
81. There are a number of possible variants of these options, which are discussed in section 3.9.

3.1 Problem Definition

82. The Commission uses the GIT to determine whether GUPs should be approved or rejected. This requires consideration of whether TAs are more efficient than grid investment.
83. As TA investments may be used to substitute for grid investments, the Commission needs reasonable confidence they will occur within timeframes needed to achieve reliability requirements.
84. Identifying efficient TAs will not be sufficient for the Commission to reject a proposed grid upgrade. It will also need reasonable certainty that TAs will materialise within required timeframes if a grid reliability investment is to be rejected.
85. Historically, TAs have emerged in a number of locations based on local requirements. However, the Commission believes it is possible that some TAs may not have emerged because of:
- a. *Free rider problems*: all consumers in a region benefit from the actions of other consumers or local generators who reduce demand for transmission, and thereby reduce nodal prices and transmission charges for all consumers.

Unlike consumers, most generators should be able to avoid free rider problems with nodal pricing because they can adopt offer strategies to avoid nodal prices collapsing after having made their investments. Nevertheless generators may still suffer free rider problems in regard to transmission charges, because their ability to capture avoided transmission costs depends on their ability to contract with (often multiple) parties paying transmission charges.

This problem does not exist to the same degree with investments in connection and spur assets because deep connection charges are more strongly targeted to beneficiaries of the investment; and
 - b. *Commitment problems*: TA providers, particularly generators, are less likely to commit to large sunk investments if Transpower can strand their investment by subsequently undertaking its own investments and recovering costs through regulated means.

86. The free rider problem also used to exist for investment in transmission assets. However, part F of the Rules now gives Transpower the regulated right to collect revenue related to those approved asset investments. Similar arrangements do not exist for TAs, which tilts the 'playing field' in favour of grid investment, resulting in potentially uneconomic grid investment.
87. In light of the part F arrangements, the Commission considers that TAs are even less likely to occur in the future without credible and robust arrangements for TAs to defer grid expansion. This is particularly likely to be the case on the core grid, though less likely in radial sections of the grid.
88. The Commission, therefore, is considering TA arrangements for inclusion in part F of the Rules that:
- a. Achieve a lower total cost of delivered electricity by ensuring TAs are implemented when they are cheaper than grid reliability investments;
 - b. Achieve reasonable certainty for the Commission that, if it rejects a grid upgrade proposal on the grounds that TAs are more efficient, TAs of appropriate reliability³² will eventuate within required timeframes; and
 - c. Minimise risks to the market environment, in terms of the potential for the regime to lead to increasing central planning of the generation sector ('the slippery slope').
89. Note the Commission is only considering TA arrangements needed to achieve reliability of supply ("reliability TAs"). Although TAs substituting for grid economic investments may suffer from the 'free rider' problems discussed above, the Commission does not require the same degree of certainty about them as it does for reliability TAs.

Q2: Do submitters agree with the problem definition outlined above? Why or why not? Do submitters consider the optimal amount of transmission investment and TA investment has emerged in the past? Why or why not?

3.2 Design Principles for TA Procurement

90. The Rules provide the Commission with specific principles for the consideration of Transpower's transmission pricing methodology and objectives for the development of the GIT.³³ Similar design objectives or principles have not been specified for developing policies and procedures for procuring TAs, as analysis regarding procurement of TAs had not been undertaken at the time part F of the Rules was finalised.
91. The Commission's principal objectives and the specific outcomes required of it are well known, and are provided in Table 7 in section 5.4 of this paper. Reviewing them suggests that TA procurement policies and procedures should, as far as practicable:
- a. Promote a level playing field between grid investments and TAs, and between alternative types of TAs, so that the lowest cost options are procured consistent with grid reliability standards;
 - b. Maximise opportunities for innovation in the provision of TAs to reduce the costs of electricity over the long run;
 - c. Provide reasonable certainty that TA investments will occur within required timeframes (and will operate when required);

³² The term "appropriate reliability" is intended to indicate consistency with the GRS, and reliability/cost trade-offs made through the GIT.

³³ Design objectives for the GIT are specified in rule 6.3 of section III of part F of the Rules. The principles for the pricing methodology are specified in rule 2 of section IV of part F.

- d. Promote certainty for investment in the grid and investment by grid users;
 - e. Minimise adverse effects on the competitive sectors of the market (i.e. minimise 'slippery slope' risks);
 - f. Be consistent with the GIT and other transmission and security of supply work streams; and
 - g. Minimise administration and compliance costs.
92. Section 5 evaluates the main options against the above objectives and design principles. Note that question 1 in the executive summary asks for submitters' views on whether the above design principles are appropriate.

3.3 Central Procurement Agency

93. One important consideration for operation of a procurement regime is determining which party should fulfil the role of central procurement agency (should one be required).
94. The Commission does not intend to take on the role of central procurement agency. Rather, it believes that this is a service provider role, and believes that it could be carried out by the System Operator, for the following reasons:
- It is an existing service provider, and already undertakes a procurement role, being procurement of ancillary services.³⁴ Including TA procurement in its scope aligns with current System Operator processes, and would therefore enable scale economies in its activities to be exploited;
 - It has the administration, planning and operating competencies likely to be required for such a role; and
 - It is not conflicted in carrying out the role.
95. In addition to procurement, the central procurement agency role will include a number of other tasks, as alluded to throughout this paper. For example, the allocation of transmission capacity and forecasting of requirements may be carried out under this role, following development of guidelines. However, other tasks that have also been ascribed to the central agency in this paper are likely to fall outside the central procurement agency role, for example, verification, compliance, and enforcement functions may be better carried out by another party.³⁵
96. The Electricity Industry Reform Act 1998 allows Transpower to contract with electricity supply businesses for electricity generation, for the purpose of deferring the need for new investment by Transpower in the national grid. As the System Operator is not a separate legal entity from Transpower, this provides the legal basis for the System Operator to carry out the central procurement task.

Q3: Do submitters agree with the Commission's view that the System Operator could undertake the service provider role of central procurement agent? Why or why not? Do you see any problems with such an approach?

³⁴ Note that cost allocation for TA costs would be separate from ancillary service cost allocation. The former would occur under part F, and the latter under part C.

³⁵ The roles of the Commission, the System Operator, and other parties will be developed in detail following selection of a preferred option (unless the status quo is selected as the preferred option). This paper assumes that the System Operator could take on the actual procurement role.

3.4 Option 1: Market Response Investment in TAs

3.3.1 Introduction

97. The market response option would involve increasing information (through the GIT and other processes) to market participants regarding opportunities for TAs. While a TA may emerge from the GIT as the preferred option, whether or not it eventuated would be left to the market to determine.
98. This option, which is the counterfactual for the evaluation, does little to address perceived barriers to development of TAs. The market response option is essentially a “do nothing” option, although relative to the situation prior to the commencement of part F of the Rules, it includes increased information provision, and may also include the effect of electricity efficiency benefits delivered through other policy mechanisms currently being developed by the Commission and the Energy Efficiency and Conservation Authority (EECA).
99. The market response option would be appropriate if transmission pricing, nodal pricing, and the GIT provide adequate investment incentives for TAs, and if nodal pricing deficiencies are not serious enough to justify offsetting the dynamic efficiency losses arising from regulatory intervention in market investment decision processes.
100. A key risk of the market response option is that the Commission may reject Transpower’s GUP on the presumption the market will provide appropriate generation and demand responses, only to find insufficient market response occurs within required timeframes. Alternatively, the Commission may *not* reject a grid upgrade proposal, even if the GIT shows that it provides lower net benefits than TAs, because of the lack of certainty.
101. Some specifications for the market response option already exist in the part F requirements. These are discussed below.

3.3.2 Part F requirements

102. Part F of the Rules requires the Commission to assist participants to identify and evaluate investments in TAs.³⁶ In particular, the Commission is required to publish a SOO that identifies potential opportunities for TAs.³⁷ In preparing the SOO, the Commission is required to formulate grid planning assumptions regarding:
 - a. Committed projects for generation and demand-side management;
 - b. A range of credible future, high-level generation scenarios; and
 - c. A range of demand forecasts.³⁸
103. The Rules also require the Commission to use the GIT to review TAs.³⁹ The process underlying these requirements is shown in appendix 1.

Identifying TAs

104. The Rules require the Commission to assist participants to identify TAs. The Commission believes this requirement would be best met by publishing the SOO and identifying generic opportunities for TAs.

³⁶ Rule 2.2 of section III of part F.

³⁷ Rule 9.1 of section III of part F.

³⁸ Rule 10.3.1 of section III of part F.

³⁹ Rule 6.2.4 of section III of part F.

Evaluating TAs

105. Although the Rules require the Commission to assist participants to evaluate TAs, the extent to which specific TAs must be assessed under the GIT is not clear. The Commission expects that conducting the GIT based on generic TA models (based on SOO scenarios) will be sufficient in most cases. A more thorough investigation of TAs will be undertaken when this is necessary to determine the outcome of the GIT.

Contractual requirements

106. Under the market response option the Commission is not directly approving or rejecting alternatives to transmission. However, its approval (or otherwise) of Transpower's grid upgrade proposals has a similar effect. In a nodal pricing environment with large economies of scale, approving a grid investment removes commercial drivers for TAs, and rejecting or deferring a grid investment preserves commercial opportunities for TAs.
107. If the Commission determines that TAs are preferable to grid investment under the market response option, it then relies on proponents of TAs to finance and install them. TA providers have no contractual obligation to the Commission to proceed with their proposal, or to offer all or part of their facility to the market when net demand in a region exceeds transmission capacity to that region. In practice, under this option, TAs are not likely to provide a practical alternative to grid investment.

Regulatory oversight

108. Although TA providers would have no contractual obligations, the Commission will still wish to monitor progress with the installation of TAs as part of its ongoing 'needs analysis' for grid investment. The Commission could then look at mechanisms to delay or postpone earlier approved transmission investments if this was economically rational.⁴⁰

3.3.3 Market response proposal

109. In the event the market response option is selected, the following process would be followed:
- a. The Commission publishes the SOO, identifying generic opportunities for TAs;
 - b. Transpower proposes a GUP;
 - c. The Commission applies the GIT to the GUP, including TAs investigated by Transpower and any other alternatives that have been proposed;
 - d. The Commission approves or rejects Transpower's GUP;
 - e. Parties respond to the approved and rejected transmission upgrades, and decide whether to invest in TAs; and
 - f. The Commission monitors investment progress with TAs, and if necessary, reconsiders grid investment proposals.

⁴⁰ In order to manage project risks, most major capital projects have mechanisms available to delay final commitment while still meeting timeline commitments. However, after a critical point, no benefit can be obtained from deferral or abandonment due to necessary commitments to construction contractors. This critical point may, however, still be before proponents of TAs need to commit to meet the same grid reliability requirements.

3.5 Option 2: Universal Central Procurement (universal CP)

110. Under the universal CP approach, all TA proposals relevant to deferring a proposed grid reliability investment would be eligible for regulated procurement, provided they satisfy the GIT. The System Operator (as central agent) would determine the total quantity of TAs that should be procured in each region to meet reliability requirements, using the GIT and generic TA models as described for the market response option. The System Operator would also conduct tenders to procure TAs.
111. The procurement contracts under this option specify maximum prices at which generator TAs are allowed to offer energy into the market when operating as a TA, which will most likely be based on the short-run marginal costs (SRMC) offered in their TA tender proposals. The procurement contracts will also place other operational constraints on generator TAs, and in particular will require them to offer energy to the market during times when the System Operator declares a regional capacity shortfall.

3.5.1 Tenders

112. Full details of the design of the tender process have yet to be developed. A contestable process between competing demand-side and supply-side options would be established, with the criterion for selection being maximising net economic benefit under the GIT, not the amount of fee offered in the tender. For proposals providing equal net benefits under the GIT, the Commission will prefer lower priced tender offers.
113. To the extent that the tender process is successful in eliciting a range of competitive bids, then selection will reflect both the cost and the net economic benefit of the TA. If the tender process is not sufficiently competitive, then TA providers will receive a price greater than cost.⁴¹ In this manner, demand-side proposals could attract substantial funding, up to the opportunity cost of supply-side options. Measurement and confirmation of performance and compliance would be a key issue for demand-side options.

3.5.2 Maximum energy price offers

114. Relying on generation TAs to defer or avoid grid reliability investment without limiting their offer prices may allow generation TAs to exercise market power that would not have been possible if the grid investment had occurred. In this situation the Commission could be perceived as deliberately creating a situation in which a generation TA could exercise market power, or perhaps continue to exercise existing market power.
115. Under the universal CP option generation TAs would be required to offer energy to the market at their marginal cost of supply during periods when they are instructed to offer energy to the market. In real terms, this mimics the zero-price offers made by grid owners, as generation TAs receive revenue to cover their energy costs, and are in effect receiving a zero price for their provision of TA services.
116. Since generators receive whatever spot price prevails at their injection nodes, generation TAs would receive revenue reflective of nodal prices for provision of TA services. Generation TAs would be free to choose any offer price during other trading periods.
117. The rationale for constraining offer prices to marginal cost is that it protects TAs from receiving market prices below their marginal cost of supply during periods when they are instructed to offer energy to the market. Without this

⁴¹This is a wealth transfer to the providers of TAs, and will not affect grid investment decisions under the GIT.

protection TA providers may become unwilling to supply TA services upon demand.

118. Appendix 2 discusses in more detail the options for constraining offer prices, and recommends that no price constraints be adopted. This is the proposed approach under the minimal CP option discussed in section 3.5.

3.5.3 Other constraints

119. Other constraints would also be imposed under the universal CP option, such as:
- a. Availability (affected by unplanned outages) would be managed through the use of financial incentives for over-performance and penalties for under-performance;
 - b. TAs would be required to provide service upon the demand of the System Operator (providing certainty of availability);
 - c. TAs would be required to obtain approval for planned outages from their contract counter party, to ensure planned outages do not occur during likely system peaks; and
 - d. No restrictions would be put on a TA's ability to provide reserve energy or instantaneous reserves, while also being a TA.
120. Threshold criteria may be required for the universal CP approach, to enable the System Operator to avoid dealing with proposals for which the benefits are likely to be outweighed by transaction costs.
121. Appendix 2 discusses in more detail the rationale for the above operating restrictions.

3.6 Option 3: Minimal Central Procurement (minimal CP)

122. Under the universal CP approach all TAs are eligible to participate in tenders regardless of whether they would have occurred anyway without regulated revenue. In contrast, the minimal CP option targets assistance to TAs that are not likely to occur without regulated funding, and as a result, less prescriptive arrangements are adopted regarding price offers and operational restrictions.
123. Eligibility for regulated funding would be determined by subjecting TA proposals to several tests (described below) before allowing them to participate in tenders. TAs that are ineligible for regulated procurement will be expected to occur through market-based investment decisions (because there is no market inefficiency for those TAs).

3.6.1 Eligibility for procurement

124. Appendix 3 provides a detailed description of the rationale underlying the eligibility tests. The Commission is proposing to use three tests to avoid funding TAs that would occur anyway:
- a. The free rider test;
 - b. The commercial test, which involves the Commission assessing the commercial returns to TA proposals to determine whether they would occur anyway even with free rider problems; and
 - c. The price cap test, which involves assessing whether implicit or explicit price caps undermine the commercial viability of peaking plant.

3.6.2 Energy price offers

125. The Commission believes constraining the offer prices of generator TAs would greatly increase regulatory intrusion in the wholesale market, and would

greatly exacerbate 'slippery slope' risks. The minimal CP option reduces these problems by not constraining offer prices.

126. This approach is also justified on the grounds that other parties would have incentives to enter the market to restore competitive price levels if generator TAs set their offer prices consistently too high. It is also justified on the basis that constraining offer prices for specific generation plants is likely to prove ineffective in practice.
127. For example, a generator owning TA and ordinary generation plants could exercise market power by offering its ordinary plant to the market at very high prices. It does not matter which plant they use to exercise market power since all dispatched energy is paid essentially the same price.⁴²

3.6.3 Other operational constraints

128. The minimal CP option requires only a commitment from TA providers to build and operate their plant, and to co-ordinate planned outages with the System Operator.⁴³ In contrast to the universal CP option, the minimal CP option relies on the commercial incentives on TA parties to increase local energy or reduce local demand as nodal prices rise. This is in fact what happens now, and will achieve certainty regarding the availability of generation capacity.
129. The benefit the generator receives from TA contracts under the minimal CP option is increased certainty the Commission will not change its mind on grid investment decisions and leave it with a stranded investment. The benefit the Commission receives is increased certainty the TA provider will proceed with its proposal.

3.6.4 The procurement process

130. The following process would be adopted under the minimal CP option:
 - a. Following determination of a TA requirement in the GIT, the Commission approves appropriate grid upgrades, and the System Operator solicits TAs through a formal request for proposal (RFP) and tender processes;
 - b. Eligibility tests are applied to proposals to assess whether TAs being considered would fail to emerge in the absence of procurement, due to free rider problems;⁴⁴
 - c. Cost-benefit analyses of eligible proposals are conducted (by region), based on net market benefits;
 - d. The System Operator procures qualifying TAs at rates based on competitive tender bids;
 - e. Other parties can undertake market response investments in TAs, taking into account approved grid investments and procured TAs; and
 - f. Costs for procured TAs are recovered through a specified cost allocation. For example, this could be based on the transmission pricing methodology.

