Commission review of the IM's

Identifying problems with current IM's

NZIER report to MEUG

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Final

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1. Background

1.1. Objectives – what is important

1. Through its review of the Part 4 Input Methodologies (IM's) the Commerce Commission (Commission) has published a paper that invites contributions to assist them identify and define any problems that may exist with the current IM's. This paper is a follow up to their open letter on the scope of the review from February 2015 and their June 2015 Notice of Intention to review the IM's.

2. The problem definition paper sets out the Commission views regarding potential problems and issues with the IM's based on their experience of working with the IM's to date, as well as various feedback that they have received since 2010 and more recently following their open letter.

3. The Commission has listed nine topics. We focus our assessments on four of these topics:

   - risk allocation mechanism under price quality paths
   - future impact of emerging technologies in the energy sector
   - issues raised by the High Court on cost of capital
   - form of control for price quality regulated sectors.

   In addition we comment on the interaction between default (DPP) and custom price paths (CPP) and the cost effectiveness of the rules and processes for CPP applications. We note the Commission's guidance that it needs to work within the IM structure.

4. Our central argument regarding the need to change the IM's now rather than wait, is that emerging technology in the generation and storage of electricity is eroding the monopoly power of distribution businesses (EDBs). The availability of local generation and storage options highlights for us that the drivers of benefits for different groups of consumers from regulated network services is already breaking down. These changes undermine two of the key simplifying assumptions that support the IM building block methodology used to set price quality paths.

5. Firstly, the IM's implicitly assume that EDB services will continue to be a natural monopoly so the Commission needs to set prices for distribution services that deliver a fair return on EDB assets. We argue that emerging technology:

   - could change the use of the distribution network so that it is peakier but with lower energy throughput. This will aggravate the current misalignment between the structure of network costs (mainly the fixed costs of providing peak capacity) and the mix of charges (mainly variable related to energy delivered) that EDB's use to recover those costs.
   - creates new business models that are subject to competition. Regulating prices via the IM's to deliver a return on traditional

electricity distribution assets may impede the adoption of this technology to deliver competitive services and pricing to consumers.

6. Second is the assumption that regulating price paths communicates to all consumers the 'benefits' of restraining EDB monopoly power. We argue that:
   - the price paths do not actually signal the costs to the consumer of accessing regulated asset base because EDBs have applied different mixes of fixed charges (option to access) and variable charges based on use.
   - different groups of consumers have different levels of capacity to access emerging technology and reduce their exposure to EDB charges. Those consumers that are less able to reduce their reliance on the network are exposed to an increased share of the cost of underused assets

7. We accept that some of the issues described above, such as the consideration of transfer of costs from one group of consumers to another, cannot be addressed directly within the scope of the IM review. However we have included them in our submission as they are part of the root cause of what we expect will be a weakening of the capacity of the input methodologies to deliver the objectives of Part 4.

8. In addition to the pressures on the IM's created by emerging technology we also argue that there are existing unresolved problems with the IM's which include the following:
   - the WACC appears to be too high for both Transpower and the EDBs for the risk profiles of these businesses.
   - wide differences in the scale and scope of EDB operations along with the absence of performance benchmarking suggest that there is also wide variation in the efficiency of the EDBs
   - different tariff structures across EDBs for similar customer groups suggests that at least some groups of customers are not receiving the clear price signals about the relative efficiency of using the network supplied electricity as opposed to alternatives.
   - co-ordination of the principles and implementation of the IM's with the cost allocation approach adopted by the Electricity Authority (Authority).

9. We note that the Authority is currently reviewing the transmission pricing methodology (TPM). Their approach seeks to allocate transmission costs using proxies for ‘market-like’ arrangements. A key principle in the Authority proposals seems to be to allocate the costs of Transpower network on the basis of the option to access capacity rather than energy delivered.

10. For us the primary focus of the review should be to identify the changes to IM’s that will bring most improvements to consumer welfare.

11. The current IM's have a clear focus on limiting returns to regulated businesses to those that would be observed in a competitive market, but also on providing a high degree of certainty to regulated firms regarding how the Commission will apply the IM's. This objective is to provide regulated firms with some comfort

that their investment and operating decisions regarding long lived networks assets can be made with a tolerable level of regulatory risk.

12. For us, 5 years on from the implementation of the IM's, the secondary focus of this review should be whether the IM's are delivering network services in an efficient manner and are appropriate when thinking about productivity improvements from existing networks and investments in innovation. That is - it is efficiency, optimal network performance and services for consumers that matter more going forward.

1.2. Our approach

13. The aim of this report is to identify both current issues and the potential for problems in the future from, and for, the existing IM's. This is not a straight forward task with an established methodology. Nor do we see it as an opportunity to advocate a particular position now or for the future. We employ a number of analytical approaches, we examine evidence as appropriate and where we cannot progress our analysis further we pose particular questions in Appendix B about further lines of enquiry that we suggest should be undertaken by the Commission.

1.2.1. The environment

14. First up we briefly examine where the energy sector has come from since 2010 and also consider what the energy environment could look like in the future - this could be thought of as a narrow environmental scan. Here we pick up on some of the threads of analysis that we included in our memo to MEUG dated 20 March 2015. We also consider what is happening internationally in this regard.
15. As a precursor to being able to identify potential problems, part of this process will be to identify uncertainties and issues from the environmental scan - evidence them where possible and rate them for materiality and importance.
16. Then examine current regulation/IM’s in light of uncertainties and issues and given the nature of regulated networks, for example business models, asset management and costs, geographic, demographic and economic characteristics and the like. Here we are also interested in which regulated businesses have already started adapting to the changing environment under the existing IM's and hence whether there is prima face evidence of problems.
17. We also reference and analyse parts of the Commission's own 16 June 2015 paper that gives their initial view of problems and sets out the review process.

1.2.2. Scope problems from our analysis

18. To make the process of identifying/analysing potential problems tractable rather than be either too granular or too 'high level', we assemble and assess the issues and uncertainties that could impact on and with the IM's.