⁴² Prices will not be equal due to losses. Also, note that the presence of the generation TA means that grid constraints do not bind, and so all dispatched energy, not just energy dispatched in the region, receive essentially the same price. The paper sometimes uses "constrained regions" in quote marks to denote regions where peak demand exceeds transmission capacity.

⁴³ Financial penalties would be levied for any non-performance on these commitments.

⁴⁴ This assessment would use tests such as those discussed in Appendix 3.

3.7 Option 4: Limited Decentralised Procurement (limited DP)

131. The limited DP approach is similar to the minimal CP approach except that procurement is carried out by DSEs rather than by the System Operator. There are no price constraints and no operational restrictions proposed under the limited DP option.
132. The System Operator determines the total quantity of TAs to be procured in each region to meet reliability of supply requirements, and assigns capacity obligations to DSEs to procure TAs, based on their share of regional peak demand. Under this option, DSEs' compliance with their capacity obligations is monitored, and the System Operator verifies that TAs meet reliability requirements. Financial penalties are imposed on DSEs for not meeting their obligations.

3.7.1 The procurement process

133. The limited DP process would involve the following steps:
- The GRS, SOO, and GIT are used to determine the requirements for transmission and TA investments. Approved transmission investments are progressed, and any new transmission capacity, together with existing transmission capacity into a region, is allocated to DSEs on a regional basis;⁴⁵
 - Capacity requirements for each DSE in each region are determined. This is likely to require DSEs to forecast regional peak demands, based on guidelines, and submit them to the System Operator, which then uses these forecasts to determine the capacity requirements for each DSE. It may include a margin or multiplier to deal with a TA failure to operate;⁴⁶
 - DSEs procure TAs to meet their capacity requirements less their allocation of transmission capacity into the region;⁴⁷
 - In the event that a DSE fails to procure sufficient TAs, or procures a TA that fails to operate, it faces a financial penalty; and
 - The penalty regime is set so as to deal with any transmission pricing free rider issues.

3.7.2 Interaction with transmission pricing

134. A general issue for any DP option is consistency with the pricing methodology for new grid investments. The Commission has not yet determined whether to adopt postage stamp or locational pricing.
135. Under a postage stamp approach with DP, parties would face the full costs of TA investment but less than the full cost of grid investment. In comparison, under locational based pricing for new grid investments, parties would face the full cost of either TAs or transmission, so they face incentives to support the most economic outcome, whether it is transmission or TAs.

Equity complications

136. If disparate pricing (cost allocation) methodologies are adopted for TA and grid investments (i.e. postage stamp pricing for transmission, but more localised

⁴⁵ As for the RCC option (see section 3.8), this requires definition of regions, and determination of an allocation methodology.

⁴⁶ This is a proposed means to avoid the need for a penalty regime, as it is envisaged that this would be relatively onerous to design and operate.

⁴⁷ Required TA specifications may be determined centrally or by the individual DSE.

pricing for TAs) then GIT decisions would carry significant wealth transfer or equity implications, rendering them far more controversial than necessary.

137. Over time this disparity could lead the Commission into considering equity and fairness issues when making GIT decisions, rather than just net economic benefits as the GIT is currently specified. The Commission considers this direction would ultimately undermine the basis for making transparent, robust, and credible decisions on grid upgrade proposals.
138. The DP options are consistent with location-based grid charges because the allocation of capacity obligations will be regional (i.e. location-based). The case for adopting a DP approach relies significantly on adopting location-based transmission pricing levied at long-run marginal cost (LRMC) rates, whereas the CP options can be implemented under postage stamp transmission pricing.

Penalty issues

139. All DP options assign responsibility for procuring TAs to DSEs, and rely on financial penalties to enforce DSE compliance. Under postage stamp transmission pricing, DSEs know that they face the full costs of procuring TAs but only a fraction of the costs of grid investment. This provides them with incentives to purchase less than the mandated amount of TAs, or at least to lobby for grid investment rather than TA investment.
140. These incentives can be addressed via a penalty regime for non-procurement. However, to be efficient, such a penalty regime would need to reflect the cost difference between the transmission charges paid by that party and the true cost of grid investment. The penalty under this regime would be very large, as it needs to be the present value of these cost differences.

3.7.3 Further work is required on the limited DP option

141. The limited DP option has been developed late in the process of preparing this paper, and although it has received considerably less development time than the CP options, some comfort can be taken from the fact that it draws heavily from the minimal CP and RCC options.⁴⁸
142. At this stage the Commission believes fundamental issues will need to be addressed with the way in which capacity obligations for each region are determined. In particular, the Commission is concerned that the DP options are likely to involve similar computation complications as would occur with introducing location-based transmission charges. There are also significant issues to address regarding the basis for allocating capacity obligations among DSEs, and the basis for monitoring and verifying the level and reliability of TA capacity.
143. The Commission believes these issues need to be considered further, and would particularly welcome comments from interested parties on these points.

3.8 Option 5: Regional Capacity Contracts (RCC)

144. Early in 2005, Contact Energy proposed a decentralised procurement arrangement, called regional capacity contracts (RCC).⁴⁹ This approach was proposed to provoke discussion on alternatives to central procurement, and if implemented, would reduce or negate the need for central procurement of TAs. The proposal is still under development.

⁴⁸ See sections 3.6 and 3.8.

⁴⁹ Details on the proposal are available on Contact Energy's website at: <http://www.mycontact.co.nz/view?page=/forinvestment/publications/governmentsubmissions>.

145. The RCC proposal is a transmission-focussed and regionalised variant on "Installed Capacity" (ICAP) requirements as implemented in various United States jurisdictions.⁵⁰ Under ICAP, load-serving entities within each region are required to self-supply or contract for installed generation capacity or demand response capacity, based on a forecast peak demand and each load-serving entity's share of that peak. If its actual peak demand exceeds its allocated quantity the load-serving entity is charged a penalty related to the cost of providing new generation services.
146. The RCC proposal applies the ICAP concept to regional generation and transmission capacity. As for the limited DP option, the RCC proposal places the responsibility for procuring capacity on DSEs rather than on the System Operator. The required capacity takes into consideration existing transmission capacity and the contribution of each DSE to forecast peak load.⁵¹ The RCC proposal suggests that DSEs should also determine their own capacity requirements, but be held accountable with financial penalties.⁵²
147. The RCC approach will allow existing local generation to be used to meet capacity contract arrangements. It could be argued that the RCC approach will result in windfall gains for such investment, but note that if these investments were made under the previous arrangements for transmission investment (where transmission investment was less likely), it could be argued that a RCC approach avoids stranded investment.
148. Secondary trading would enable DSEs to buy or sell RCCs to match their forecast requirements as these change closer to real time.
149. A verification and penalty regime is included in the proposal, as this would be necessary to address the situation where a DSEs actual contribution to the regional peak demand exceeded its RCCs. The penalty would be significant (related to the value of lost load, or VOLL) so that it would ensure that DSEs had adequate incentives to truthfully and realistically forecast their peak requirement, and therefore contract for sufficient TAs.
150. The proposed regime would operate on an annual basis, and DSEs would be required to obtain RCCs 18 months ahead of time to meet the relevant regional peaks. Note that DSEs may be either retailers or line companies (and may also include large directly connected consumers).
151. A review of the RCC proposal is provided in appendix 4.

3.8.1 Specification of the RCC proposal

152. The RCC option would involve the following steps:
 - a. The GIT determines the requirements for transmission and TA investments. Any new transmission capacity, together with existing transmission capacity into a region, is allocated to DSEs on a regional basis.⁵³

⁵⁰ It is also a feature of the Federal Energy Regulatory Commission's (FERC's) next version of Standard Market Design, Order 2000.

⁵¹ Existing transmission capacity is allocated to each DSE based on historical contribution to the regional peak demand. DSEs forecast (18 months ahead of real time) their future contribution to future regional peaks, and then must contract for sufficient TAs to ensure that their forecast peak load can be met by a combination of allocated transmission capacity and TAs. RCCs are held by the DSE for each qualifying generation TA. Demand-side TAs are recognised indirectly by reducing the DSEs requirements for RCCs.

⁵² Note that this is a significant difference from the limited DP option, under which quantity requirements are determined and allocated centrally.

⁵³ Note that this requires definition of regions, and determination of an allocation methodology.

- b. DSEs forecast their own capacity requirements for each region based on set guidelines, and submit these to the System Operator;
 - c. DSEs procure RCCs to meet their capacity requirements less their allocation of transmission capacity into the region;
 - d. In the event that a DSE fails to procure sufficient RCCs to meet its forecasts, it faces financial penalties. This provides the DSE with incentives to accurately forecast peak load, and gives the Commission confidence that planned TAs will emerge; and
 - e. In the event that a DSE procures an RCC that fails to operate, the System Operator identifies this and penalties are applied. This provides DSEs with incentives to ensure their contract capacity is likely to operate when called upon to do so, and is intended to give the Commission confidence that the planned TAs will operate when required.
153. It is important to note that under both the RCC proposal (above) and the generic decentralised option (below), the policy framework is still provided by the regulator, and intervention is relatively significant.

3.8.2 Transmission pricing issues

154. The equity and penalty issues discussed above for the limited DP option apply equally to the RCC option.

3.9 Other Options

3.9.1 Variants to the CP options

155. There are a number of variants to the above options. For example, the universal CP option could be made less universal by introducing the tests proposed for the minimal CP option, or it could be made less intrusive by removing the price setting requirements.
156. Similarly, the minimal CP option could be made more minimal by ruling out *generation* (and possibly also demand-side) TAs as candidates for central procurement. No payments would be provided to generators under this option on the basis that in large part they do not suffer free rider problems in regard to nodal pricing, and removing them from the procurement process would go a long way to reducing 'slippery slope' risks.⁵⁴
157. Under this approach – which could be called the “commitment variant of the minimal CP option” – the Commission calls for TAs to contractually commit to build and operate their plant within required timeframes, and approves Transpower’s grid upgrade plans if commitments are insufficient to delay grid investment.
158. Although the commitment approach has some attractions to the Commission, there are several issues to resolve about the statutory ability of the Commission to implement it.

3.9.2 Hybrid options

159. The Commission is also open to the possibility of adopting a hybrid approach, where the minimal CP option and the limited DP option are implemented in

⁵⁴ Depending on the issue to be addressed with demand-side TAs, they may or may not receive funding under such an option. It should also be noted that, though demand-side TAs may receive payments under this variant, work to date suggests that the extent to which demand-side options will be able to defer or replace transmission investment will be considerably less than supply-side options.

parallel. This could involve the System Operator conducting tenders, and then setting capacity obligations on DSEs to meet remaining requirements. The residual nature of the capacity obligations would tend to focus DSEs on small capacity TAs, such as from load and network options, distributed generation, and generation peaking plant.

160. Alternatively, if a DP regime is considered to be the best approach, one of the CP options could be used initially to provide the Commission with sufficient comfort to defer transmission investment if that was the outcome of the GIT. By the time a second round of TA procurement became necessary the Commission could have examined the effectiveness of the DP regime and elected to scale back or eliminate the CP option if the DP regime was judged to be successful.
161. Although the Commission has not developed or evaluated these other options, it is interested in hearing submitters' views on them and other options they believe warrant further consideration.

- | |
|---|
| <p><i>Q4: Do submitters agree that DP options are inconsistent with postage stamp pricing for new grid investments? If not, please explain.</i></p> <p><i>Q5: Do submitters believe any of the "other options" in section 3.9 should be developed further? Are there other options not covered in this paper that should be considered?</i></p> <p><i>Q6: In the event that a DP regime is selected for further development, should DSEs be retailers or distribution companies? Explain your response.</i></p> |
|---|

4. Economic and Regulatory Arguments

4.1 Introduction

162. This section considers the policy rationale for and against procurement of TAs, covering the following issues:
- a. Investment certainty and commitment;
 - b. Free rider issues in regard to transmission charges;
 - c. Free rider issues in regard to nodal prices;
 - d. Other deficiencies with nodal pricing; and
 - e. 'Slippery slope' risks.
163. Whether TA procurement is preferable to the market response option depends on how significant the problems in (a) to (d) are believed to be, and whether any of the alternative options can address those problems effectively without seriously impacting on market arrangements for the competitive sectors of the electricity industry.
164. Section 5 of the paper draws on these factors to evaluate each of the options.

4.2 Investment Certainty and Commitment

4.2.1 Arguments for procurement

165. Investment certainty arguments for procurement are based on the premise that it may be difficult for the Commission to justify a decision to defer reliability investment proposals from Transpower *on the prospect* that TAs will eventuate within timeframes required to avoid supply shortages. Procuring TAs would provide greater certainty that TAs will eventuate within required timeframes, making it easier for the Commission to defer grid reliability investments if other options produce larger net economic benefits for New Zealand.
166. TAs can also provide a safety margin to address uncertainty about future demand growth, and provide the Commission with options to deal with unanticipated delays in expanding grid capacity.
167. Furthermore, TAs assist with the current environment of heightened uncertainty regarding fuel supplies and the location of new generation. Unlike grid expansion, which involves very large one-off sunk investments, TAs are generally smaller-scale capacity expansions. Procuring them keeps grid expansion options open until fuel and generation uncertainties have been mitigated or resolved.

4.2.2 Counter arguments

Long lead times with the pre-build phase

168. Long lead times involved with the pre-build phase of grid investment mitigate the investment certainty arguments to some extent.
169. For example, the Commission could approve Transpower's proposed expenditure to acquire consents and easements, and to prepare designs for grid expansion, then make final decisions on the full project at a later date, contingent on the progress TA investors make with their projects and the latest

forecast costs of the transmission project.⁵⁵ TA investors would then have time to develop and install projects. It is, however, instructive to note that such an approach still requires commitment from TA investors prior to the point at which grid reliability investment is required.

Repeated game

170. Opponents of procurement argue the Commission will be required to make grid investment decisions on a regular basis, and the repeated nature of the decision will reduce the commitment problem over time, as the Commission and its stakeholders become familiar with the 'checks and balances' built into the decision-making process.
171. In addition, the repeated nature of the decision process may allow the procurement agency to limit the timeframe and scale of any procurement contracts – that is, TA contracts only need to be enough to delay the grid investment decision until the next round.

4.2.3 Conclusion

172. The Commission believes the investment certainty argument for procurement of TAs has some merit, provided dynamic efficiency losses from procurement are less than the cost savings from substituting TA investment for grid reliability investment.

Q7: Do submitters agree with the assessment of the investment certainty and regulatory commitment issues? Why or why not?

4.3 Free Riding on Transmission Charges⁵⁶

173. TA investment signals derive from both nodal prices and transmission charges, and free riding can occur in regard to both types of pricing signal. This section discusses transmission charges, while section 4.4 covers free riding on nodal prices.
174. Policy decisions have yet to be made by the Commission regarding whether postage stamp or locational-based pricing will be confirmed/adopted for new grid investments. The Transmission Pricing Methodology Guidelines are regarded by the Commission as provisional in this regard. In the event that postage stamp pricing is confirmed, the cost of new investments will be allocated to parties regardless of their location.⁵⁷ This means that some parties will pay 'too much' per unit of capacity, and others will pay 'too little' relative to the theoretically efficient price.
175. This creates a free rider problem when TA providers are unable to contract with parties receiving lower transmission charges as a result of the TA investment.⁵⁸ If location-based grid charges, levied at the LRMC of grid expansion, were adopted, this free rider problem would not exist.

⁵⁵ Leaving decisions about lumpy transmission investments as late as possible would be desirable with or without TAs.

⁵⁶ "Free rider" issues arise when one party can gain the benefits of other parties' investments without paying for those investments, and there is no practical way for investors to withhold the benefits of investments from other parties.

⁵⁷ The postage stamp approach spreads transmission charges to parties in proportion to their share of peak demand, and the rate is set to collect enough revenue to cover transmission costs rather than to signal the LRMC of grid expansion.

⁵⁸ The free rider problem only exists insofar as the benefits are insufficient for parties to invest in TAs that have positive net benefits. It would not be seen as a problem that the investor could not gain *all* the benefits of the investment.

4.3.1 Arguments for procurement

176. Some TA providers face incentives to invest in demand reduction or local generation to reduce or delay transmission charges. If transmission charges are not location-based and not levied at rates equal to the LRMC of grid expansion (i.e. the cost is spread across the country), then some of the savings in transmission charges are shared with other parties
177. In theory, TA providers could negotiate with the beneficiaries of their investment (i.e. with all parties receiving lower transmission charges and/or lower nodal prices) but in practice, the costs involved in negotiating with multiple parties will mean many TAs that have net positive industry benefits will not eventuate. This is likely to preclude most investments with multiple beneficiaries, i.e. most core grid investments and some on the radial grid.
178. For example, consider a manufacturer in Auckland able to install energy-efficiency technology to reduce demand from 10 MW to 8 MW during demand peaks for Auckland. This will benefit all peak demand consumers in Auckland by reducing (albeit slightly) the need for grid reliability investment and by reducing nodal prices. However the benefit that the manufacturer can receive is limited to the charges it has saved on 2 MW of transmission capacity, and lower electricity purchase costs (of purchasing only 8 MW, and potentially at a lower price).
179. The Commission believes similar free rider problems may arise in regard to voluntary transmission investment. The Rules address these problems by providing regulated revenue for *all* grid investments approved by the Commission using the GIT. Although the options in this paper limit TA procurement to reliability situations, rather than all grid investment proposals, they go some way to evening up 'the playing field' that is currently tilted in favour of grid investment.
180. Further detail on the nature of the free rider problem for both nodal prices and transmission charges is provided in appendix 3. This appendix also proposes a series of tests that could be used to attempt to ensure that TA procurement only occurs where a free rider issue arises.

4.3.2 Counter arguments

181. The free rider problem in regard to transmission charges arises because of the practical difficulties with implementing efficient transmission pricing, which would require location-based charges levied at LRMC rates. In principle it seems problematic to procure TAs to overcome practical problems with other policy instruments (in this case transmission pricing instruments), especially when there are serious 'slippery slope' risks to consider. These issues need to be considered by the Commission in determining which pricing methodology to adopt.

4.3.3 Conclusion

182. The Commission believes 'free riding' on transmission charges is probably a significant factor undermining incentives for investment in TAs. While in general it can be sensible to introduce policies to try to overcome practical limitations with other policy instruments (in this case transmission pricing), this depends very much on the details of the policy.

<p><i>Q8: Do submitters agree with the assessment of free rider problems in regard to transmission charges? Why or why not?</i></p>

4.4 Free Riding on Nodal Prices

4.4.1 Arguments for procurement

183. For a DSE, one aim of any TA investment will be to reduce nodal prices at times of transmission constraint. However the DSE cannot prevent other demand-side parties paying the same nodal prices from sharing (or free riding on) this benefit. This is a significant issue for transmission because the binary nature of transmission constraints means that small changes in demand for transmission can have very large effects on nodal prices.⁵⁹
184. Some parties also argue that nodal prices collapse in response to generation investment, because they are 'large and lumpy' like transmission investments.⁶⁰ Hence an investor hoping to capture a high price collapses the price with its investment. The investor may then be unable to earn a commercial return on its investment, and TA investments may not occur even though they produce positive net market benefits.

4.4.2 Counter arguments

185. The counter argument is that generation TAs can avoid the free rider problem by adopting offer strategies that avoid nodal price collapse,⁶¹ and/or contracting strategies that capture the benefits of the nodal price reduction.
186. Moreover, although there are economies of scale in generation, the capacity expansion involved with grid investment is far greater than would be achieved with optimally-sized generation investments. Further, generators may be able to make smaller-scale investments to avoid nodal price collapse.

4.4.3 Conclusion

187. The Commission believes free riding on nodal pricing is primarily an issue for load TAs, and perhaps for peaking generation (see the discussion in section 4.5.5). The Commission believes most generators can use their offer strategies to avoid nodal price collapse during periods when the transmission grid would be constrained without their energy.

<p><i>Q9: Do submitters agree with the assessment of free rider problems in regard to nodal pricing? Why or why not?</i></p>
--

4.5 Other Nodal Pricing Deficiencies

188. A number of other reasons have been proposed as to why nodal prices may not provide adequate signals for investment in TAs:
- Nodal pricing signals are too short term to be useful;
 - Nodal prices do not reflect VOLL when supply interruptions occur;
 - Nodal prices do not reflect the full marginal costs of electricity because ancillary services are procured outside market arrangements;
 - Nodal prices may be distorted by the allocation of loss and constraint rentals;

⁵⁹ The binary nature of the problem refers to the fact that transmission constraints are either binding or not binding. This differs from other industries where economic constraints are not so 'hard edged.'

⁶⁰ For a discussion of these issues, See *Transmission Market Design*, William W. Hogan, Center for Business and Government, Harvard University, Texas A&M Conference Paper, (4 April 2003).

⁶¹ This is because it will generally not be commercially viable for another large generator to enter the market until sufficient load growth occurs. Note that generators could go beyond "averting nodal price collapse" to exercise market power.

- e. Nodal prices may be constrained by implicit price caps and do not rise to VOLL when load is curtailed involuntarily;
- f. Generators exercise market power temporarily when the grid is congested; and
- g. The effectiveness of nodal prices may be undermined by investor uncertainty about the regulatory environment, particularly in regard to the GIT.

189. Each of the above issues is discussed in this section of the paper.

4.5.1 The short-term nature of nodal pricing

Arguments for procurement

- 190. Nodal pricing provides very short-term price signals, leaving investors making long-term investment decisions reliant on long-term price forecasts, which are difficult to produce accurately or with a high degree of confidence.
- 191. Energy and transmission hedge products may assist by providing longer-term price signals, but they will need to be sufficiently long term to provide confidence for an investor.
- 192. Lack of good information regarding future prices, due to difficulties forecasting nodal prices and lack of suitable long-term hedge instruments, may make it difficult for TA investors to make timely decisions. If long-term forecasts fluctuate considerably from year-to-year, a consistent trend may not develop until it is too late for investors to invest to avoid high prices and excessive use of high-cost sources of energy. Some generators appear to have mitigated this long-term risk through vertical integration.
- 193. This price uncertainty results in higher economic costs for investors, or at least increases the premium they require to undertake investment. Procuring TAs reduces the risk margin required by investors by transferring the risk of inefficient investment to consumers.

Counter arguments

- 194. Prices in many markets for goods and services are of a short-term nature. Participants in markets develop forecasting models and hedging arrangements (including vertical integration) to assist with managing the associated risk. The uncertainty about future prices reflects the underlying uncertainty about factors such as the future cost and availability of fuels and unexpected changes in demand and technology. In many cases, the cost of reducing uncertainty may outweigh the benefits.
- 195. Further reforms to the markets for energy and transmission hedges should lead to significant improvements in the availability and quality of forecast price information. As the Commission is currently reviewing hedge market arrangements, it would be premature to make decisions based on the current situation.
- 196. Vertical integration helps generators manage risks around the short-term nature of nodal price signals. To the extent their generation and retail portfolios match, nodal price signals have little impact as investment signals. Moreover, a significantly greater understanding of the expected performance of transmission assets provided by the new part F arrangements will also assist even if transmission hedges are not developed.

Conclusion

197. The need to transform short-term signals into long-term forecasts (commensurate with asset lives for instance) is not unique to the electricity industry. The development of forecasting models and hedging tools can assist with this.
198. The Commission does not believe that the short-term nature of nodal pricing is a significant problem undermining incentives for TA investment.

4.5.2 Nodal pricing during supply interruptions

Arguments for procurement

199. Proponents of TA procurement argue that nodal prices should reflect VOLL when supply interruptions occur. This does not occur currently, as final prices for the market are calculated by relaxing constraints to remove infeasibilities. This undermines commercial returns to peaking generators, as they rely on very high prices for very short dispatch runs to make their projects commercially viable.

Counter arguments

200. Opponents of this view argue that the costs of supply interruption caused by insufficient generation in a region are built into nodal prices indirectly. As parties' expectations of supply interruptions increase, the cost of supply at that point will increase, as is regularly seen in constrained regions.
201. It is also argued that the key issue is actually whether such prices will be allowed to send the appropriate investment signal or whether regulatory pressure will effectively cap such prices and mute the price signal.

Conclusion

202. The Commission agrees the lack of VOLL pricing reduces commercial incentives for TA investment, but believes this problem may be better addressed through energy market developments than through procurement of TAs.

4.5.3 The cost of ancillary services

Arguments for procurement

203. Proponents of TA procurement argue that nodal prices are incomplete because they do not include the cost of ancillary services purchased outside market arrangements (e.g. those procured through separate contracts, such as the zone 1 reactive power arrangements).⁶² Responses to incomplete nodal prices cannot therefore be optimal.

Counter arguments

204. The exclusion of outside-market ancillary service purchases from the nodal price is irrelevant provided the allocation mechanism for these costs appropriately signals the need for new investment. For example, in the case of the zone 1 reactive power arrangements, the cost allocation at least attempts to do this.

⁶² However, note that some aspects of reliability are reflected in nodal prices, such as the cost of instantaneous reserves (IR) purchased to cover for generation contingencies.

Conclusion

205. The Commission believes this argument is not sufficient to justify regulated procurement of TAs, as the allocation of ancillary service costs is likely to provide good enough price signals, particularly given that these costs are only a small proportion of total energy costs.

4.5.4 Allocation of loss and constraint rentals

206. The allocation of loss and constraint rentals may undermine or distort nodal pricing signals if the amounts paid are correlated with energy injections and offtakes.⁶³ Currently Transpower rebates rentals to parties in proportion to their transmission charges, which in turn are based on measures of peak load for consumers and measures of peak injections for generators (in the case of HVDC charges).
207. In general, the Commission believes decisions about the allocation of loss and constraint rentals should be determined in conjunction with decisions about transmission pricing and FTRs. It seems inappropriate to procure TAs to correct deficiencies in the allocation of rentals when the Commission can resolve that issue directly.

4.5.5 Implicit price caps and market power

Arguments for procurement

208. Regulatory intervention such as the investment in, and operation of, Whirinaki power station, may have the outcome of creating implicit caps on nodal prices. For example, Whirinaki may be activated in response to high or volatile nodal prices, effectively creating a price cap.⁶⁴ The impact of Whirinaki will be influenced by the location of the proposed transmission investment, which may be important for investment in the Hawke's Bay but less important elsewhere.
209. More generally, investors in peaking plant may have concerns that the prices necessary to cover their capital costs may be politically unacceptable and limit their ability to recover full capital costs within their required payback timeframes. For example, Open Cycle Gas Turbines (OCGTs) that may be efficient to ensure reliability of supply are designed to run for a few hours per year, and need to charge very high prices to recover their capital costs.
210. The normal market solution would be for the beneficiaries of peaking plant (the load customers in the region) to contract with the peaking plant via an option contract, structured as a contract-for-differences (CfD) against nodal prices at the relevant GXP. This would provide the peaking generator with certainty of income and provide customers with certainty about prices.
211. The problem with the option contract approach, however, is that it brings low prices to all consumers, not just to those holding option contracts. This creates a free rider problem that would not exist if implicit price caps did not exist, as they could then recover all of their costs from the spot market.

Counter arguments

212. The counter argument is that generators that do not have load within constrained regions can exercise market power when the grid becomes congested. If this is the case, then far from discouraging peaking generation, nodal prices encourage too much.

⁶³ Rentals are currently paid to Transpower, who rebates them to distributors. Distributors may rebate them to retailers, who in turn may rebate them to consumers.

⁶⁴ Operation of Whirinaki does not itself cap prices, but it will tend to reduce price volatility. Whirinaki is intended to provide both reserve generation capacity and grid capacity.

Conclusion

213. The impact of interventions, such as offers from the Whirinaki power station, reflect Government policy intentions. The Commission believes that in principle it should not use transmission policies to offset the impact of other policies; rather the original policy should be modified if it is not appropriate.
214. The Commission believes the issue of implicit price caps arising from the perceived unacceptability of temporarily high spot prices may have some merit, and should be considered when determining whether to procure TAs.

4.5.6 Regulatory uncertainty

Arguments for procurement

215. TA investments – particularly generation investments – often involve large sunk investments for which parties recover costs over multiple time periods. For these investors, uncertainty about the regulatory environment, for example in regard to hedge market or nodal pricing arrangements, can undermine the effectiveness of nodal price signals.
216. This is particularly important in regard to the regulatory arrangements for deciding grid investment, such as the SOO and the GIT, because grid investment affects nodal prices. For example, investors seeking to install generation capacity downstream of grid constraints are exposed to the risk the Commission will change the methodology for the GIT, or apply the GIT in unexpected ways.⁶⁵ Directly procuring TAs in the same manner as grid investment is procured overcomes this problem and is necessary to achieve a level playing field with grid investment.⁶⁶

Counter arguments

217. The counter argument is that the SOO and GIT reduce regulatory uncertainty by providing investors with transparent, predictable, and credible signals about future grid upgrade proposals. This should be viewed as an improvement over the previous approach where grid investment decisions were left to voluntary contracting between Transpower and its customers, which were beset by free rider problems.

Conclusion

218. The Commission believes regulatory uncertainty is best addressed by administering grid investment decision processes in transparent and predictable ways. It does not believe regulatory uncertainty provides a sound reason for procuring TAs.

4.5.7 Overall conclusion on nodal pricing deficiencies

219. Overall the Commission does not consider the nodal pricing deficiencies, on their own, justify regulatory intervention in TA investment decision-making processes. There are some significant concerns, for example in regard to the short-term nature of nodal prices and the lack of VOLL pricing during supply interruptions, but each of these can be addressed by other regulatory measures.

⁶⁵ For example, some jurisdictions place a stronger emphasis on consumer benefits. Regulatory risk may also arise from rule changes that relax grid constraints (e.g. the development of capacity reserves), or from discretionary changes in system operation.

⁶⁶ Note that, as discussed in section 3, procurement does not necessarily mean that funding is provided.

Q10: Do submitters agree with the assessment of the nodal pricing deficiency issues? Why or why not?

4.6 'Slippery Slope' Risks

4.6.1 Why do 'slippery slope' risks occur in general?

220. The 'slippery slope' risks associated with a regulatory intervention arise from two main factors:
- a. *Undermined incentives.* This occurs when the initial intervention shifts responsibility from market participants to regulatory authorities, in ways that undermine incentives for market participants to provide the outcomes sought by the intervention; and
 - b. *Poor quality information.* Poor quality information occurs because regulators are typically several steps removed from 'the action', making it difficult to target interventions to the source of the problem. This results in the regulatory authority having inadequate or ineffective instruments to deal with adverse outcomes.
221. In this situation, the inadequacy of the instruments results in further regulatory (but still inadequate) measures being adopted in urgency in response to unanticipated adverse outcomes, further over-reaching the regulatory authority's ability to achieve policy outcomes.
222. The best way to mitigate 'slippery slope' problems is to target interventions at the source of a market problem, and adopt instruments that utilise the incentives and information of market participants in ways that are effective and robust to all likely events. In many cases it is not possible to design effective and robust instruments, and sometimes the costs of market inefficiencies are not large enough to justify the costs and risks of regulatory intervention.
223. Having said that, markets and economic activity require sound regulatory foundations to flourish. There are many examples of effective and robust interventions, such as the limited liability status of corporations, and the wholesale electricity market itself. Within this context, it is not relevant to be pro-market or pro-regulation – what is needed is the right instruments to facilitate efficient economic exchange.

4.6.2 Arguments against procurement

224. Concern has been raised about the unintended consequences of the procurement of TAs, centering on concerns about intrusion into the market, and delays to making grid investment decisions.
225. In particular, there is concern that procuring TAs may distort market-based investment decisions, and lead the Commission down a 'slippery slope' of increasing interference in generator investment decisions, potentially leading to a situation where regulators gain virtually full control over generation investment decisions and the operation of generators in the wholesale market.
226. These concerns are heightened by the long 'stringy' nature of the New Zealand power system, which is likely to make many new generation proposals eligible for consideration for procurement. The longitudinal nature of New Zealand's grid means most generation investment decisions carry significant reliability implications and, therefore, affect grid investment decisions. This brings the decentralised approach to generation investment 'hard up against' the central decision-making framework for grid investment.

227. While TA procurement may appear to provide an efficient outcome on a one-off project basis, the overall detrimental effect on the competitive sector of the electricity market could be serious.
228. In particular, a regulatory decision that incentivises investment in a generation TA in Auckland, for example, immediately changes the investment climate for all generation investment decisions, both in Auckland and outside Auckland. It does this by creating winners and losers, such that generator investors have incentives to attempt to 'game' the TA procurement process. For example, generators are likely to withhold their investments in order to obtain regulatory funding for their investment. It also creates risks for other investors as their investments could be stranded by procured TA investments.
229. According to this view, these kinds of concerns could 'chill' market-based investments, reinforcing preconceptions that the market cannot be relied on to deliver reliability of supply, and creating pressure for more extensive regulatory determination of generation investment.

4.6.3 The argument for procurement

230. As indicated in section 4.6.1, 'slippery slope' risks should be manageable provided TA procurement is targeted at the source of the market inefficiency, and utilises the incentives and information of market participants in ways that are effective and robust to all likely events. To the extent that the instruments do not utilise market incentives and information, 'slippery slope' risks are mitigated by restricting the focus of the TA procurement regime (in this case to dealing with grid reliability investments), and by adopting additional tests to target the application of the regime.

4.6.4 Conclusion

231. The Commission believes that concerns about the potential for increasing regulatory intervention in market-based investment decision processes have some validity. The detailed design of any TA procurement regime is therefore very important. These issues are discussed further in section 5.2.4.

4.7 Summary of Issues

232. A summary of the issues as a whole, and how they relate to each of the five main options is included in the evaluation in section 5.

5. Evaluation of Options

5.1 Evaluation Criteria

233. As stated in section 3, the principles adopted for designing procurement policies and procedures are to:
- a. Promote a level playing field between grid investments and TAs, and between alternative types of TAs, so that the lowest cost options are procured consistent with grid reliability standards;
 - b. Maximise opportunities for innovation in the provision of TAs to reduce the costs of electricity over the long run;
 - c. Provide reasonable certainty that TA investments will occur within required timeframes (and will operate when required);
 - d. Promote certainty for investment in the grid and investment by grid users;
 - e. Minimise adverse effects on the competitive sectors of the market (i.e. minimise 'slippery slope' risks);
 - f. Be consistent with the GIT and other transmission and security of supply work streams; and
 - g. Minimise administration and compliance costs.
234. This section evaluates the five options specified in section 3 against the criteria outlined above.

5.2 Evaluation against Criteria

5.2.1 Level playing field

235. A concern with the market response option is that it does not address the free rider or commitment problems and, therefore, does not allow potentially more efficient TA options to compete effectively with grid investment in the GIT decision-making process. This may lead to substantial uneconomic over-investment in grid assets.
236. All of the procurement options address the commitment problem and, partially, the free rider problem. Free rider problems are only partially addressed because TA procurement is restricted to that necessary to achieve reliability of supply, whereas all approved grid investments will receive regulated funding.