19. Thus, in a manner similar to the Commission, we group uncertainties and issues into what we see at this stage as being 'material' potential problem areas and scope the various dimensions of these would-be problems. We go into this early stage of the process with a partly populated list of issues and higher level problems that we identified in our March memo to MEUG where, for example, we suggested that:

- Fixed ‘revenue’ model of remunerating networks - likely lacks flexibility to changing industry circumstances
- Network costs are rising while costs of network alternatives are declining
- Economic signals through the system to consumers (pricing messages) do not reflect costs - the system now needs to compete with network alternatives
- Boundary issues are emerging - regulated/not regulated business models but not all EDB's are travelling in the same way (differences are often a mix of regional, scale and resources/competency factors)
- WACC is probably too high - risk and reward are not in balance
- The overall system is probably quite inefficient but it is hard to tell the extent of any problems here because the IM's are input controls (capex and opex) rather than results or output drivers.

20. For this submission we have grouped our assessment of the issues that should be considered in reviewing the ‘fitness for purpose’ of the IMs under three topics:

- potential effect of emerging technology on electricity distribution
- allocation of risk between EDBs and consumer groups
- efficiency of the pricing signals provided by EDBs

1.2.3. Potential pathways/solutions

21. We include a section towards the back of this report which suggests possible ways forward on how to further define problems with the IM's and possible remedies and solutions. This is of course predicated on our views regarding perceived problems as being accurate. We offer a mix of suggested pathways, for example:

- results based regulation may play a role
- use of reference models for network performance
- use the UK experience as reference
- use of CPP as 'flexible' tool for dealing with uncertainty and to overcome issues with EDB's starting in different places and having different development trajectories
- possible rationalise the number of EDB's

2. Context for the IM review

22. In this section we discuss key changes in electricity supply business models both over the last 5 years and the outlook for those technologies. Since 2010 the cost of solar PV and battery storage have fallen and examples of the potential effects of these and other innovations on electricity supply business models have emerged in overseas markets.

2.1. International scan

23. At a regulatory level overseas, questions have been raised about whether electricity markets, regulated or not, are meeting today's consumer needs and what sorts of changes are required to meet future needs. There is concern that if each of technology, markets and regulation do not together keep pace with the accelerating rate of change then suboptimal outcomes for all concerned could well result. Examples of the scale scope of change regulators overseas are dealing with are discussed below.

24. California, along with Australia and Germany, appear to have the highest levels of installed local generation. California is however grappling with a series of technical system operator issues as grid scale wind and PV volumes balloon. They have also recently initiated a number of policy and regulatory improvements to deal with changes both within the grids, and on the demand side.

    - Increased **focus on flexible resources.** The California Public Utilities Commission (CPUC) has adopted a flexible capacity framework to start in 2015 load serving entities (LSEs) to procure a certain level of flexible capacity when meeting resource adequacy needs.
    - **Storage mandate.** CPUC has mandated that the state's three investor-owned utilities procure 1.325 GW of energy storage at various interconnection levels (transmission, distribution, customer-sited) by 2020.
    - **Market design enhancements for intra-hour scheduling.** In 2014, CAISO implemented a 15-minute market for generators, imports, exports, and participating loads as part of its compliance of requiring intra-hour scheduling options to aid the integration of renewable resources into the grid.
    - **Time-of-use pricing.** California has enacted legislation enabling the CPUC to authorize utilities to default (with the option to opt out) residential customers to a time-of-use rate schedule starting in 2018. Under time-of-use rates, customers' time-varying rates will reflect variation in the cost of generation (unlike traditional rate structures), and may be more likely to shift consumption hours away from periods when peak generation is required from dispatchable units, thereby reducing the amount of resources necessary to meet load.
    - **Demand response.** California enacted legislation in 2014 directing the CPUC to include demand response in its assessment of resource

adequacy requirements and to establish a set of rules and tariff policies to encourage the efficient and cost-effective deployment of demand response resources.

25. Quite clearly this is a package of measures that has altered how the energy sector in California is regulated as a result of technical and demand side changes.

26. Even though Australia now has more than 1,800 wind turbines installed and 1.4m rooftop solar systems are on homes and businesses, the overall share of renewable energy in Australia’s electricity mix remains modest. In 2014 it was just 13.5% of the total power supply, with almost half of that coming from decades-old hydro electricity schemes. Queensland is well ahead of the other states with residential PV installations.

27. Despite these high levels of local generation, and PV grid parity, distribution businesses in Australia are still seeking regulated revenue determinations from the AER that are in line with previous levels. The distributors are also seeking approval to add to their RAB by investing in new technologies - grid storage to off-set network investment. To date the AER have ignored these applications but have at the same time slashed traditional network investment to 'make the networks (mainly NSW) more efficient and to provide benefits from the productivity improvements to consumers'.

28. In other countries Government policy has set out specific growth targets for local, renewable generation. A good example here is Germany where the level of intermittent renewable generating capacity (wind and PV mainly) is now at a level that it appears their traditional base load generators are not earning enough revenue to survive. Further growth in these variable output generation resources suggests that either German consumers will need to make adjustments regarding how they use electricity or the government regulators will need to make adjustments regarding how electricity is priced to pay for the flexible use of generating and distribution resources that is now needed. As is becoming the case elsewhere this situation can be partly relieved by installing grid scale batteries when they become available.

29. In the face of extensive growth in local generation (mainly PV), the Hawaiian electric utility company, HECO, has adopted additional interconnection requirements for its systems including small-scale rooftop solar photovoltaic systems. The utility is planning to deploy smart meters, which would provide more data to help guide day-to-day grid management decisions and is investing in weather forecasting systems and distributed energy analysis and management technology. It is also installing grid-scale battery systems, incorporating demand response, and taking other steps to manage impacts from solar PV.

30. Regulators in other countries are examining in detail how their energy sectors are performing and whether changes to regulations are required in light of this disruption – we believe that this is the opportunity for the Commission to do the same.

31. Developments in technologies and the economics of local generation appear to have moved ahead of grid technology/economics in many parts of the world

prompting similar questions. It seems that the technology and costs of energy storage, distributed generation and micro-grids warrant immediate consideration, such that a change away from the traditional regulatory models for electricity networks are being considered as necessary in the near future.