5.2.2 Maximise innovation opportunities

237. The market response option maximises innovation opportunities for commercially viable TAs, as TA providers are free to contract with whomever they like. However, innovation is likely to be undermined by the presence of free rider problems which undermine the viability of many projects, particularly demand-side projects.
238. The DP options facilitate innovation opportunities because TA providers will be free to contract with multiple DSEs, but these gains are limited to the extent that the regime targets substitutes for grid reliability investments.
239. The CP options perform poorly on this criterion because a single body would be responsible for determining which TAs will be procured, which is generally inimical to innovation. Having said that, using competitive tenders to even up the 'playing field' for demand-side TAs is positive for innovation because the opportunity for innovation on the demand-side has been limited by the sometimes fragmented incentives provided by current (and previous) market

and regulatory arrangements. To date, the opportunity for innovation may have had a supply-side bias.

240. The minimal CP option performs less poorly than the universal CP option because regulatory tests would be employed in the former to limit the scope of the single decision-maker to procuring only TAs experiencing significant free rider problems. Note that opportunities for innovation would be even greater under the minimal CP option if generator TAs were not procured, as suggested in section 3.9.⁶⁷

5.2.3 Promote investment and operational certainty in TAs

241. The primary disadvantage of the market response option is that it does not provide certainty (equivalent to approving transmission investment) for the Commission that efficient TAs will eventuate. This is a serious concern to the Commission, such that it is the primary reason for considering other options.
242. All procurement options to varying degrees provide the Commission with a greater degree of confidence that TAs will emerge and thus give the Commission greater confidence to delay transmission investments when doing so produces net economic benefits for New Zealand.
243. The CP options provide high levels of certainty, as the System Operator would contract with TA providers and monitor their capacity and operational activities directly. The RCC option appears to provide much less certainty than the other procurement options because it relies on financial penalties on DSEs that would not be determined until after real-time, which is too late for the Commission to organise other TAs if those expected do not eventuate. The limited DP option is intended to overcome this problem but preserve as far as possible the innovation advantages of the RCC approach.
244. In terms of operational certainty, work undertaken in the development of the CP options (see appendix 2 for more details) suggests that, once TAs are in place, they receive sufficient incentives (from the market) to operate at the required times.

5.2.4 Promote certainty for investment in the grid and investment by grid users

245. The previous criterion considered the extent to which each option provided the Commission with reasonable certainty that promised TAs would eventuate within required timeframes. In contrast, the criterion in this section requires the Commission to consider how each option affects regulatory uncertainty, which in turn may affect certainty for grid investment and investment by grid users (this was discussed in section 4.5.6).
246. The Commission believes reducing regulatory uncertainty for grid users depends largely on it exercising its grid investment decision-making powers in transparent and predictable ways. In general regulatory uncertainty will be greater for options that require longer implementation timeframes or that involve more complex regulatory decision-making processes.
247. In this regard, the market response option performs best on this criterion because it is simple and can be implemented immediately. The CP options perform better than the DP options on this criterion, as the latter options would take longer to implement, involve fairly significant implications for all DSEs and all generators, and may involve more complicated compliance regimes.

⁶⁷ Though it should be noted that work to date suggests that the extent to which demand-side options will be able to defer or replace transmission investment is expected to be less than with supply-side options.

5.2.5 Minimise 'slippery slope' risks

248. The primary outcome of the market response option is that it would probably result in the Commission approving grid investments, which would address reliability risks for the foreseeable future, without the risk of further regulatory intervention. Grid investment would of course significantly influence generation (and perhaps load) location decisions, but it would avoid a central body 'picking winners' among specific proposals.
249. The primary disadvantage of all the procurement options is increasing regulatory involvement in investment decision-making processes, thus eroding the benefits of market-based investment processes ('the slippery slope'). This risk exists under both the CP and DP options, although it is a more significant concern for the CP options. The Commission believes that 'slippery slope' concerns are manageable under the minimal CP option and, to a greater degree, under the limited DP option. The Commission notes that the minimal CP option would perform even better on this criterion if generator TAs were not procured, as suggested in section 3.9.

Targeting the source of the problem

250. The DP options target the source of the problem, which, in this case, is that beneficiaries of TA investments can avoid contributing to TA costs. Both DP options provide mechanisms for requiring the beneficiaries of TA investment to contribute to the costs of the investment (although the Commission has reservations that this can be achieved in practice, as the allocation of regional capacity obligations may involve problems similar to those encountered with location-based transmission pricing).
251. The DP options target assistance to TAs that require the least amount of assistance, rather than to those experiencing the most significant free rider problems. This is because DSEs have strong incentives to implement contracting processes that pay TAs the minimum needed to get them to invest. Commercially viable TAs, and near commercially viable TAs, will presumably bid the lowest prices to DSEs.
252. In contrast, under both CP options, costs are likely to be recovered using the transmission pricing methodology. This means that, under the 'postage stamp' methodology, the CP options do not target cost-recovery to the beneficiaries of TA investments. Rather, any TA procurement costs are recovered on the same national spread basis as transmission costs. On the other hand, TAs will be selected for procurement on the basis of their net market benefits in the GIT, and so the CP options are more likely to target assistance to TAs experiencing significant 'free rider' problems. To the extent that the tender process takes into account the price of the TA, the CP process, like the DP process, will prefer options that are closer to commercial viability.

Utilising incentives and information

253. The second requirement for robustness to 'slippery slope' risks is to create instruments, particularly new property rights, which utilise the incentives and information of market participants to determine when, what, and how new generation and demand response capacity should enter the market.
254. The DP options would appear to satisfy this test because they create a new instrument (i.e. capacity contracts) that can be traded on secondary markets, the price of which will reflect market participants' views of the need for new capacity. If participants believe the central agency has over-forecasted load growth, then they will offer low prices for capacity contracts as there is little risk of breaching their capacity obligations. In theory, at least, the DP options

also leave it to market participants to decide how to meet their capacity obligations (i.e. through demand or supply measures) and what technology to adopt.

255. The CP options also satisfy this test because they utilise competitive tender processes for selecting the best approach for addressing reliability needs. For example, tender prices will be very high if TAs are not a competitive option for grid reliability investment, and this will cause the Commission to review its application of the GIT to determine whether grid investment is the more efficient option.
256. Moreover, the GIT process is aimed at ensuring all TA investment decisions are made with maximum available information about how such investments might affect grid investment decisions.
257. The tender process approximates a market outcome for grid reliability investment by allowing competitors to Transpower to be considered in the grid investment decision process. The argument that generators and other TAs will not invest (in response to market conditions) outside of the tender process seems very unlikely because making such investments would pre-empt the tender, removing the need to hold the tender or at least reducing the volume of the tender. This argument assumes generator TAs value pre-emption more than the prospect of securing some regulated funding through tender processes. Certainly, the GIT will treat such investments as sunk costs and, therefore, they will show up as highly economic.
258. In practice, the universal CP option would immediately and significantly increase regulatory intervention in the wholesale electricity market because many of the operational decisions of generator TAs would be centrally determined. Moreover, the actions of central agencies would increasingly influence spot market prices over time as an increasing proportion of generation investment is procured as TAs to meet load growth. There are also significant problems with distinguishing between new capacity on the one hand and existing and retiring capacity on the other hand.⁶⁸ These effects are limited, however, by the intention to procure TAs only to meet reliability needs, rather than to remove grid constraints.
259. The minimal CP option removes the worst aspects of the universal CP option in regard to 'slippery slope' risks. It does this by not imposing maximum prices on energy offers by generator TAs, imposing fewer operational requirements on generator TAs, and using tests to target assistance to TAs that would not otherwise occur. Although this option also encounters problems with distinguishing between new, existing, and retired capacity, these problems are also mitigated by the restricted focus of the TA regime on reliability investments.
260. The DP options also face some 'slippery slope' risks because the risk of TAs not meeting their obligations when called upon to do so increases with the number of parties involved in contracting TAs and with the use of more innovative TAs. Whereas the CP options rely on a single body to contract and monitor TAs, the DP options involve multiple parties (i.e. DSEs) with, at times, conflicting commercial incentives. This may leave the DP options exposed to 'slippery slope' risks.

⁶⁸ This is a significant issue in the PJM market in the United States, where PJM sometimes have to contract with "retiring" plant until they can build a transmission line. Failure to resolve these issues could lead to significant impact on the wholesale market.

Conclusions on 'slippery slope' risks

261. The Commission believes the DP options are theoretically more robust to 'slippery slope' risks than the minimal CP option. This is because they create a new instrument that can be traded on secondary markets (providing better quality information to the Commission), and they decentralise the TA provision decisions to DSEs - keeping the central authorities further removed from market investment decisions.
262. Overall, the Commission believes the 'slippery slope' risks with the minimal CP option are manageable, because the GIT and competitive tenders are utilised to preserve commercial incentives for investment in ordinary generation. Generators willing to commit to such investments in regions with reliability problems can pre-empt the GIT and the tender. The tender also provides the Commission with the information it needs to trade-off proposals for grid reliability investment and TA investment. Restricting the regime to reliability investments also assists with limiting 'slippery slope' risks.

Q11: Do submitters agree with the general framework regarding 'slippery slope' risks outlined in section 4.6.1, and the discussion here? If not, what alternative framework should the Commission consider? Do submitters agree that 'slippery slope' risks depend greatly on the details of the TA procurement regime? Do submitters believe that these risks can be managed under the minimal CP and limited DP options? Why, or why not?

5.2.6 Consistency with the GIT and other work streams

263. All options are considered to be consistent with the grid investment decision-making process, with the Commission's approach to grid reliability standards, and with the proposed approaches to transmission service definitions and measures and proposed benchmark agreements.
264. The CP options are consistent with either postage stamp or location-based approaches to transmission pricing because TA providers will impute these factors into the prices they submit in TA tenders. As tender costs can easily be recovered in the same manner as grid investment costs, there is no incentive on DSEs to favour grid investment over TA investment, or vice versa.
265. The DP options are consistent with location-based grid charges because the allocation of capacity obligations will be regional (i.e. location-based). At this stage the Commission believes many of the practical difficulties with adopting location-based charges may also occur in determining regional capacity allocations under the DP options.
266. The DP options may not be consistent with postage stamp pricing for new grid investment. This is because TA costs would be borne on a regional basis whereas grid investment costs would be spread nationally. The Commission's decisions between grid investment and TAs would carry significant distributional implications, and become more controversial than should be necessary. It could also lead the Commission into considering distributional issues rather than just net economic benefits.

5.2.7 Minimise administration and compliance (A&C) costs

267. The market response option has the advantages of not increasing regulation, and therefore not affecting A&C costs. All of the procurement options involve some level of A&C costs:
- a. For the universal CP option, significant costs are likely to arise with setting and administering pricing and operational constraints, and with

conducting tenders. The universal application of this approach to any TA exacerbates these costs;

- b. For the minimal CP option, significant costs are likely to arise with setting and administering the regulatory tests to determine which TAs are eligible for tendering;
- c. For the limited DP option, significant costs are likely to arise with setting and administering the capacity obligations and for administering the verification regime. These costs are higher than the CP options because of the greater number of parties involved and the potential for dispute; and
- d. For the RCC option significant costs are likely to arise with setting and administering the financial penalty regime. These costs are also likely to be larger than under the CP options because of the multiple number of parties involved, etc. In contrast to (c) above, there may be significant complications with capacity reconciliation, which would increase the administration and compliance costs of the RCC option.

5.2.8 Conclusions on the qualitative assessment

268. It appears the minimal CP option and the limited DP option may be preferable to the other options. This is based on the view that both options involve lower 'slippery slope' risks than the universal CP option, and both give the Commission greater confidence that TAs will eventuate within required timeframes than is likely to occur under the RCC option or the market response option.
269. However, the Commission has not determined a preferred option. Rather it has retained an open mind as to the likely solution, and seeks input from submitters to assist with this decision.

Q12: Which option(s) do submitters prefer? Why? Do submitters agree with the Commission's assessment of the various options against the decision criteria? Why, or why not? Would your views change if location-based transmission charges were adopted, instead of the current proposal to adopt postage stamp charges?

5.3 Cost-Benefit Assessment

270. A complete cost-benefit analysis requires estimating the following:
 - The avoided costs of transmission investment including capital and operating costs;
 - The value or cost of any quality differences between transmission and TAs, such as transmission losses, availability, and any improved trade-off between grid reliability and cost;
 - The option value of TAs due to the delay of transmission investment;
 - The administrative costs of procurement;
 - The cost of procuring TAs;
 - Any costs relating to sub-optimal procurement, such as procurement of the wrong type of TAs and procuring too many TAs; and
 - The impact on dynamic efficiency, such as the impact on investment in new generation.
271. A detailed discussion of these elements of the cost-benefit analysis is set out below. However, the Commission considers that insufficient information is currently available to robustly estimate net benefits for any or all procurement

options compared to the market response option. Therefore, the Commission has not estimated the net benefits on a quantitative basis for any of the procurement options. The Commission is seeking views of submitters on the cost items set out in the previous paragraph.

5.3.1 Avoided cost of transmission

272. The Commission has estimated the benefits from the avoided cost of transmission investment in the Auckland/Northland region to provide an indication of gross benefits (benefits prior to taking account of costs of TAs etc.) from procuring transmission alternatives. Procuring TAs increases the confidence that TAs will materialise, thereby avoiding the need to commit to inefficient transmission investments.

273. Based on data from a study by SKM, the Commission has estimated the benefits from a one-year deferral of the grid upgrade would be \$35 million.⁶⁹ This level of annual benefits amounts to a net present value of close to \$250 million over 10 years. Clearly, the benefit across the whole of New Zealand is likely to be higher than this estimate. The calculation of gross benefits illustrates that there are significant potential benefits from procuring TAs.⁷⁰

5.3.2 Quality differences between TAs and transmission

274. The magnitude of transmission losses is a key difference between transmission and TA investments. Expanding grid capacity will result in reduced transmission losses. TAs will also result in some reduction in transmission losses, but this reduction will be limited to the times when transmission alternatives are operating. For example, if a TA only operates when transmission security limits are reached, then losses will only be reduced at these times.

275. Transmission assets often have a higher availability than generation or demand-side assets. However, transmission investments tend to be few in number but large in scale. Consequently there is a higher probability that a single transmission outage event will lead to a loss of supply (unserved energy). In comparison, demand-side TAs, and to a lesser extent generation TAs, are often smaller in scale and simultaneous failure of a number of elements is required before there is a loss of supply.⁷¹

276. Furthermore, due to their scalability, TAs enable the Commission to make better trade-offs between grid reliability and investment. Transmission investment is likely to be "large and lumpy" relative to TAs. Given large and lumpy transmission investment proposals, the Commission may have to trade off significant supply risks with the large cost of grid investment. However, investment in TAs may enable the System Operator (in its procurement role) to make worthwhile improvements in grid security for a smaller incremental cost.

⁶⁹ Sinclair Knight Merz, *Alternatives to Transmission for Supply of Auckland's Growing Electricity Demand* (26 October 2004).

⁷⁰ As noted in paragraph 8, the GIT includes "competition benefits," which allows the competitive benefits of removing constraints to be taken into account in the analysis of transmission versus TA investment.

⁷¹ For further information, see PB Associates, *Example of the application of an economic grid reliability standard* (November 2004). This report is in Appendix 5 of *Grid Reliability Standards consultation paper* (December 2004) available at <http://www.electricitycommission.govt.nz/opdev/transmis/pdfsconsultation/pdfsgrs/grs-consultation-paper-with-appendices.pdf>.

5.3.3 Option value of delayed transmission investment

277. Procuring TAs enables decisions on transmission investment to be deferred. The delay has an option value: the delay in taking a decision on the large sunk cost investment in transmission will enable new information to be taken into account. For example, the delay will allow decision-makers to take account of new information on demand growth and changes in technology.

5.3.4 Cost of procuring TAs

278. The provision of transmission alternatives incurs resource costs. These costs need to be taken into account in order to determine the net benefits from substituting TAs for transmission. TAs provide benefits both in terms of avoided transmission investment, and provision of energy/avoided demand. Therefore, providers of TAs will allow for these benefits when offering to provide TAs. The relevant cost for the cost-benefit analysis is the net cost, or the cost after allowing for the benefits from generation/avoided demand.

279. It is not straightforward to estimate the net cost of TAs as the generation or demand avoidance benefits from particular TA options have not been analysed. The SKM report identifies the cost of a range of TA options but does not attempt to estimate the net cost for these TAs.

5.3.5 Cost of sub-optimal procurement

280. Sub-optimal decisions could occur in the central procurement option⁷² when the System Operator selects a TA investment that is less optimal than what would have been selected by the market. Three types of possible errors have been identified:

- a) Unnecessary procurement;
- b) Procuring the wrong type of TA; and
- c) Excess Procurement.

Unnecessary procurement

281. This is where the System Operator procures a TA that would have emerged without funding. For example a TA investment that was viable without additional funding may seek additional income via a TA procurement process by either overstating its costs or understating the benefits it can capture.

282. The result of this particular error is a wealth transfer between those who pay for the TA and the providers. Economic costs also result from costs incurred by firms seeking such benefits (including unsuccessful applications) beyond expected administration costs. This cost will occur even where the Commission is successful in distinguishing between TAs that would have emerged from those that require funding, as it results from firms *seeking to capture* rather than actually gaining these benefits. From the firm's perspective it will consider the potential benefits from receiving funding compared to its own cost of submitting bids. From a national perspective all time and costs involved in attempting to game the system are resource costs. Wasteful expenditure arising from firms seeking to capture the gains from unnecessary procurement could, over time, potentially equal the total amount of unnecessary procurement. The risk of this outcome can be managed by running an effective tender process.

⁷² Some of these errors could also occur in a decentralised option if the volume of TAs to be procured was set centrally and was incorrect.

Procuring the wrong TA

283. The System Operator has to evaluate a wide range of potential demand-side and generation options over various time periods. It is possible that the System Operator would procure a more expensive TA than the optimal choice of TA. There is also some risk of inefficient procurement of transmission.
284. The potential for this type of error to impose inefficient costs on consumers will be heavily dependent on the nature of the procurement process and the TA contract.

Excess procurement

285. The procurement agency will face strong incentives to ensure sufficient TAs are procured to ensure it can confidently delay any transmission investment. As such it may over-procure TAs.⁷³ It could be argued that the timing of decisions to procure TAs would be the same as for decisions to procure transmission. However, a further issue is whether the procurement of TAs is optimal, i.e. the right amount of TAs for a given outcome. The System Operator (in its procurement role) does not face the same incentives as profit-maximising firms to manage costs. It seems reasonable to assume that the System Operator might over-procure TAs to some extent relative to an efficient provider. Note that the risk also exists (to a greater extent) with regulatory approval of transmission investment.

5.3.6 Dynamic efficiency

286. The 'slippery slope' concerns of increased regulatory intervention (outlined in section 4.6) are the dynamic efficiency losses associated with central procurement, in the event that the procurement becomes increasingly involved in more generation investment decisions.⁷⁴ One hypothesis is that the procurement agency's decisions impact on all generation or load investment decisions, so that market-based investment is undermined, and less optimal investment decisions are made than would occur under a competitive market outcome.
287. In practice, the dynamic efficiency risks will depend on the nature of the procurement arrangement. As discussed in section 4.6, 'slippery slope' risks should be manageable, provided TA procurement is targeted at the source of the market problem, and utilises the incentives and information of market participants in ways that are effective and robust to all likely events. To the extent that the instruments do not utilise market incentives and information, 'slippery slope' risks are mitigated by restricting the focus of the TA procurement regime to dealing only with grid reliability investments, and by adopting additional tests to target the application of the regime.

5.3.7 Differences between the procurement options

288. The discussion above describes the benefits of procurement compared with a market response. This section discusses the differences between procurement options.
289. Both decentralised procurement options are likely to result in lower sub-optimal procurement costs, as the DSEs will have incentives to minimise cost subject to meeting capacity requirements (or avoidance of penalties). They are also likely to allow for greater risk-taking and innovation in the development of TAs. However, decentralised procurement is likely to result in

⁷³ A similar outcome could exist with market driven procurement. The proposed RCC regime has significant penalty costs that may drive DSEs to over-procure TAs / procure them too early.

⁷⁴ In an extreme scenario, all generation investments could become TAs.

higher administration costs, due to the loss of economies of scale in the procurement process relative to the CP options. The RCC approach is likely to result in less certainty for the Commission about the emergence of TAs compared to other forms of procurement (where the amount of capacity is specified) and therefore result in more transmission investment.

Q13: Do submitters agree that the Commission has identified the costs and benefits of procurement options that need to be included in its cost-benefit assessment? Why, or why not?

Q14: Do submitters have any views about the likely value of avoided transmission investment, costs of procuring TAs, benefits or costs relating to quality differences between transmission and TAs, any costs relating to sub-optimal procurement, the option value of delayed transmission investment, and the impact on dynamic efficiency from procurement of TAs?

Q15: Do submitters consider that decentralised procurement is likely to result in lower procurement costs but higher administration costs?

5.4 Assessment against Commission's Objectives and GPS Outcomes

290. Table 5, below, assesses TA procurement against the Commission's principal objectives, the objectives specified in rule 6.3 of section III of part F of the Rules for developing the GIT, and the outcomes specified in the GPS.

291. The market response option is essentially equivalent to doing nothing (though note that it would be likely to involve some information rule changes), and is not therefore considered explicitly in the following assessment.

Q16: Do interested parties agree with the assessment of the procurement options against the Commission's principal objective and the GPS outcomes? Why, or why not?

Table 5: Assessment against Commission objectives and GPS outcomes

Objectives	Response
Act Objectives: under section 172N of the Electricity Act 1992, the principal objectives of the Commission:	
<ul style="list-style-type: none"> To ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and To promote and facilitate the efficient use of electricity. 	<p>All TA procurement arrangements contribute to efficiency by encouraging the development of TAs when these are a more efficient option than grid reliability investments. This ensures that grid reliability investments are only undertaken when net benefits are positive and greater than the net benefits of TAs.</p> <p>TA procurement contributes to environmental sustainability because TAs will usually have lower environmental impact than transmission investments and the procurement of TAs will encourage the development of further TAs and minimise the need for transmission reliability investment.</p> <p>All TA arrangements support the GIT process which in turn promotes and facilitates the efficient use of electricity by ensuring local generation is made available to consumers only where that is a more efficient option than the combination of remote generation and transmission.</p> <p>Furthermore, the minimal CP and limited DP options achieve this objective better than universal CP or market response options by minimising the probability of uneconomic transmission investments being approved.</p>
Part F objectives for developing the GIT (rule 6.3 of section III)	
<ul style="list-style-type: none"> 6.3.1: Promoting economic efficiency (including energy efficiency) in transmission and the wholesale market. 	<p>All TA procurement arrangements promote economic efficiency in transmission and the wholesale market by ensuring investment in local generation occurs only where that is more efficient than the combination of investment in remote generation and transmission.</p> <p>Furthermore, the minimal CP and limited DP options achieve this objective better than the universal CP option, by minimising the probability of uneconomic transmission investments being approved and helping to minimise the risks of dynamic efficiency losses. Minimal CP and limited DP options provide improved static efficiency compared to the RCC approach by increasing certainty about TAs emerging and thereby increasing the amount of transmission investment deferred.</p>
<ul style="list-style-type: none"> 6.3.2: As far as practicable reflecting the interests of end-use customers in ensuring a reliable transmission system having regard to the cost to end-use customers. 	<p>The TA procurement arrangements include the value of unserved energy in calculations of net market benefits of a TA, and so explicitly take into consideration the cost of reliability to end-use customers.</p>

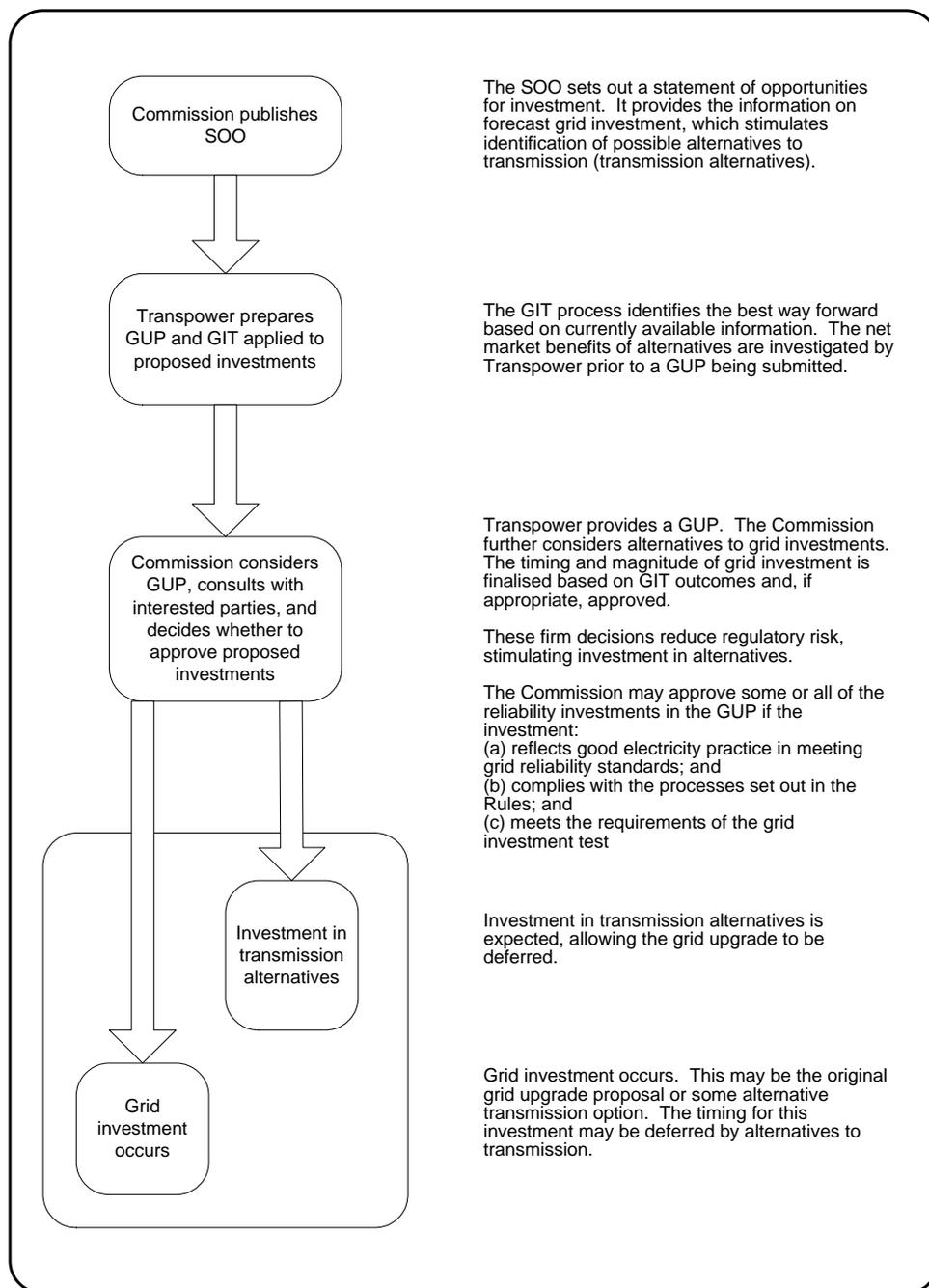
Table 5: Assessment against Commission objectives and GPS outcomes

Objectives	Response
<ul style="list-style-type: none"> 6.3.3: Reflect a reasonable economic assessment of the balance between different levels of reliability and the expected value of energy at risk. 	<p>The centralised TA procurement process, in determining which TAs to fund, includes assessment of reliability investment proposals, taking into account project costs and the value of unserved energy. The DP approaches enable DSEs to make the appropriate trade-offs.</p>
<ul style="list-style-type: none"> 6.3.4: Enabling selection of transmission upgrade options that maximise the total net benefits to those who produce, distribute and consume electricity after taking into account alternatives to transmission. 	<p>All TA procurement arrangements further the selection of transmission upgrade options that maximise the total net benefit to producers, distributors and consumers by enabling TA proposals to compete with transmission investment. This enhances the range of TAs available for consideration.</p>
<ul style="list-style-type: none"> 6.3.5: Promoting certainty for investment in transmission, generation and transmission alternatives and investment contracts. 	<p>The CP options promote certainty for investment in transmission and alternatives to transmission (which includes generation) by providing equal certainty of income for TAs and grid investments. The limited DP option also provides a high level of certainty. The RCC option provides the least certainty of the procurement options, but still greater certainty than the status quo.</p>
<ul style="list-style-type: none"> 6.3.6: Facilitating outcomes acceptable to Transpower and designated transmission customers. 	<p>The GIT should facilitate outcomes acceptable to Transpower and designated transmission customers by providing a transparent and robust methodology for awarding and operating TA contracts.</p>
<p>Assessment against GPS objectives and outcomes</p>	
<ul style="list-style-type: none"> Energy and other resources are used efficiently. 	<p>All TA procurement arrangements promote efficient use of energy and transmission resources by ensuring local generation is made available to consumers only where that is a more efficient option than the combination of remote generation and transmission.</p>
<ul style="list-style-type: none"> Risks (including price risks) relating to security of supply are properly and efficiently managed. 	<p>All TA procurement arrangements include the value of unserved energy in their calculations of net market benefits, which should ensure that transmission capacity is available for generation to meet load.</p>
<ul style="list-style-type: none"> Barriers to competition in electricity are minimised for the long-term benefit of end users. 	<p>All TA procurement arrangements reduce barriers to competition for demand-side participation in the market, thus enhancing long-term benefits to end users.</p>
<ul style="list-style-type: none"> Incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment. 	<p>All TA procurement arrangements enhance incentives for investment in generation, transmission, energy efficiency, and demand-side management by providing a method for procurement of generation, demand-side management and energy efficiency alternatives to transmission investment where such arrangements provide a net benefit to the industry as a whole. The proposed arrangements also remove any potential discrimination between private and public procurement of investment by ensuring both have access to regulated procurement.</p>

Table 5: Assessment against Commission objectives and GPS outcomes

Objectives	Response
<ul style="list-style-type: none"> The full costs of producing and transporting each additional unit of electricity are signalled. 	Not applicable.
<ul style="list-style-type: none"> Delivered electricity costs and prices are subject to sustained downward pressure. 	The GIT, which determines the optimal quantities of transmission and TA investments, includes competition benefits in its calculations of net market benefits, and so should facilitate competition where appropriate.
<ul style="list-style-type: none"> The electricity sector contributes to achieving the Government's climate change objectives by minimising unnecessary hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables and distributed generation. 	All TA procurement arrangements contribute to the Government's climate change objectives by encouraging feasible alternatives to transmission, such as local/distributed generation and demand-side initiatives, and by provision of access to regulated procurement where such arrangements bring overall benefits to the industry.

Appendix 1: Grid Investment Process Overview



Appendix 2: Operational Constraints for the CP Options

292. In developing this paper, initial discussions centred on how a central procurement mechanism (as compared to relying on market response) could be defined to meet the requirements for TAs as outlined in the Rules.
293. This section outlines some of the underlying analysis undertaken to define the central procurement options. The Commission has included these details as an appendix in order to assist readers to understand how the definitions of the central procurement options (as included in the core of the paper) were reached.
294. The proposed objectives of a procurement regime are outlined in section 3 of this paper. The primary objective of this appendix is to determine operational requirements for centrally procured TAs that would minimise the differential impact TAs have on the market. In other words, determining operational requirements on TAs that would mimic the effects grid investment would have on the market.

A2.1 Offers in the Energy Market

A2.1.1 Introduction

295. Grid assets are provided to the System Operator at zero prices, and nodal pricing is used to ration access to the grid on a half-hourly basis. Large price separation often occurs when grid constraints become binding. Grid expansion would relieve those constraints, and reduce nodal prices in the congested region.
296. It is convenient to categorise trading periods according to whether TA services are required ("TA periods") or not required ("energy periods").

A2.1.2 The issue

297. In procuring generation TAs to defer or avoid grid expansion, the issue arises as to whether they should be required to offer their plant into the market at zero prices, as is the case for grid assets.
298. More broadly, the Commission is concerned that generators may have the ability to exercise temporary market power when grid constraints become binding. Relying on generation TAs to defer or avoid grid expansion, without imposing some limit on their offer prices, may allow generation TAs to exercise market power that would not have been possible if grid expansion had occurred. In this situation the Commission would be deliberately creating a situation in which a generation TA could exercise market power, or perhaps continue to exercise existing market power.

A2.1.3 The options

299. Three main options were identified:
- a. *Zero-price offers.* Under this option generation TAs would be required to offer energy to the market at zero prices during TA periods. Since generators receive whatever spot price prevails at their injection nodes, generation TAs would receive revenue reflective of nodal prices for provision of TA services. Generation TAs would be free to choose any offer price during other trading periods;
 - b. *Marginal-cost offers.* This is the same as the first option, except that offer prices would be set at marginal cost rather than at zero during TA periods; and

- c. *Unconstrained offers.* Under this approach generation TAs would not be constrained in the prices at which they offer energy to the market during TA periods or any other periods.

A2.1.4 Zero-price offers

- 300. The rationale for this option is that, in nominal terms at least, offers by generation TAs would be consistent with the zero-price offers made by grid owners. This ensures the provision of TA services has the same effects on nodal prices as would be achieved with grid expansion.
- 301. Under this option, generation TAs would receive compensation for TA services at the rates or fixed prices specified in their TA contracts. They would also receive spot market prices for energy supplied. It may appear as if this approach pays generation TAs twice for the same energy, but this is not the case. In bidding to be a TA, generators will have taken into account their ability to earn market revenue, and reduced their bid price accordingly.⁷⁵
- 302. The alternative is to pay generation TAs entirely from regulated funds for energy supplied during TA periods. This approach would involve channelling very large sums of money through the System Operator, which raises significant accountability issues and is not necessary. The Commission favours the market revenue approach, provided generation TAs cannot exercise market power as a result of their position as a TA.

A2.1.5 Marginal-cost offers

- 303. The rationale for setting offer prices at marginal cost is that it protects TAs from receiving market prices below their marginal cost of supply. Without this protection TA providers may become unwilling to supply TA services on demand (i.e. during TA periods).
- 304. Also, in real terms, the marginal cost approach mimics the zero-price offers made by grid owners. In effect, the marginal cost of supply is zero for grid owners (apart from losses, which are reflected in nodal prices), whereas it is positive for TAs. With offer prices capped at marginal energy costs, generation TAs receive revenue to cover their energy costs, and are, in effect, receiving zero prices for their provision of TA services. This approach will not always achieve the same nodal price outcomes as grid expansion.
- 305. A practical method for estimating the marginal cost of supply for each generation TA, and adjusting those estimates as circumstances change, is required under this approach.⁷⁶ This could be achieved by TA generators bidding their SRMC in the procurement tender, which would be used in evaluation in the GIT.