32. A more detailed consideration of regulatory responses to these developments overseas is included in Section 3 while Appendix A has more detail on the international growth patterns of solar PV and batteries in particular.

33. Certain of these technical and consumer side developments are more established overseas and are proving helpful when considering the potential for these changes to create issues and problems with economic regulation in New Zealand.

2.2. Application to New Zealand

34. When the IMs were being developed prior to 2010, there was little prospect of the electricity industry being subject to the sorts of disruptive changes that are starting to emerge. The potential for change was talked about but the IMs were developed in an energy system where, for instance, nearly all electricity was generated far from the point of use, transported by the grids and offered for sale and purchased in the wholesale market.

35. EDB's had asset management plans that assumed peak demand and energy would be transported across their networks in volumes that were correlated with positive GDP and population growth and that energy consumers had little choice but to pay. Demand growth of both energy and capacity was steady and positive and investment in improvements to the distribution grid was likewise steady and predictable. Investment in the transmission grid was somewhat lumpier with a steep increase in capex from 2007. An efficient EDB was one that managed the balance between right sized increments and demand growth with current users paying for future use of the networks.

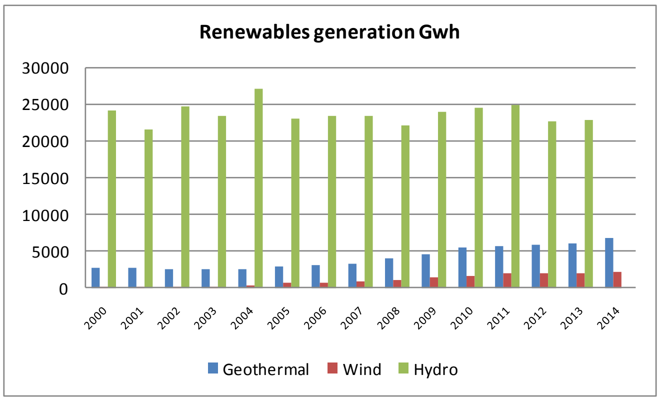
36. This has now changed and will continue to do so, requiring a re-consideration of the risks and incentives for both networks businesses and for consumers of network services.

37. Declining demand growth for energy, climate change concerns, strong growth of renewable local generation of electricity, energy storage systems and demand management, as well as the use of smart technology in the operational management of grids have all combined to jump start what is now regarded as potentially the most profound changes to the energy industries since the initial development of the networks.

38. These changes appear to be neither short term nor cyclical. They are structural, long term and are changing the economics of the energy system. Two examples serve to demonstrate our points. Over the last ten years wind and geothermal generation have both emerged with material growth in output capacity, such that they have contributed to the closure of the coal generation sites at Huntly by Genesis as well as the two gas generation plants near Auckland.[1]

1 Contact announced 17 August that they were shutting Otahuhu plant down while MRP will close the Southdown gas plant at the end of 2015.

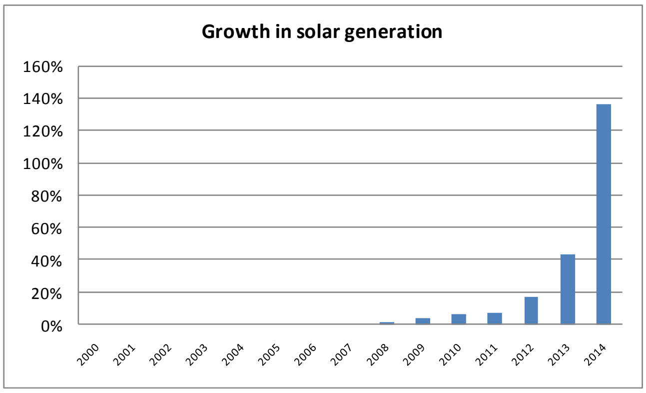
Figure 1 Renewable generation



Source: NZIER analysis MBIE Electricity 2015 data

39. In the same way as with earlier international market experience, data recently released on energy generation and consumption in New Zealand by MBIE[2] shows a significant but not unexpected jump in growth in the volume of solar PV energy generated into the grid in the 2013 and 2014 years (figure 2 below).

Figure 2 Solar generation growth New Zealand



Source: NZIER analysis MBIE Electricity 2015 data

40. These types of change are examples of the beginning of a process of change to both business models as well as the economics of the industry 'systems' through the process of technical change.

41. The technical changes we refer to specifically affect supplier and consumers incentives for investment in, and rewards from, new technology. This will change the established distribution of risks and costs across consumers and service providers.

42. It seems to us that not only has the distribution of risk changed but other, different, competitive markets are emerging for some types of network services

[2] http://www.med.govt.nz/sectors-industries/energy/energy-modelling/publications/energy-in-new-zealand/Energy-in-New-Zealand-2015.pdf

(for example local generation and storage choices are growing for individual consumers who want to reduce their reliance on the 'grid').

43. The task facing the Commission in 2015 is therefore not the same one that they faced in 2010. The mechanisms, including the IMs, through which the Commission can achieve its objective of ensuring the pricing charged by EDB's delivers long term benefits to consumers have turned out to be quite indirect in practice. It is hard to tell how EDB's deliver long term benefits which attenuates an important link between the overall revenue cap and EDB's pricing signals to consumers.

44. It appears that not all EDB's are in the same place in this regard. Some, such as Orion seem to be saying that they believe that the future will be very much like the past and that they can accommodate change regardless. Other such as Vector are actively embracing technical change and have lines of business that sell and install PV systems including Tesla storage batteries. Transpower is actively looking to demand side response as a technique to manage network investment but many EDB's appear to be not especially engaged or have different stages of technical and demand side developments in process.

2.3. What emerged from our scan

45. We believe that the IM review provides the opportunity for us all, to take stock of whether the existing IMs will limit or promote the benefits to consumers that will flow from these changes. We believe that greater benefit will arise from a deliberate 're-tooling' of the IM regulatory structures that currently appear to favour certainty over improved consumer outcomes.