A2.1.6 Unconstrained offers

- 306. The rationale for not constraining offer prices is that it mimics the nodal pricing process that would occur if TAs were not procured. The rationale for procuring TAs is based on the view that TAs would fail to be built even if they yielded larger net market benefits than grid investment.⁷⁷ If the GIT and procurement address these failures effectively, there is no reason to constrain the offer

⁷⁵ In practice, generation TAs are likely to do this by estimating the additional cost of locating in congested areas, and deducting the additional market revenue they expect to earn from locating in regions with higher nodal prices. Accurately estimating additional revenue is likely to be very difficult, and will most likely be heavily "discounted" in bid prices.

⁷⁶ Determining the marginal cost of supply is relatively simple for thermal generation, but more complex for hydro generators. For thermal plant this cost would be defined in the TA contract.

⁷⁷ See the discussion on market problems, in section 4 of this paper.

prices of generation TAs, even though at times nodal prices may reach very high levels.

307. For example, suppose nodal pricing and the GIT did provide effective investment incentives for generation TAs. In this case, generators would provide additional capacity to congested regions when that was economic to do so, and would be free to set their offer prices as they wished. If they set their offer prices consistently too high, other parties would have incentives to enter the market over time to restore competitive price levels. The unconstrained option leaves generation TAs to do the same.
308. The unconstrained option amounts to a commitment only to build the TA generating plant (i.e. it overcomes the commitment problem). As no constraints on offer price are specified, neither are there any constraints on the offer quantity.⁷⁸ This option relies on the economic incentive, provided by nodal pricing, for the generator to offer its plant into the market at times of transmission constraint. The benefit the generator receives from the TA contract is increased certainty that the Commission will not change its mind on transmission investment decisions and leave it with a stranded investment. The benefit the Commission receives is certainty that the TA provider will proceed with its proposal.

A2.1.7 Comparison of zero-price and marginal-cost options

309. A key difference between these options is that the marginal-cost option ensures TAs receive at least their marginal cost of supply if they are the marginal source of generation. This protects TAs against being required to offer energy to the market at prices below their marginal cost, and should make generation TAs more willing to accept contracts that allow the System Operator to request services upon demand.
310. Both options allow generators to receive market prices for their energy. The difference between the two options is in regard to their offer prices, and therefore in the relative efficiency of dispatch. The zero-price option ensures generation TAs are dispatched when offered to the market,⁷⁹ whereas under the marginal-cost option, generation TAs would not be dispatched if total energy needs can be met from lower-priced generators.
311. This distinction matters only when mistakes are made regarding demand for TA services. For example, suppose peak demand is forecast to exceed transmission capacity, and a generation TA is requested to offer energy to the market. Consider two cases:
- a. *Case 1.* Suppose the forecast is accurate. The generation TA is needed to meet peak demand, and therefore would be dispatched regardless of whether it offered a zero price or a price based on marginal cost estimates; and
 - b. *Case 2.* Suppose the forecast is inaccurate, to the extent that the generation TA is not needed to meet peak demand. Nevertheless, the TA has been offered to the System Operator, and so is dispatched under the zero-price option regardless of whether it is the most efficient source of energy. Under the marginal-cost option the generation TA would not be dispatched if its price exceeded all other generator offers, and this would be a more efficient outcome than achieved under the zero-price option.

⁷⁸ Generators could potentially offer up to the VOLL price thus economically withholding their capacity from the market. They would, however, receive no obvious benefit from doing so.

⁷⁹ Other than in circumstances where must run auctions are used to prioritise dispatch.

312. In practice, it is unlikely there will be many trading periods where generation TAs, offered to the market at their estimated marginal cost, will be more expensive than other generators free to offer whatever price they wish. Moreover, it is not clear there will be many trading periods where forecasts are so inaccurate that a generation TA is required to offer energy when it is not needed.

A2.1.8 Comparison with the unconstrained option

313. The primary concern with the unconstrained option is the prospect that procured generation TAs may exercise market power during periods when peak demand exceeds transmission capacity. In practice, excess profits from market power are likely to be 'bid away' in the prices generators bid to be selected as a TA.
314. In practice, both the zero-price and marginal-cost options may not have any effect on the exercise of market power, at least in the short run (e.g. the next 10 years). For example, a generator owning both TA plants and ordinary generation plants could exercise market power by offering its ordinary plant to the market at very high prices. It does not matter which plant it uses to exercise market power since all dispatched energy is paid essentially the same price.⁸⁰
315. In the long run both options may constrain market power. For example, if most generation plants in "constrained regions" were also TA plants, then generators would have far less scope to substitute plants with uncapped offer prices for plants where offer prices are capped. In this case though, the normal arguments against price caps apply, which is that they discourage generator entry to the market if the price caps are set too low.
316. In practice, the long-run outcome just discussed seems unlikely, as grid capacity expansion is likely to be approved in the long run. The primary concern with the unconstrained option, therefore, is the perception it creates that a procured generator TA plant may use that plant to exercise market power.
317. One way of managing this perception risk would be for the Commission to over-contract for TAs, i.e. to contract for more TAs than are required to relieve the transmission constraint. This would effectively limit any market power of the contracted generators, by introducing competition on the margin. However, this option is likely to be expensive, as all TAs would build their expectations of market price into their TA tender bids. In practice this option becomes very similar to the marginal-cost option.

A2.1.9 Proposed approach to offers for CP options

318. The Commission decided to adopt the unconstrained approach to pricing as part of the definition of the minimal CP option. This allows generation TAs to offer energy to the market during TA periods at any prices allowed under the market rules (i.e. not constrained by TA status).
319. The Commission believes the unconstrained option is likely to achieve more efficient dispatch than the other two options. Like the marginal-cost option, the unconstrained option ensures that TAs are not exposed to the risk of receiving market prices below marginal cost for the provision of TA services. However, it avoids the downfall of the marginal-cost option in terms of the level of supervision this would place on the market.

⁸⁰ Prices will not be equal due to losses. Also, note that the presence of the generation TA means that grid constraints don't bind, and so all dispatched energy, not just energy dispatched in the region, receive essentially the same price. The paper sometimes uses "constrained regions" in quote marks to denote regions where peak demand exceeds transmission capacity.

320. By way of comparison, the Commission decided to adopt a constrained approach to pricing as part of the definition of the universal CP approach.

Q17: Do submitters agree that, if procured, generation TAs should be unconstrained in terms of offer prices for energy (as in the minimal CP option definition)? If you disagree what alternative would you propose and on what basis?

A2.2 Bids in the Energy Market

321. Currently consumers do not participate directly in the energy market as dispatchable demand, so currently there is no issue about constraining their bid prices.
322. As with generators, load TAs are both consuming energy and providing TA services during TA periods. To preserve neutrality with grid augmentation, load TAs should pay market prices for their energy off-takes, and receive compensation for TA services at rates specified in their TA contracts. In bidding to be a TA, new entrant loads will have taken into account their ability to pay lower market prices at non-congested nodes, and reduced their bid prices accordingly.

A2.3 Availability and Unplanned Outages

A2.3.1 Introduction

323. The reliability of TA plants will be specified by TA proponents, and verified by parties conducting the GIT. Proposals offering low reliability levels will need to have commensurately lower costs if they are to produce superior net market benefits in the GIT.
324. Once the plant is installed and operational, there will be trading periods when the plant is not available for unplanned reasons. This could cause power outages if other TAs are not available or are already fully utilised, but such events would be rare if TAs are contracted to provide high reliability levels, or if capacity reserves are used to provide cover for unplanned TA outages.⁸¹ This section proposes that TAs be required to meet contract availability guarantees and face financial sanctions if these were not achieved.

A2.3.2 The issue

325. It is essential TAs are made available to the System Operator at close to their rated reliability levels, or at least that aggregate performance in a region meets aggregate reliability commitments. As there may be many different types of TAs, offering widely different reliability levels, the issue arises about how best to ensure TAs meet their performance commitments, individually and in aggregate.

A2.3.3 The options

326. There would appear to be two main options:
- a. *Cost-recovery for under-performance.* Under this option TAs would be levied charges for under-performance, at rates specified in contracts; or
 - b. *Symmetrical financial incentives.* Under this option TAs would be provided financial incentives that reward over-performance and recover costs for under-performance, at rates specified in contracts.

⁸¹ Zero risk of power outages requires setting the system reliability standard at 100%, which is generally considered to be uneconomic.

A2.3.4 Discussion of the options

327. Implementation of the cost-recovery option would require the Commission to calculate the cost of under-performance, and set charge rates to recover those costs. Proposed charge rates would be published prior to parties bidding in TA tenders, so that bidders would have the ability to specify optimal reliability/cost trade-offs in their proposals.
328. Adopting symmetrical financial incentives encompasses the cost-recovery option, and so it would adopt the same methodology for determining charges and rewards (rewards being determined by estimating the benefits of over-performance relative to rated reliability levels).

A2.3.5 Approach to availability for CP options

329. The definition of the CP options includes symmetrical financial incentives, as over-performance by some TAs could provide a useful counter balance to under-performance by others.

Q18: Do submitters agree that symmetrical financial incentives that reward over-performance and recover costs for under-performance, are appropriate for the CP options? If not, what alternative arrangement would you propose to deal with availability and unplanned outages, and why?

A2.4 Notice for Provision of TA Services

A2.4.1 The nature of TA services

330. In general, in electricity markets, grid owners provide their assets to system operators as a standing offer, and the offer is generally only altered when the assets need maintenance and repairs. This means that transmission services are separated from energy services: the transmission service is available regardless of how much energy is conveyed on the grid, and regardless of who injects or takes-off energy.
331. In contrast, many TAs produce joint outputs. For example, generation TAs supply TA services and energy, which are not separable because energy has to be injected to provide the TA service. Similarly, TA services provided by consumers through demand-side mechanisms are not separable from energy consumption because reduced consumption is necessary to provide the TA service.

A2.4.2 Supply of TA services

332. Clearly it is not cost effective for some TAs to provide their services continuously, as grid owners do. For example, it may not be cost effective for generation TAs to continuously inject energy into the grid, if doing so displaces cheaper sources of energy. Likewise, it is not feasible for demand-side management TAs to continuously reduce their load. These requirements would be very costly, and would fail the GIT.
333. Having said that, some types of TAs provide TA services continuously. For example, TA services provided via energy efficiency measures.

A2.4.3 Incentives to supply TA services

334. Although generation TAs may not provide TA services continuously, they have strong commercial incentives to offer energy to the market when the grid would otherwise be constrained, as that is when they are likely to receive the highest prices for their energy. There may be issues about market power and price levels (discussed previously), but generators would nevertheless offer all available capacity to avoid outages.

335. Similar incentives would also apply for load TAs, provided they are paid on the basis of their volume reduction in consumption.

A2.4.4 Intermittent demand for TA services

336. TA services are needed to cover peak load periods when grid capacity is insufficient to meet demand for transmission, and to cover for (planned and unplanned) line outages. In general, grid capacity requirements are highly stochastic and dependent on the actions of other parties using the grid.
337. For example, TA providers in the Auckland region would be needed whenever transmission capacity limits, driven by voltage stability requirements, are reached. Transmission capacity limits in this case are a complex function of:⁸²
- a. Demand, in both real and reactive power terms;
 - b. The availability of transmission elements such as lines, interconnector transformers, and capacitor banks; and
 - c. Generation injection, in both real and reactive power terms, including the number of units at Huntly, Otahuhu, and Southdown.

A2.4.5 The issue

338. The stochastic and complex nature of demand for transmission services makes it difficult to accurately specify in advance when TA services are needed. This raises the issue of how much notice should be given to TAs to provide TA services to the market.⁸³

A2.4.6 The options

339. Three options were identified for notifying the requirement for provision of TA services. The requirement for TA services could be:
- a. *Notified 'as required' (option A)*. This approach would require TAs to offer their plant to the market at very short notice (subject to the normal scheduling process and offer rules), whenever requested by an authorised party. This is similar to arrangements in place for the Whirinaki reserve generation plant, but may not be feasible for some forms of generation technology;⁸⁴
 - b. *Specified in the contract but varied at cost (option B)*. Under this approach the times and dates for the provision of TA services are specified in the TA contract, based on forecasts of transmission capacity requirements for the life of the TA contract. If the TA is needed outside contracted times and dates, the authorised party can instruct the TA provider to provide the service and pay penalties to the TA provider at levels sufficient to compensate them for additional operating costs and risks; or
 - c. *Notified [x] days ahead but varied at cost (option C)*. Under this approach the times and dates for the provision of TA services are notified to the TA provider [x] days ahead of the requirement for the

⁸² These requirements were obtained from a Request for Information paper released by Transpower in September 2004, *Alternatives to transmission investment for meeting future electricity supply requirements for Auckland and North Isthmus*.

⁸³ Note that a request to provide TA services is fulfilled by a TA provider offering their plant to the market. Once offered to the market, the plant is available to be dispatched when needed to meet grid capacity requirements.

⁸⁴ Whether this option is feasible for all technologies would depend on how closely the current scheduling process is followed. Under the current scheduling process, TA providers would receive between 12 and 36 hours notice, which is likely to be adequate time for most technologies.

service, and would be based on forecasts of transmission capacity requirements for [x] days ahead. If the TA is needed outside the notified times and dates, the authorised party can instruct the TA provider to provide the service, and pay penalties to the TA provider at levels sufficient to compensate them for additional operating costs and risks.

A2.4.7 Discussion of the options

340. All options provide the System Operator with authority to request or instruct TAs to operate when required. The key differences are in regard to the period of notice for TA service requirements and the incentives on the System Operator to forecast TA service needs.
341. Option A allows the System Operator to request TA services at very short notice and does not provide incentives for the System Operator to minimise the use of the resource. This is consistent with the Commission's proposal to not constrain offer prices of generation TAs, as it ensures that TA providers are not 'left out of pocket' by such requests.
342. Options B and C are relevant where TA providers value advanced notice of Transpower's service needs. For example, if generation TAs can exercise market power during trading periods outside of TA periods, then they may value some discipline on the System Operator to require TA services only when it is required to address transmission capacity shortages.
343. Option B provides the longest notice period to TAs about the System Operator's likely service requirements, as notice is specified in the TA contract. This approach provides TAs with the greatest certainty about their likely service obligations, but carries the greatest risk (to the System Operator) that specified requirements fail to match the needs of the grid. Implementing this approach would encourage the System Operator to invest in appropriate forecasting systems.
344. Option C provides a compromise between options A and B, as the notice period lies in between the notice periods under those options. Relative to option A, this approach provides TAs with less certainty about their likely service obligations at the time that they are negotiating their TA contracts. On the other hand, it may be a more practical solution than option B if it is futile to attempt to improve long-range forecasts or if it is not costly for TAs to operate as required by the System Operator.
345. A key difficulty with options B and C is that it may be complex to determine penalty rates that provide balanced incentives. For example, penalty rates should be sufficiently high to compensate generation TAs for forgone commercial opportunities, but determining the value of those opportunities is rather tricky if they possess market power.

A2.4.8 Approach to notification of TA periods for the CP options

346. Option A is probably the best approach under both of the CP options. It is consistent with the minimal CP definition, under which energy offers would not be constrained for generation TAs during TA periods. Moreover, it would not make much difference if TAs were necessary most weekdays and weekends to cover planned maintenance on transmission and TAs.
347. Option C adds flexibility to option B, but the advantage of option B is that TA service requirements are based on firm contractual arrangements, which have to be agreed prior to final agreement to provide TA services.

Q19: Do submitters agree that under the CP options, the System Operator should be able to provide notice as required for operation of TAs? If not, what alternative arrangement to deal with notice would you propose, and why?

A2.5 Requirements for Planned Outages

A2.5.1 Generation TAs

348. Generation TAs will want to be available for operation when nodal prices are expected to be high, which is also when they are needed for grid security reasons. In theory, there does not appear to be any need to require generation TAs to obtain the agreement of the System Operator (in its procurement role) to schedule planned maintenance.
349. Nevertheless, the consequences of a lack of co-ordination of maintenance schedules could be very high, and could undermine market arrangements. As the TA is providing contracted services, it would be prudent to specify in the contract an obligation on the TA to obtain the System Operator's approval for planned maintenance.⁸⁵

A2.5.2 Load and network TAs

350. As with generation TAs, load TAs will want to be available for operation when nodal prices are expected to be high. Again, it would seem reasonable to specify in the TA contract an obligation on the TA provider to plan maintenance for periods when system peak is not likely to occur or other assets are out of service. The same applies to network TAs.

Q20: Do submitters agree that the definitions of the CP options should include a requirement that TAs seek the System Operator's approval for any planned outages? If not, what alternative arrangement to deal with planned outages would you propose, and why?

A2.6 Interaction with Reserve Energy

A2.6.1 Introduction

351. The Commission contracts for reserve energy from the Whirinaki plant, which is owned by the Crown. It intends to hold tenders for additional reserve energy when the 'needs analysis' shows further supply is required to meet the Government's security of supply standard.
352. Generation TAs may wish to supply reserve energy to the wholesale market, under contract to the Commission. This section discusses how TA generation should interact with reserve generation and whether any constraints on that interaction are necessary.

A2.6.2 Physical interactions

353. In physical terms, the provision of TA generation does not appear to conflict with the provision of reserve generation. For example, suppose a generation TA is contracted to provide reserve energy to the market. Consider two situations:
- a. Suppose the generation TA is dispatched to meet transmission capacity requirements and then a regional security of supply situation arises. The generation TA is already supplying energy to the market so it is already assisting with the regional security of supply problem; and
 - b. Suppose the generation TA is dispatched to meet regional security of supply requirements and then a transmission capacity situation arises. The generation TA is already supplying energy to the grid, so it is already assisting with the transmission capacity problem.

⁸⁵ Force majeure clauses may be required to cover forced outages.

354. This illustration shows that generation TAs can fulfil transmission and reserve energy tasks simultaneously. For grid security this does require that the Commission and the System Operator know which plants are contracted to fulfil both roles, and know when they are dispatched.

A2.6.3 Financial interactions

355. The current policy is for reserve energy to be offered to the market at the higher of \$200 per MWh or the variable cost of supply. Also, reserve generators receive cost-plus funding from the Commission and it is the Commission that receives market prices at relevant injection nodes.
356. In contrast, the proposal here is that, under the CP options, TA generators should not be constrained with regard to the prices at which they offer energy to the market during TA periods, and they will be paid marginal prices and receive their revenue directly from the market. This suggests the primary areas of conflict between the two roles relate to pricing and financial arrangements.

A2.6.4 Pricing

357. The minimum \$200/MWh offer price for reserve energy is intended to reflect a reasonable estimate of the long-run marginal costs of operating a diesel-fired station to meet relatively infrequent hydrological events. The \$200 offer price is also intended to provide comfort to generators that reserve energy will not be used to crowd out investment in ordinary generation.
358. The pricing policies for reserve energy reflect vagaries with determining whether energy supply shortages are pending. For example, energy shortages become apparent over a period of several weeks, and even then there is usually a wide range of views about the potential severity of the pending supply shortage. In these circumstances, the pricing policy is strongly influenced by the need to minimise risks of crowding out investment in ordinary generation.
359. In contrast, transmission capacity shortages arise from unpredictable demand peaks, and develop very quickly. In practice, there may be very little time to assess whether TA services are required.

A2.6.5 Financial arrangements (double dipping)

360. The potential for generators to fulfil both transmission and reserve energy roles raises concerns about double dipping – plants being paid twice for the same energy. In practice, double dipping should not arise provided competitive tenders are conducted for both roles.
361. For example, suppose a generator has competed in a tender and gained approval to provide TA services, for which it receives regulated income and earns market revenue for energy delivered during TA periods. If the Commission subsequently conducts a competitive tender for reserve energy, the TA generator has strong incentives to reflect in its reserve energy bid the portion of its expected TA revenue stream that overlaps with provision of reserve energy.
362. The same logic applies for a reserve generator that bids in a tender to provide TA services. Provided the TA tender is competitive, the reserve generator has strong incentives to reflect in its TA bid the portion of its expected revenue stream from reserve generation that overlaps with the provision of energy as a TA.

Q21: Do submitters agree with the assessment that, under the CP options, no restrictions need to be placed on TA provider's ability to participate in the reserve energy arrangements? If not, on what basis do you disagree and what alternative arrangement would you propose?

A2.7 Participation in Other Markets

A2.7.1 Introduction

363. In addition to the energy market, generators and loads participate in other markets. For example, both can participate in the instantaneous reserve (IR) markets, and both will be able to provide capacity reserves (CR) if this arrangement is established under the rules. Generators also provide other ancillary services, such as voltage support, black start, and so on.
364. As with the energy market, the key issue is to avoid effects that would not occur if grid augmentation were chosen instead of TAs.

A2.7.2 The IR market

365. Generation and load provide reserves to the IR market to cover for single credible generation contingencies, such as unexpected generation outages.
366. TA generation is just ordinary generation under contract to offer energy to the market when instructed to do so by the System Operator. Ordinary generators offer the same capacity to the energy and IR markets, so in principle the same approach can be adopted for TA generation.
367. In practice, TA generation offered to the energy market is likely to be dispatched when offered, to address transmission capacity shortages, and therefore will generally not be available for dispatch in the IR market. Nevertheless, there does not seem to be any reason to prevent TAs from offering reserves in the IR market, as the SPD model co-optimises the two markets.
368. A similar approach applies to load TAs. Consumers do not bid dispatchable demand into the energy market, but nevertheless offer interruptible load to the IR market. If a load TA offers into the IR market, and is activated, then it is in effect already providing TA services. If a transmission shortage developed when a load TA was already activated via the IR market, then grid security is no worse-off provided the System Operator knows about the activation.

A2.7.3 The CR market

369. Capacity reserves are blocks of load or generation contracted to adjust automatically after a contingent event to maintain acceptable flows on transmission circuits. They perform a role for transmission contingencies analogous to the role IR plays for generation contingencies.
370. Capacity reserves could be considered a type of TA. An ordinary TA alters energy supplied or demanded on a pre-contingent basis (i.e. before a transmission contingency occurs), whereas capacity reserves provide automated post-contingent activation. The provision of automated activation allows the grid to be operated at higher line ratings, which reduces the frequency and duration of grid congestion because security constraints in SPD are revised accordingly.
371. Defining TAs to include capacity reserves would provide an avenue for providers of capacity reserves to acquire regulated certainty of income. The Commission is currently considering adopting proposed rules to allow CR arrangements, where capacity reserves would be offered to the System

Operator at zero prices on a half-hourly basis.⁸⁶ The proposed rules provide the basis for CR capacity to be offered to the energy and IR markets, and is not repeated here.

A2.7.4 The must run dispatch auction

372. The must run dispatch auction (MRDA) provides the basis for generators to compete for the right to be dispatched at zero prices. From a grid security perspective, there is no need to prohibit or restrict TA generation from participation in the MRDA, as TA generation is just ordinary generation under contract to the System Operator (in its procurement role).⁸⁷ It is extremely unlikely that TA generators would be required to operate for transmission limits at times of minimum load, as an MRDA is usually only required in an export constrained region. Also if the unrestrained offer price approach is adopted there are no constraints on TA generators offering into the MRDA. It is therefore concluded that there would be no need to restrict TA generators from participating in the MRDA.

A2.7.5 Other ancillary services

373. In some cases (such as the top of the South Island) the key issue for avoiding transmission investment is voltage support. In such cases TAs will already be providing voltage support as part of their TA contract.

Q22: Do submitters agree with the assessment that no restrictions need to be placed on TA provider's ability to participate in the IR, CR, and MRDA markets? If not, on what basis do you disagree and what alternative arrangement would you propose?

⁸⁶ See the Commission's consultation paper *Recommended Approach and Rule Changes for Capacity Reserves*, (released July 2004), available at www.electricitycommission.govt.nz.

⁸⁷ TA generation could be characterised as "must offer" generation.

Appendix 3: Tests for the Minimal CP Option

374. In order to minimise the potential distortion on market determination of generation and load the Commission is considering using some or all of the following tests when deciding which TAs to procure if the central procurement approach is adopted. These are:

- The Free Riding Test;
- The Commercial Test; and
- The Price Cap Test.

A3.1 Free Riding Test

375. The winners and losers from any transmission or TA investment will have incentives to seek central funding of their investments even when they would undertake them without funding. Therefore the System Operator will need a very clear and prescriptive test on whether a TA requires procurement or not. As free riding is a key barrier to market based TA investment, it is proposed that a free riding test be adopted as part of the regime for central procurement.

376. Free riding is where one party can benefit from another party's investment without having to contribute towards that investment. This causes under investment when it reduces the commercial returns to projects below the investor's hurdle return for investment.⁸⁸ Under-investment occurs even when commercial returns exceed required hurdle rates of return if free riding confers competitive advantages to competitors.

377. Free rider problems arise in regard to both nodal pricing and transmission charges. In regard to nodal pricing, the essence of the free rider problem is that small changes in demand cause large price changes during periods of grid congestion. This creates a free rider problem, because a few consumers investing in demand reduction equipment and processes, and forgoing profits from reducing their output, reduce electricity prices for everyone else. Hence, there will be situations where the commercial incentives for demand reduction fall short of the economically efficient incentive.⁸⁹

378. In regard to transmission charges, the free rider problem arises because charges are levied on parties in proportion to their off-take of electricity.⁹⁰ In theory these free rider problems would not arise if transmission charges were location-based, levied at rates equal to the LRMC of grid expansion, and levied on all direct and indirect grid users. In this case each party would receive the full value of avoided transmission costs when they reduced demand for transmission, but in practice there are significant practical computation and implementation problems with adopting such a charging regime.

⁸⁸ There are of course many situations where investments remain commercially viable even with free riding activity, in which case investors undertake them despite free riding problems.

⁸⁹ In most industries free rider effects are minimal because individual consumers are too small to affect prices. In these cases the savings consumers make from reducing consumption provide the economically efficient incentive for them to act, but this is not the case with electricity because of the binary nature of grid constraints, which causes the large price reactions to small changes in demand.

⁹⁰ In the case of HVDC charges free rider problems arise because transmission charges are levied in proportion to their injection of electricity.

A3.1.1 The free riding test for nodal pricing

379. In regard to nodal pricing, the free riding test comprises four elements:
- a. Determining whether the proposed TA satisfies technical requirements for it to potentially suffer free riding problems with nodal pricing;
 - b. Determining the aggregate magnitude of TAs necessary to substantially affect nodal prices at proposed GXPs;
 - c. Assessing whether the TA on offer to the Commission is large enough to substantially affect nodal prices at proposed GXPs; and
 - d. Assessing the incentives for beneficiaries of the TA to resist contributing to the cost of the TA.
380. The first element of the free riding test is to determine whether the TA can offer prices into the market during periods of grid congestion. TAs that offer prices into the market can avoid the free rider problem by offering prices sufficient to earn a commercial return on their investment (provided their prices are not so high as to attract competitor entry). If they cannot earn sufficient returns due to implicit price caps, for example, then the problem is not a free rider problem and should be addressed through other mechanisms (discussed below). This is the case for large generator/retailer TAs, for example. It may also be the case for small generators, as they may be able to develop agency arrangements with larger generator/retailers to economise on the costs of complying with offering rules. TAs that do not submit prices into the market or whose prices are not used for determining real-time prices - for example demand-side TAs and network TAs - potentially suffer free rider problems.
381. The second element of the free riding test is to determine the magnitude of demand reduction or voltage or capacitor expansion (e.g. by distribution companies) necessary to substantially affect nodal prices. This requires analysis using the SPD model to estimate these effects for proposed GXPs over the time periods relevant to the TA proposal. To conduct this analysis it will be necessary to define "substantially affect nodal prices".
382. The third element of the free riding test is to determine whether TA parties that potentially suffer free rider problems actually suffer free rider problems. This involves assessing whether the TA party offers volumes large enough to affect nodal prices. For example, an individual household is unlikely to suffer free rider problems because changes in their demand are too small to influence nodal prices. Similarly, if there was a single large consumer using all electricity downstream of a congested line then there is also no free rider problem because the consumer receives the full benefits of the price reduction on their own consumption.
383. The third element of the free rider problem therefore requires an economic assessment of whether a proposed TA is large enough to influence nodal prices but not large enough to capture most of the benefits of price reductions. This assessment would need to take into account strategic interaction situations, such as where there are x number of TAs (e.g. four) that on their own have little influence over nodal prices but any $x-1$ of them can significantly influence nodal prices. In this case, they each have incentives to wait for the other parties to make the investment.
384. The fourth element of the test requires the identification of whether beneficiaries of the TA have strong incentives to conclude side-contracts with the TA to ensure it eventuates and brings them lower nodal prices. For example, where there are only two large beneficiaries of the TA, both face strong incentives to fund the TA because they both know the investment will

not otherwise occur. This contrasts with situations where there is one or two large beneficiaries and lots of small beneficiaries, as in this case the small beneficiaries face incentives to resist contributing to the funding of the TA in the hope the TA will go ahead anyway.

A3.1.2 The free riding test for transmission charging

385. The free riding test for transmission charging comprises three elements:
- a. Assessing whether the TA will substantially reduce transmission charges paid by parties likely to benefit from the proposed TA investment;
 - b. Assessing the proportion of those savings received by the TA provider; and
 - c. Assessing the incentives for TA beneficiaries to resist contributing to the cost of the TA investment.
386. The first element of this test is to determine whether a proposed TA is likely to substantially reduce overall transmission charges. TAs that provide small megawatt effects, for example, will have little effect on transmission charges, making it not worthwhile for the TA provider and TA beneficiaries to negotiate funding contracts. In this case contracting costs exceed the benefits of coordinated action, and free riding is not a problem.
387. For TAs likely to substantially reduce transmission charges, the second element of the test is to determine whether the TA is likely to receive a high proportion of the savings. For example, TAs on some spur lines may receive most of the savings in transmission charges and so free riding is not likely to greatly affect their investment decisions.
388. The third element of the test is the same as for the free riding test for nodal pricing.

A3.2 The Commercial Test

389. The commercial test takes the analysis one step further than the free riding test. The free riding test identifies whether a TA provider suffers significant free rider problems, which implies that some TA investment does not occur when it is economically efficient to do so, but it does not assess whether a substantial portion of the TA investment would occur anyway. For example, many parties may find it commercially viable to invest in TAs even if they capture only 25% of the benefits provided to the market. The commercial test involves assessing the commercial returns to TA proposals to determine whether they would occur anyway even with free rider problems.

A3.3 The Price Cap Test

390. Peaking plant, such as Open Cycle Gas Turbines (OCGTs) can provide a TA service similar to other generators. However, peaking plant is designed to recover its capital cost in very short duration periods, i.e. it may only be required for a few hours per year. Therefore, its energy price to cover the capital cost has to be very high in these few short periods per year.
391. Investors in peaking plant may have concerns that the prices necessary to cover their capital costs may be politically unacceptable or that other forms of regulatory intervention (such as the Whirinaki plant) may distort prices and limit their ability to recover full capital costs within their required payback timeframe.
392. To cover this risk, peaking plant investors might delay investment beyond the socially optimal time to increase the frequency and duration for which they are dispatched.

393. The market solution would be for the beneficiaries of peaking plant (the load customers in the region) to contract with the peaking plant via an option contract, structured as a contract-for-differences (CFD) against nodal prices at the relevant GXP. This provides the peaking plant owner with certainty of income and provides customers with certainty about prices.
394. The problem with the option contract approach, however, is that it brings low prices to all consumers, not just to those holding option contracts. This creates a free rider problem that would not exist if owners of peaking plants were confident that implicit price caps did not exist so that they could recover all of their costs from the spot market. In this case the free riding test for nodal pricing should be applied.

Q23: Do submitters agree that all of these tests are required, and if not why not? Do they need to be simplified, and if so, how would you do that?

Appendix 4: Review of the RCC Option

A4.1 Summary

395. Contact Energy has put forward a proposal for a decentralised procurement regime referred to as regional capacity contracts (RCC). This paper presents a summary of the RCC proposal, assesses its merits and identifies some possible implementation issues.
396. In summary, the RCC proposal has the following advantages relative to central procurement:
- It facilitates innovation in delivery of TAs, which is likely to reduce the cost of providing TAs over the longer term;
 - It involves minimal risk of increased regulatory intervention (and/or market distortion), as it allows a "market" for regional capacity to develop; and
 - It provides a simple verification mechanism, as it is financial rather than physically based.
397. The disadvantages of the RCC proposal relative to central procurement are:
- It is unlikely to achieve the same degree of certainty that TAs would emerge;
 - There are significant implementation issues that have not been considered in detail (e.g. the mechanism for allocation of regional requirements, how a penalty regime will work in practice, etc.);
 - The proposed prudential regime may impose barriers to entry for new entrant retailers⁹¹, although the magnitude of this problem may not be major; and
 - To be sustainable, it may require location-based pricing for new transmission investments.

A4.2 Introduction

398. This paper considers whether procurement of TAs is preferable to leaving investment decisions to the market, and whether central procurement is preferable to decentralised procurement. Some parties have expressed concern that centrally procuring TAs could result in dynamic efficiency losses, by causing increasing regulatory intervention in generation investment decision-making.
399. Contact Energy has proposed a decentralised procurement mechanism as an alternative to central procurement. The intent of such a mechanism is to provide the same benefits as a central procurement arrangement without the risk of increasing regulatory intervention.
400. This paper examines the proposed RCC mechanism, compares it with the alternative of central procurement, and considers how the central procurement option could be improved by adopting some of the key features of, or ideas underlying, the RCC proposal.

⁹¹ The Contact Energy proposal is based on DSEs being retailers or directly connected consumers. The Commission does not necessarily share this view.

A4.3 Description of the Proposal

A4.3.1 Objective of the Mechanism

401. The premise for developing a decentralised mechanism for procurement of TAs is that decentralised, market-based, investment decision processes will achieve better (more efficient) outcomes than centralised investment decision processes. This is because the parties with the best information and incentives to invest are those that are responsible for funding and implementing the investment.
402. Decentralised mechanisms are desirable because they have a lower risk of increasing regulatory involvement in the investment decision process, which could cause significant dynamic efficiency losses over time.
403. The RCC mechanism proposed by Contact Energy is one such decentralised option. This model was developed, not as a mechanism ready for immediate implementation, but to show how a mechanism might work, and what benefits it might have over central procurement. If it can be shown that there are benefits to further consideration of decentralised mechanisms, then other options, including variations on the proposed design, will be investigated.