46. So where should the focus be. What are the material problem areas that we see at this stage and what evidence do we have regarding these problem areas. In the same manner as the Commission we summarised and grouped the issues that emerged from our scan and analysis into 'perceived problems' for further assessment.

47. Some of the issues that we bring into focus here cannot be adequately scoped as 'problems' without further work to consider the lines of enquiry that we suggest in Appendix B. We have however bundled the various issues into three areas of potential problems, as follows:

    - 'The energy system is experiencing material change'
    - 'System changes result in a need to reallocate risk'
    - 'Economic signals in system need to be efficient and reflect where risks are located'

48. We see system changes unfolding here, or likely to unfold that are now well visible overseas. Choices regarding energy availability and use are widening for some consumers but there is no particular pattern and the scale of change is smaller than elsewhere. That is not to say changes will not take place or that they will emerge as particular problems for the existing IM's, change is less visible here than elsewhere.

49. For us, the IM industry forum at the end of July was especially helpful because it illustrated the diversity of views regarding the dimensions of technical and demand side changes in New Zealand energy systems. It also identified that industry participants (Transpower, EDB's and retailers in particular) are approaching these changes in different ways and from mostly different starting points. We noted for instance that Vector has and is embracing this change and they see a role for themselves as taking the benefits from the technology to their connected customers.

50. The next sections bring the focus onto these three problem areas.

3. Problem area 1

Perceived problem: energy system changes

Changes to the energy system that were not visible, or expected, when the IM's were developed in 2010 are occurring both within the regulated parts of the network businesses as well as outside of regulation. These changes are expected to bring significant benefits to consumers and provide opportunities to the network businesses. It is not clear whether the current IM's will promote or hinder the delivery of consumer benefits from these changes.

Discussion

51. The system changes that we refer to here are potentially wide ranging - some were discussed and evidenced previously while other changes are yet to manifest themselves here in New Zealand.

52. The penetration of variable energy production, the growing two way trade of electricity and new demand patterns indicate to us that energy storage will play an increasing important role in the energy system.[3] Because the effects of storage will be felt across the system, this may be the catalyst for system participants (including regulators) to take on a more active role. While it is important that the IM's are able to meet their Part 4 objectives it is also important that they do not stand in the way for the dynamic gains from this type of development.

53. Even where benefits are measured against alternative solutions – such as demand-side management, back-up generation and flexible loads, the role of storage is evident in the value chain, from end-user to distribution, transmission, and markets. In particular, batteries offer cost-efficient solutions for innovative models of decentralized energy systems. They can foster the development of micro-grids, while the home storage market combined with PV allows for an increase in self-consumption. These developments could well take place in 'market space' outside of the regulated network environment.

54. Distributed energy storage has the capacity to create massive reductions in peak demand levels on electricity networks. This is because it can remove the few peak periods that create the need for much of the capacity. Not only will energy consumption fall but so will the need for network capacity. Replacing and augmenting existing networks is going to be a very risky business because those investments are at significant risk of being stranded. It is also likely that, in the future, networks will shrink, as off-grid alternatives to long lines in remote areas will become more affordable and reliable

55. So, there is going to be change but we are not sure when or what! There is a balancing act here for both the Commission and the policy makers to accommodate the potentially material gains from these changes and the desire

[3] We discuss the emerging and established developments with local generation and storage in Appendix B.

for short term stability within the application of energy sector economic regulation.

Table 1 Assessing disruptive technology impact

Use of electricity networks		Connection impact	Effect on grid cost recovery and investment
Volume - how much consumer demand is locally generated?	All	Disconnect from the grid	Stranded network connection and reduced energy throughput.
	Most	Remain connected for peak use and contingency	Wide gap between variable c/kWh charge and fixed connection cost Risk of stranding if price of PV falls or other back –up options such as batteries become more efficient. Need capacity charge and contingency charge to recover connection cost.
	Some	Remain connected for peak use and bulk of energy supply	Widening gap between variable c/kWh charge and costs Move to capacity charge to recover connection costs
	Minor amount or nil	Remain connected for normal supply	Current model continues. Exposure to costs of stranded assets that are not recovered from other consumers
Location - where is electricity used?	On-site as generated	Reduces volume of electricity delivered - does not flatten peaks	Reduced demand –off-peak – widens gap between variable c/kWh charge and fixed connection cost
	Stored in battery on site and used on site	Flattens peaks and reduces volume of energy through the grid	Reduced peak demand and reduced use of the network.
	Sent into the EDB network as generated and used by other consumers	Localises the supply of electricity but does not affect requirements for peak capacity	Reduced volume of electricity transported through the grid without a reduction on dependence for grid to meet peak demands
	Sent into the EDB network and stored in batteries	Peaks are flattened for the grid but not the EDB network	Flattened peak demand and reduced electricity transport for the grid but not for EDB networks. Battery storage could be a new business stream for EDB.

Source: NZIER

56. In responding to these potential changes we suggest that the Commission needs to consider two questions. The first question is whether sector regulation should lead or respond to these types of developments. It is possible that these changes

will be material and happen sooner rather than later bringing benefits to suppliers and consumers. If this occurs and the Commission are not prepared with appropriate changes to Part 4 and the IM's, then there would likely be competitive detriment for both sides.

57. The next question for the Commission is what if any material changes to the regulatory system in the short term. If material changes are necessary it seems the Commission has two options at this stage - re-tool the IM's in anticipation of system change or be prepared to make urgent amendments to the IM's as system change unfolds. The scale and nature of such urgent amendments will guide thinking about the need for a more major revamp of Part 4. As we say, this is the balancing act that the Commission needs to contemplate in this IM review through 2016.

4. Problem area 2

Perceived problem: assignment of risk.

Current IM's were developed to assign risks and provide for returns based on the shape of the energy sector 'system' that existed in the period 2007 to 2009. Conceptually, network operating risks remained with the network operator; return to capital risk was transferred via the regulatory process to consumers, likewise opex risk, while governance risk (making a strategic mistake) was split between the regulated business and the Commission. Provided the system stays in that previous shape then conceptually the IM's may still be suitable tools to go forward with. We don't think that this is the case, in fact they need re-tooling because it is too late, change is underway.

Discussion

58. The key problems facing the system environment in 2010 were improving reliability and ensuring forecast increased demand for electricity could be met. Adoption of solar PV and battery storage were theoretical possibilities driven be environmental energy efficiency goals rather than as a competitive alternatives to traditional electricity supply models.

59. The original RAB and WACC mechanisms within the IM's that were used to quantify risk and returns also remain. The WACC IM is a traditional risk/reward tool for regulating business that we argue needs to be reconsidered as the shape of those regulated businesses change and competitive options for the supply of energy services emerge. Without change to the allocation of risk and possibly a review of the WACC IM, the current arrangements maintain inappropriate incentives to continue to add assets to the RAB, some of which could likely be used to provide competitive services outside of the RAB. This just increases the offset of risk onto consumers.

60. Consumers appear to have already shouldered more of the investment risk because they had little choice – we question whether this is sustainable in the near term as their choices to continue to participate as they did then have changed. This of itself should be sufficient to justify the need to assess whether the system delivers welfare enhancing outputs for consumers who have born most of the risk to date and what role the IM's should play in this risk redistribution.

61. We argue that there is already evidence of increased risk of long term under use of electricity network assets – for instance we believe that there is a real near term risk of long term under use of recent grid upgrades due to flattening demand and from the wider, growing presence of distributed generation of various types. This raises the question of who bears this investment risk in the grid and the role of the current IM's in this changed environment.

62. The reallocation of risk needs to be adaptive to accommodate the outcomes that will flow as the 'Problem area 1: energy system changes' unfold over time. This will likely prove challenging for the Commission however;

- we also suggest that these disruptive technologies will create distinct challenges for the Commission even if they continue to use the existing IM approach to deliver its objective of ‘promoting outcomes that are consistent with outcomes produced in competitive markets’.
- we point out that the transition period of disruptive change is not particularly well described by standard perfect competition models. There will be a time of transition where part of the EDB business will be more 'natural monopoly' and part will be outside that definition but not necessarily part of a competitive market.
- in light of this, the Commission may want to consider outlining a set of principles about how it will consider allocation of the costs and risks of disruptive change between 'monopolies' and consumers and also perhaps, a materiality threshold for considering the effects of disruptive change within the IM's.
- while we recognise that disruptive change can ‘strand’ assets we suggest that it is difficult to predict what assets will be stranded and when. The Commission may wish to prepare for this eventuality by considering:
  - the assumptions about demand growth in EDB investment plans and requesting specific comment on the planning assumptions for disruptive technology, or sensitivity analysis around the investment requirements
  - scenarios for how the risks and costs of stranded or under-employed assets should be allocated between network service providers and consumers.
  - what tests the Commission would apply to determine if EDB investment in disruptive technologies would or would not be within the scope of the regulated asset base.

63. Certainty for regulated networks as a Part 4 objective sits uncomfortably with the system environment that we have described here and especially with the heightened uncertainty that these networks face (uncertainty in both the regulated and unregulated parts of their businesses). We believe that the Commission cannot use the past as the indicator of the future and continue to offset the risk of getting it wrong onto consumers.

Form of regulatory control

64. The form of control (price control, revenue cap or another approach) is merely the tool for applying and managing the risks and incentives that flow from the objectives of the regulation. The form of control is important however, because it is the frame for how the IM mechanisms will drive the appropriate outcomes in the regulated business.

65. Our first issue here relates to the starting point for the form of regulation – the 2010 start point was prices as at 31 March 2010 with no sense as to whether those prices (and the economic performance on which they were built) were efficient or not. Performance benchmarking the regulated businesses will be an

important guide to determining the start point and informing the form of regulation.

66. Second question to consider is who bears volume risk and whether specific investment incentives, or other performance enhancing incentives, are required.

67. Others overseas are facing these same questions – some have already figured out what to change and how to make sure that have energy sector regulation that is adaptive as the changes move forward. We need to learn from their work.

68. For instance most energy regulators in the EU have moved away from cost plus building block price/revenue cap regulation and now use regulatory tools that are targeted at network performance (efficiency, reliability, service levels) and fair prices for consumers. As it should, this approach is placing pressure on network owners and financial returns to drive performance improvements.

Table 2 Form of regulation – EU electricity distribution

	Belgium	France	Germany	Italy	Spain	Sweden	UK	Holland
Form of regulation	Cost plus	Incentive	Incentive	Cost & incentive	Benchmark & rev cap	Income based	Price cap	Incentive
RAB based	yes	yes	no	no	yes	no	yes	no
Efficiency factor	no	yes	1.5% pa	yes	yes	1% pa	yes	2.3% pa
Inflation allowed	partly	partly	CPI-1.5%	In WACC	yes	yes	yes	yes
Volume risk	no	no	no	no	no	no	no	no
Investment incentives	no	no	no	yes	no	yes	yes	yes
Other incentives	yes	yes	yes	yes	yes	yes	yes	yes

Source: NZIER & EY France

69. When thinking about incentives for productivity improvements and innovation in energy sector economic regulation it is however important to include consideration of efficient decision making, operations and the use of 'non' network productivity improvements to drive welfare gains for consumers and producers from within the regulated monopoly business.

5. Problem area 3

Perceived problem: economic signals

The pricing of distribution services should reflect the cost of the services provided. The principles of efficient network pricing suggest that prices need to be set to recover the costs of the existing network assets with as little effect on consumer demand as possible while also sending a clear signal about the long run marginal cost of the network. These principles ensure that consumers receive accurate signals about the cost of using the network and therefore have the right information to maximise their welfare.

In practice nearly all distribution service charges (along with transmission charges) are bundled with charges set by the retailer that combine the costs of electricity generation and retailing (set in competitive markets) with cost of transporting electricity (set In regulated markets) This blurs the price signals about access to the network and use of the product carried by the network.