A4.3.2 Key Features of RCC

404. The key features of the proposed RCC mechanism are:
- Self-forecasting of DSEs' capacity requirement at times of regional system peak;
 - DSEs responsible for meeting capacity requirement;
 - Assignment of existing transmission capacity among DSEs;
 - Flexibility in meeting requirements;
 - Verification, and penalties for non-compliance; and
 - Prudential security requirements.

Self forecasting of capacity requirement

405. DSEs determine their own forward estimates of their regional demand at times of regional system peak. This is determined 18 months ahead of real time. A penalty regime (explained later) provides an incentive for truthful, if conservative (over-forecasting capacity requirements) forecasting at this point.
406. It is likely that a decentralised mechanism will over-procure TAs, because the costs of under-procuring (penalties) are significantly greater in magnitude than the costs to over-procure.⁹² This represents the inherent asymmetric costs associated with over- or under-procurement of capacity.

DSEs responsible for meeting requirement

407. The DSEs have to periodically advise their RCC level and are responsible for meeting their forecast capacity requirement at all times between 18 months out, right up until real time. This effectively creates a "causer pays" regime for transmission capacity. They can do this through a combination of assigned transmission capacity, contracted TAs and self-provided TA services such as load shedding.

⁹² Equally, a central procurement arrangement is likely to over-procure TAs, as the System Operator faces strong political incentives to ensure that sufficient capacity is available.

Assignment of existing capacity

408. Part (or all) of each DSEs regional capacity requirement can be met by the existing transmission capacity. Under RCC, rights to existing transmission capacity (including new investments approved via the GIT process) are pro-rated to DSEs based on historical coincident peak regional demand, i.e. the extent to which they caused the need for the capacity. This is reassigned each year.

Flexibility in meeting requirement

409. If there is insufficient existing transmission capacity to supply the forecast demand in a region (taking into consideration local resources), then DSEs will be responsible for making up the difference. This can be met from a variety of sources, including local generation, energy management (including energy efficiency initiatives) or demand-side management, or through financial contracts with parties with surplus capacity.
410. A key feature of the RCC proposal is that it maximises the flexibility DSEs have in meeting the capacity requirement. This flexibility is intended to encourage innovation and efficiency in meeting the requirements.
411. DSEs also have flexibility in the timing of meeting the requirement. While initial forecasting and allocation of requirements is undertaken 18 months ahead of real-time, DSEs can trade capacity rights right up to real-time, in order to accommodate changes in their position. This reduces the impact of such requirements on retail competition, i.e. it allows DSEs to trade their capacity allocation rights to reflect changes in their retail customer base.

Verification and penalties for non-compliance

412. In order to encourage truthful self-forecasting of peak demand by DSEs, a verification and compliance regime is essential.
413. The verification is a two step process:
- a. First, the 18-month ahead self-forecast of the DSE's contribution to regional peak demand is verified. This forecast is affected by both the number of customers the DSE will have and its view of the likely worst case peak demand. The DSE is able to adjust this forecast (to account for customer churn etc.) up to some point just before real-time. In real-time each DSE's actual contribution to the regional peak is measured, based on actual numbers of customers and actual peak. If it is found to have under-forecasted, it would face some severe penalty based on VOLL. It is important to note that an under-forecast does not necessarily result in a loss of load situation as some parties might have over-forecasted (and hence over-contracted) and some under-forecasted; and
 - b. Second, should a loss of load incident occur, the party whose TA didn't perform, or who was under-contracted, will face VOLL penalties. This second stage penalty function avoids the need to verify that proposed TA arrangements would work in practice, as the proposing party has the right incentives to ensure performance.
414. The attraction of this verification mechanism is that it is relatively simple, being based on measurement of actual performance on the day rather than trying to anticipate in advance whether a particular asset will perform as promised. This reduces the ability to game the system, as well as assigning the costs of any shortfall in transmission capacity⁹³ to those causing the

⁹³ The use of the term "transmission capacity" in this context includes TA capacity.

shortfall. The latter point means that DSEs directly face the appropriate cost of security, and can, therefore, make cost-security trade-offs.

415. The proposed regime does not directly deal with the impact on other parties of one party's failure to secure sufficient capacity. For example, if a shortfall in capacity by one DSE led to a loss of load incident the DSE in default would be financially penalised but the affected customers might belong to other DSEs. The proposal does not address how these customers might be compensated. It is presumed that the financial nature of the penalty regime could be used as a basis for compensation between those causing the shortfall and those affected by the shortfall. It is, however, noted that such a compensation regime might be difficult to implement in practice, as it would be hard to determine how much different customer groups should be compensated.

Prudential arrangements

416. In order for the financial penalties to be enforceable, and to avoid incentives for economic default, i.e. avoid incentives for poor forecasting, a prudential security regime is proposed.
417. Each DSE would have to provide prudential security for some forecast of the likely maximum penalty they could face. Without such a prudential regime, DSEs would have incentives to under-forecast their peak demand. For example, a new entrant retailer⁹⁴ could under-forecast its capacity requirements, and by doing so reduce its costs, enabling it to gain customers and short-term profits. Then once its actual capacity requirement exceeds its contracted amount it could simply exit the market, leaving the remaining retailers to bear the risk of a capacity shortfall.
418. The advantage of a prudential security regime is that it will give the Commission a greater degree of regulatory certainty, and comfort that parties proposing TAs have the right incentives to ensure they emerge.

A4.4 Benefits of RCC

419. The key benefits of decentralised procurement mechanisms, including the proposed RCC mechanism are that they:
- Put incentives in place that should give the regulator enough certainty that sufficient capacity will be made available;
 - Reduce (relative to central procurement) the likelihood of regulatory intervention in generation and demand-side investment, which reduces the risk of increasing intervention in investment decisions;
 - Encourage innovation in meeting capacity requirements, potentially reducing cost of procurement compared with a central procurement approach;
 - Provide a transparent price for capacity; and
 - Devolve decisions on purchase of capacity to those bearing the consequences of inadequacy.

A4.4.1 Improves regulatory certainty

420. The combination of forecasting capacity requirements, applying financial penalties for not meeting the capacity requirement, and requiring prudential requirements to make the financial penalties enforceable, *should* give the Commission a reasonable degree of comfort that the necessary TAs will

⁹⁴ This example assumes that DSEs are retailers.

emerge if they have been identified by the GIT as being the best solution. The Commission should then have sufficient confidence to decline a transmission investment. However, achieving this confidence may take some time (5-10 years).

421. The proposed mechanism relies on longer-term market responses to a relatively short-term price signal (although a longer-term price signal than nodal pricing). It assumes that forecasting capacity requirements 18 months out will provide a sufficient capacity price signal for parties to make long-term investment decisions. For example, a party proposing to invest in a new generator in a transmission constrained region would be able to see from the long-term trend of the capacity price whether it is likely to be able to recover sufficient money from the capacity market to justify committing to an investment decision some years out.
422. The regulator may not share this confidence in market investment mechanisms. It may wish a higher degree of certainty through more direct control. For example, it may not feel confident that a forecasting process that only looks 18 months ahead provides enough certainty to delay a transmission investment that has lead time of, say, five years.

A4.4.2 Reduces the “slippery slope” risk of increased regulatory intervention

423. By decentralising the TA investment decision process, the RCC mechanism moderates concerns that regulatory involvement in TA procurement could lead down a “slippery slope” of increased regulatory intervention. The same would apply to other decentralised procurement regimes.

A4.4.3 Encourages innovation in how TAs are arranged

424. By decentralising TA investment decisions to those who bear the costs of TAs, the RCC proposal places strong incentives on the TA providers (DSEs) to be innovative in how they meet the capacity requirement. The same would apply to other decentralised procurement regimes.

A4.4.4 Provides a transparent price for capacity

425. By allowing transparent trading in capacity rights the RCC mechanism will allow a transparent price for transmission capacity to develop. It is likely that other decentralised TA procurement regimes could also be designed that provide this benefit.
426. The developers of the RCC mechanism state that it is not necessary to know the value of capacity a number of years ahead – what is important is knowing that capacity will continue to have a value into the future.⁹⁵ Knowing that capacity will have a value into the future not only appropriately values existing generation assets, but also provides incentives for further capacity providing investments to be made.

A4.4.5 Devolves decisions on purchase of security to those bearing the consequences

427. By putting the requirement to meet the capacity requirement on DSEs, who represent the beneficiaries of capacity, the RCC mechanism allows parties to make their own decisions on how much they are prepared to pay for capacity. It is likely that other decentralised TA procurement regimes could also be designed that provide this benefit.

⁹⁵ Similar to the spot market for electricity, where the price is not known ahead of time, but it is known that there will be a price for electricity.

A4.4.6 Possible precursor to location-based transmission pricing and FTRs

428. It is also worth noting that the proposed RCC mechanism is, in some ways, a substitute for locational transmission investment pricing. This is because the price of capacity is a centrally produced signal, faced by causers, about the need for new transmission (or TA) investment.
429. Also, the proposed RCC mechanism creates a property right over existing, and new, transmission capacity. It can thus be seen as a possible precursor to any FTR mechanism.

A4.5 Problems with RCC

430. While RCC appears to be a potential decentralised procurement option, a number of design and implementation issues have been identified during this review. The Commission recognises that the RCC proposal is still under development and, therefore, has not resolved all the potential issues or problems.
431. Some of the issues may prove significant, and further work will be required to resolve them if the RCC proposal, or something similar, is to be implemented. Some issues that have been identified are:
- The impact of prudential security requirements on retail competition;
 - Difficulty in determining capacity allocations and requirements;
 - Difficulty in verification at DSE level; and
 - Inconsistency with the current transmission pricing regime.
432. Another, less technical, issue is that the RCC proposal could be perceived as providing windfall gains to existing generation assets in constrained regions. If this was a significant concern then transition arrangements might need to be considered.

A4.5.1 Prudential requirements are a barrier to entry for retailers

433. The RCC proposal suggests that prudential security should be required from DSEs, based on the potential non-compliance penalties they could face. These requirements are likely to be severe and could be a barrier to new, smaller, retailers⁹⁶ entering the market.
434. For example, if we assume a penalty cost of VOLL of \$20,000/ MWh and a prudential requirement of 100% of peak load, then a new entrant retailer who gains a customer base of 10,000 domestic customers (with a peak demand of 10kW each) in its first year, would have to put up \$2 million in prudential security.⁹⁷ This problem reduces over time as the new retailer would be allocated a portion of existing transmission capacity in subsequent years and its capacity requirement, and prudential security, would consequentially reduce. It is noted that a DSE could reduce the prudential requirement by obtaining contract rights over new generation or, if they existed, FTRs.
435. The Commission needs to consider whether this would be a significant barrier to entry to new entrant retailers, whether retailers are the appropriate DSE party and whether other ways of addressing this issue could be devised.

⁹⁶ The Contact Energy proposal is that DSEs would be retailers or direct connected consumers. The Commission does not necessarily accept the view that DSEs could only be retailers or directly connected consumers.

⁹⁷ Calculation is 10,000 customers x 0.01 MW x \$20,000/MWh.

A4.5.2 Difficulty in determining capacity rights and requirements

436. The same difficulties faced in determining location-based transmission prices would be faced in determining how to allocate existing capacity rights to DSEs in a region. For example, where loop flows can exist, or transmission patterns change over time, it could be difficult to determine the boundaries of a transmission region.
437. This could create incentives to game the boundaries of a transmission region. For example, if a load was on the boundary between one transmission region with a high cost of capacity, and another with a low cost of capacity, it would face huge incentives to argue for a redrawing of the boundaries to exclude it from the high-cost region.

A4.5.3 Difficulty in verification at DSE level

438. The proposed RCC mechanism allocates the responsibility for capacity procurement to DSEs rather than distributors. One of the problems with allocating transmission or TA costs and responsibilities to retailers is that it is considerably more difficult to determine accurately their contribution to a regional peak (and, hence, capacity requirement) than is the case for a distributor.
439. Accurate figures for retailer contribution to a regional peak depend on accurate information on how many customers each retailer has and of what type. The Commission is not confident that the reconciliation process is sufficiently robust to accurately provide this information, particularly as current profiling methods do not take into account changes in load behaviour in response to price changes.
440. Allocating penalty costs based on reconciliation information also provides added incentives for retailers to game the reconciliation process.
441. As these problems could be avoided by defining DSEs to be lines companies, the Commission would appreciate receiving the views of interested parties on this matter.

A4.5.4 Relationship to transmission pricing regime

442. The proposed RCC mechanism allocates responsibility to procure new TA capacity on a locational basis. However, if DSEs fail to provide TAs then eventually the transmission investment would be approved. The cost for any new transmission investments would, under the current regime, be allocated on a postage stamp basis (for core grid investments). Therefore, DSEs may not face the full costs of the transmission investment. They would have incentives to not procure sufficient TAs and force a transmission investment.
443. This is likely to be a problem for any decentralised procurement regime with postage stamp cost allocation for new transmission investments.

<p><i>Q24: Do submitters agree significant reconciliation problems would arise with allocating capacity contracts based on metered load?</i></p>
--

Appendix 5: List of Consultation Questions

<i>Question 1</i>	Do submitters agree Tables 1 and 2 contain the correct evaluation criteria, and are they weighted appropriately? If not, what criteria and weightings would you use? Do submitters agree the scores in Table 2 accurately reflect the evaluation provided in Table 1 and section 5.2? If not, how would you score the options in Table 2 so that Table 1 is consistent with Table 1?
<i>Question 2</i>	Do submitters agree with the problem definition outlined above? Why, or why not? Do submitters consider the optimal amount of transmission investment and TA investment has emerged in the past? Why, or why not?
<i>Question 3</i>	Do submitters agree with the Commission's view that the System Operator could undertake the service provider role of central procurement agent? Why, or why not? Do you see any problems with such an approach?
<i>Question 4</i>	Do submitters agree that DP options are inconsistent with postage stamp pricing for new grid investments? If not, please explain.
<i>Question 5</i>	Do submitters believe any of the "other options" in section 3.9 should be developed further? Are there other options not covered in this paper that should be considered?
<i>Question 6</i>	In the event that a DP regime is selected for further development, should DSEs be retailers or distribution companies? Please explain your response.
<i>Question 7</i>	Do submitters agree with the assessment of the investment certainty and regulatory commitment issues? Why, or why not?
<i>Question 8</i>	Do submitters agree with the assessment of free rider problems in regard to transmission charges? Why, or why not?
<i>Question 9</i>	Do submitters agree with the assessment of free rider problems in regard to nodal pricing? Why, or why not?
<i>Question 10</i>	Do submitters agree with the assessment of the nodal pricing deficiency issues? Why, or why not?
<i>Question 11</i>	Do submitters agree with the general framework regarding 'slippery slope' risks outlined in section 4.6.1, and the discussion here? If not, what alternative framework should the Commission consider? Do submitters agree that 'slippery slope' risks depend greatly on the details of the TA procurement regime? Do submitters believe that these risks can be managed under the minimal CP and limited DP options? Why, or why not?
<i>Question 12</i>	Which option(s) do submitters prefer? Why? Do submitters agree with the assessment of the various options against the decision criteria? Why, or why not? Would your views change if location-based transmission charges were adopted, instead of the current proposal to adopt postage stamp charges?
<i>Question 13</i>	Do submitters agree that the Commission has identified the costs and benefits of procurement options that need to be included in its cost-benefit assessment? Why, or why not?
<i>Question 14</i>	Do submitters have any views about the likely value of avoided transmission investment, costs of procuring TAs, benefits or costs relating to quality differences between transmission and TAs, any costs relating to sub-optimal procurement, the option value of delayed transmission investment, and the impact on dynamic efficiency from procurement of TAs?
<i>Question 15</i>	Do submitters consider that decentralised procurement is likely to result in lower procurement costs but higher administration costs?
<i>Question 16</i>	Do interested parties agree with the assessment of the procurement

	options against the Commission's principal objective and the GPS outcomes? Why, or why not?
<i>Question 17</i>	Do submitters agree that, if procured, generation TAs should be unconstrained in terms of offer prices for energy (as in the minimal CP option definition)? If you disagree what alternative would you propose and on what basis?
<i>Question 18</i>	Do submitters agree that symmetrical financial incentives that reward over-performance and recover costs for under-performance are appropriate for the CP options? If not, what alternative arrangement would you propose to deal with availability and unplanned outages, and why?
<i>Question 19</i>	Do submitters agree that under the CP options, the System Operator should be able to provide notice as required for operation of TAs? If not, what alternative arrangement to deal with notice would you propose and why?
<i>Question 20</i>	Do submitters agree with the proposal to require TAs to seek the System Operator's approval for any planned outages? If not, what alternative arrangement to deal with planned outages would you propose and why?
<i>Question 21</i>	Do submitters agree with the assessment that, under the CP options, no restrictions need to be placed on TA provider's ability to participate in the reserve energy arrangements? If not, on what basis do you disagree and what alternative arrangement would you propose?
<i>Question 22</i>	Do submitters agree with the assessment that no restrictions need to be placed on TA provider's ability to participate in the IR, CR, and MRDA markets? If not, on what basis do you disagree and what alternative arrangement would you propose?
<i>Question 23</i>	Do submitters agree that all of these tests are required, and if not why not? Do they need to be simplified, and if so, how would you do that?
<i>Question 24</i>	Do submitters agree significant reconciliation problems would arise with allocating capacity contracts based on metered load?