The application of efficient network service pricing principles becomes more important when innovations create the opportunity for groups of consumers to change how they use network services. Also both the Commerce Commission and the Electricity Authority are setting principles for the recovery of network costs from consumers for the long term benefit of consumers while providing sufficient stability for the investor

Discussion

70. We need to consider a series of issues about the economic signals from the existing system before we can scope the size and shape of this problem and develop solutions as needed. In this section we summarise the available information on EDB charging and consider the following questions:

- does the current charging seem to reflect the cost of providing access to a network when it is based on electricity flows through the network
- how would the allocation of costs change if the usage pattern of the network altered
- how consistent are the EDB pricing principles with the principles applied by the Electricity Authority in its development of the transmission pricing methodology (TPM).

Analysis of the data

71. We have analysed the revenue collected by charge type as disclosed by EDBs [4] and classified the charges as fixed (per day/month, unit of capacity or peak demand) or variable (linked to energy used per hour). Despite the wide definition of fixed relative to variable charges, our analysis indicates EDB

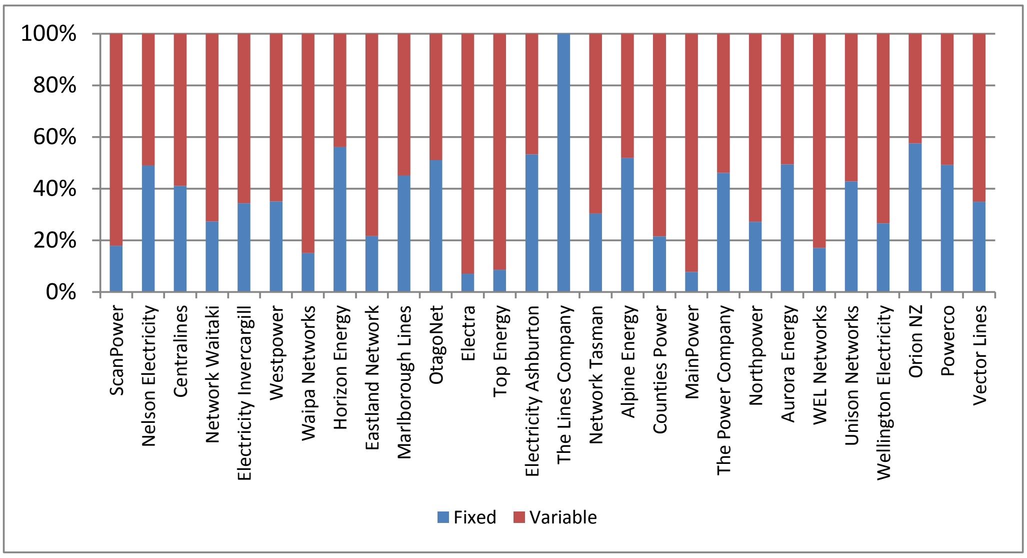
[4] 8(ii): Line Charge Revenues ($000) by Price Component of EDB Information Disclosure for the year ended 31 March 2014, published by the Commerce Commission.

revenue is strongly linked to the energy that flows through the network rather than the right to be connected to the network.

72. For EDBs as a group only 36 to 40 percent of EDB revenue is obtained through fixed charges but within the group there is wide variation in the proportion of revenue collected through fixed charges. (Part of the reliance on variable rather than fixed charges is driven by EDB application of the Low Fixed Charge Regulations).[5] The variation within the group does not seem to be correlated with the size of the EDB (as measured by number of ICPs, or energy delivered). The following figure 3 illustrates the difference in the mix of fixed and variable charges for the EDBs presented in order of increasing distribution revenue (lowest at the left to highest at the right).

Figure 3 EDB Revenue mix

Proportion of fixed and variable revenue for year ended 2014



Source: NZIER analysis of EDB information disclosures

73. The following table 3 shows the difference in scale between EDBs. Vector, PowerCo and Orion together account for just over 50 percent of both the total energy supplied and the total EDB revenue. However the proportion of fixed charge revenue differs by more than 20 percentage points (35 percent for Vector to 54 percent for Orion).

[5] There are four major variants in the approach used by EDBs to complying with the Low Fixed Charge regulations.

Table 3 EDB Energy supplied and revenue mix

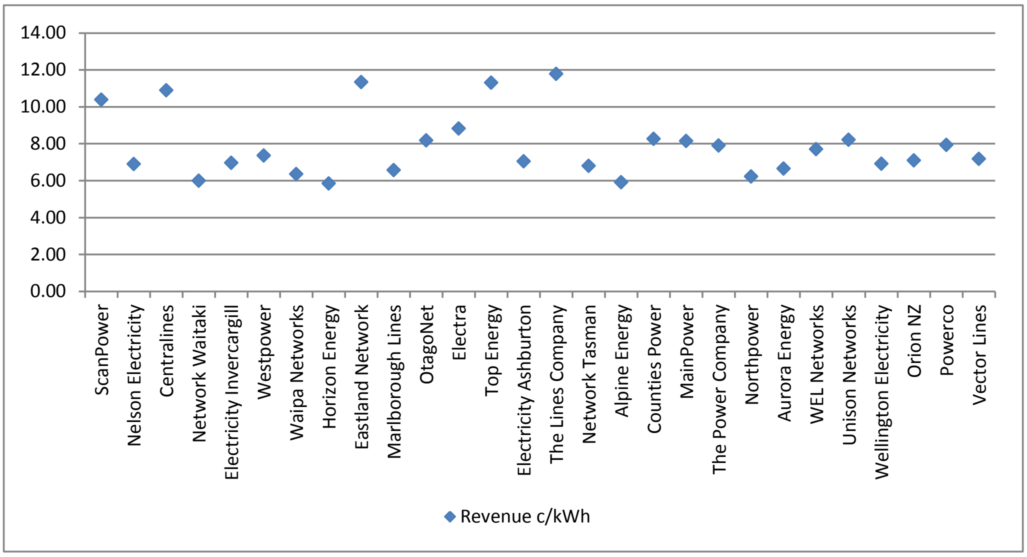
Year ended 31 March 2014

EDB	Energy Supplied		Revenue			
	GWh	Share of total	Fixed ($m)	Variable ($m)	Total ($m)	Share of total
ScanPower	77.7	0.3%	1.4	6.6	8.1	0.4%
Nelson Electricity	142.2	0.5%	4.8	5.0	9.8	0.4%
Centralines	102.2	0.3%	4.6	6.6	11.1	0.5%
Network Waitaki	231.5	0.8%	3.8	10.1	13.9	0.6%
Electricity Invercargill	257.9	0.8%	6.2	11.8	17.9	0.8%
Westpower	265.9	0.9%	6.9	12.7	19.6	0.9%
Waipa Networks	347.3	1.1%	3.3	18.7	22.1	1.0%
Horizon Energy	512.8	1.7%	16.8	13.2	30.0	1.3%
Eastland Network	280.2	0.9%	6.9	24.9	31.8	1.4%
Marlborough Lines	362.4	1.2%	10.7	13.1	23.8	1.0%
OtagoNet	399.8	1.3%	16.7	16.0	32.7	1.4%
Electra	401.9	1.3%	2.5	33.0	35.5	1.6%
Top Energy	323.8	1.1%	3.1	33.5	36.6	1.6%
Electricity Ashburton	522.7	1.7%	19.6	17.2	36.8	1.6%
The Lines Company	314.6	1.0%	37.1	0.0	37.1	1.6%
Network Tasman	589.8	1.9%	12.2	27.9	40.1	1.8%
Alpine Energy	715.9	2.3%	22.0	20.4	42.4	1.9%
Counties Power	524.6	1.7%	9.3	34.0	43.3	1.9%
MainPower	559.5	1.8%	3.5	42.0	45.6	2.0%
The Power Company	684.3	2.2%	24.9	29.2	54.0	2.4%
Northpower	964.0	3.1%	16.3	43.7	60.0	2.6%
Aurora Energy	1,250.3	4.1%	41.1	42.1	83.1	3.7%
WEL Networks	1,201.3	3.9%	15.7	76.9	92.6	4.1%
Unison Networks	1,550.2	5.1%	54.5	72.8	127.3	5.6%
Wellington Electricity	2,368.1	7.7%	43.4	120.2	163.6	7.2%
Orion NZ	3,026.6	9.9%	123.3	91.3	214.6	9.4%
Powerco	4,366.7	14.3%	170.1	176.1	346.2	15.2%
Vector Lines	8,259.6	27.0%	206.5	385.8	592.4	26.1%
Total	**30,603**		**887**	**1,384**	**2,271**	

Source: NZIER analysis of EDB information disclosures

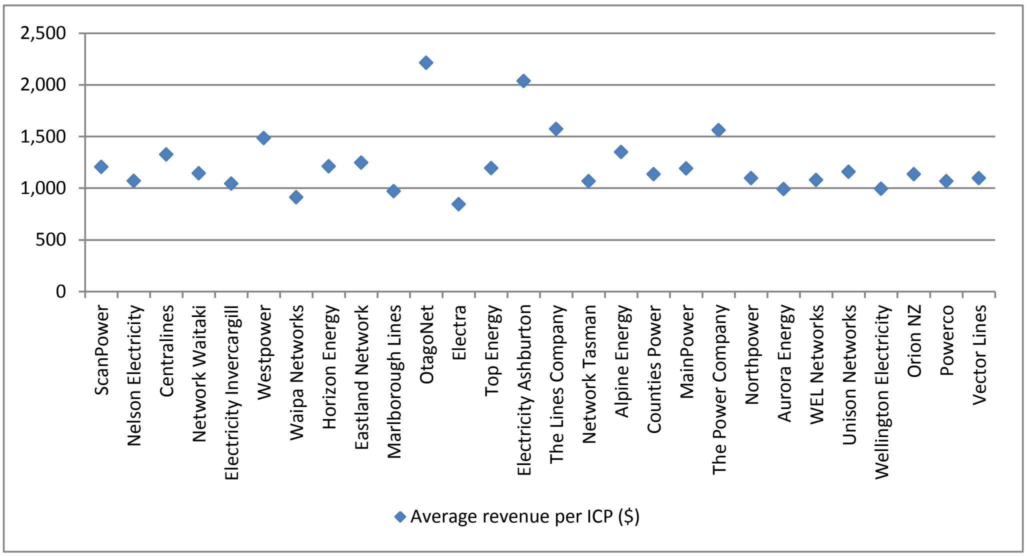
74. There is also wide variation in both the average revenue per unit of energy supplied and the average revenue per ICP.

Figure 4 EDB revenue and scale of energy supplied



Source: Source: NZIER analysis of EDB information disclosures

Figure 5 EDB revenue and scale of customer base



Source: NZIER analysis of EDB information disclosures

75. The relatively high proportion of EDB revenue that is dependent on energy consumption suggests that EDBs in general are exposed to the risk of falling revenues if energy consumption declines. A detailed examination of the EDB costs is beyond the scope of this paper but it appears that most of the costs are fixed and affected much more by the option to access a given level of supply capacity rather than the amount of electricity.

76. The variation in revenue mix and scale across the EDBs suggests different price responses to changes in consumer use of electricity in response to new

technology. Those EDBs most reliant on variable charges are also most likely to be exposed to loss of revenue from consumers that adopt solar PV and battery technology and have a charging structure that is less suited to increasing fixed charges to recover the fixed cost of providing the option to connect to the grid.

77. The RAB and WACC are the major levers in the IM tool kit and involve material judgement calls by the Commission, but they are neutral in respect of the mix of charges EDBs use to recover their costs and are not well suited to encouraging EDBs to set prices that signal the true costs of consumers connecting to the network.

78. Short term use of the distribution network capacity for different periods for different types of services suggests to us that pricing could be time based, Time of Use under a services specific structure that reflects the performance and quality of the capacity service that the consumer requires. For example the capacity service provider, including the network business, only gets paid for the capacity that is actually used.

79. We think of this as 'smart' distribution pricing that can accommodate known disruptions and adapt as new service offerings are developed. It would be helpful and sensible to attend to this sooner rather than later as it will impact not only the Commission IMs review but also the way the Electricity Authority will go about its efficient pricing project.

80. We suggest that the Commission increase the likelihood that monopolies and consumers are sending and receiving pricing signals that encourage 'efficient' adoption of disruptive technology by:

   – reviewing the efficiency of the different pricing practices followed by lines companies and in particular how well the different menus of fixed , capacity (based on peak demand) and variable (based on the total amount of electricity supplied) reflect the cost of the services provided by EDB's.
   – initiating discussion on how network pricing should be set for consumers that remain connected to the network but substantially reduce either the total amount of electricity consumed or change the profile of their peak demand

81. In this regard, we believe the following lines of enquiry would be helpful to the Commission IM review and to any review of system pricing arrangements:

82. To what extent are prices that consumers face cost reflective and subsidy free and what do the resultant signals mean for the welfare of different consumer groups? Here we would want to examine how energy services are defined and priced at both wholesale and retail level with the objective of developing a flexible and efficient approach to setting regulated revenues and prices. For instance two-way energy flows from local generation will have an impact on how ancillary services are defined and how they should be efficiently priced.

83. To make progress with these types of issues we suggest that as a part of the IM review the Commission increase the likelihood that monopolies and consumers are sending and receiving pricing signals that encourage 'efficient' adoption of disruptive technology by:

– reviewing the efficiency of the different pricing practices followed by lines companies and in particular how well the different menus of fixed , capacity (based on peak demand) and variable (based on the total amount of electricity supplied) reflect the cost of the services provided by EDB's.
– initiating discussion on how network pricing should be set for consumers that remain connected to the network but substantially reduce either the total amount of electricity consumed or change the profile of their peak demand

6. Other potential problems

84. The Commission’s problem definition paper outlines the views for change in aspects of the IMs within the current “one-size fits all” IM framework. However EDBs vary in size and market conditions for their core electricity network businesses. In addition some EDBs have already developed substantial business in unregulated parts of the energy supply value chain. The disruptive technology described in section2 of this report will provide EDBs with both the opportunity and the incentive to offer new or expanded unregulated energy supply services. This spread of activities may also be challenging for the governance and management of EDBs

85. These changes will make it harder for the IM approach to reliably separate the assets and costs of EDBs into monopoly activities that require regulation and activities that are subject to competition and do not require regulation. This issue cannot be resolved by tweaking the IM's

6.1. One size fits all regulation

86. In the previous section we have illustrated the difference in scale and revenue mix for the EDBs. The EDBs also have vastly different perspectives on both the future demand that their networks will need to meet and the extent to which the outlook for their networks reflects recent experience.

Table 4 Energy supplied

Recent actual and forecast annual rates of change

EDB	Actual growth			Forecast	
	2008 to 2014	2010 to 2014		2014 to 2018	2015 to 2019
Alpine Energy	1.2%	-0.4%		2.8%	2.1%
Aurora Energy	-0.3%	-0.6%		1.0%	1.8%
Buller Electricity	5.1%	5.1%		1.4%	4.9%
Centralines	-0.5%	-1.3%		0.8%	0.9%
Counties Power	2.0%	2.5%		1.3%	6.4%
Eastland Network	-0.2%	0.0%		0.6%	0.3%
Electra Limited	0.0%	-0.9%		0.8%	0.7%
Electricity Ashburton	1.5%	-0.3%		3.0%	2.0%
Electricity Invercargill	-0.6%	-1.6%		0.5%	0.5%
Horizon Energy	-0.9%	-1.3%		0.0%	0.0%
Mainpower	2.2%	2.0%		3.1%	3.8%
Marlborough Lines	0.7%	-0.4%		1.5%	
Nelson Electricity	-0.9%	-0.9%		1.0%	0.5%
Network Tasman	-0.1%	0.5%		1.1%	0.5%
Network Waitaki	0.1%	-1.0%		1.7%	0.8%
Northpower	-0.1%	0.4%		0.2%	1.0%
Orion	-0.7%	-2.0%		1.3%	1.4%
OtagoNet	1.8%	1.0%		1.2%	0.4%
Powerco	12.6%	0.4%		0.6%	0.7%
Scanpower	-2.4%	-1.7%			
The Lines Company	0.7%	0.3%		0.5%	1.4%
The Power Company	1.4%	0.6%		0.5%	0.6%
Top Energy	0.0%	-0.3%		0.7%	1.0%
Unison Networks	-0.2%	-0.8%		4.8%	4.7%
Vector Lines		-0.2%		0.0%	0.3%
Waipa Networks	1.4%	0.7%		2.8%	1.2%
WEL Networks	0.6%	0.8%		1.7%	1.7%
Wellington Electricity		-1.4%		0.8%	-0.5%
Westpower	1.4%	-2.5%		1.6%	3.1%
System estimate	1.4%	-0.3%		1.0%	1.1%

Source: NZIER analysis of EDB information disclosures

Table 5 Maximum coincident peak demand

EDB	Actual Peak demand (MW)		Forecast		Forecast vs Actual (2010 to 2014)	
	2008 to 2014	2010 to 2014	2014 to 2018	2015 to 2019	2014 to 2018	2015 to 2019
Alpine Energy	123.0	120.4	137.6	143.2	14%	19%
Aurora Energy	241.0	240.0	251.0	246.5	5%	3%
Buller Electricity	11.5	11.5	13.3	15.2	15%	32%
Centralines	21.0	21.0	21.0	21.2	0%	1%
Counties Power	107.2	107.2	102.8	143.0	-4%	33%
Eastland Network	53.3	53.3	60.0	60.0	13%	13%
Electra Limited	103.6	103.6	100.9	103.0	-3%	-1%
Electricity Ashburton	154.5	154.5	178.6	175.2	16%	13%
Electricity Invercargill	66.2	66.2	68.2	65.3	3%	-1%
Horizon Energy	88.2	88.2	95.3	86.1	8%	-2%
Mainpower	100.0	100.0	115.0	114.0	15%	14%
Marlborough Lines	71.0	71.0	75.4	76.5	6%	8%
Nelson Electricity	34.2	33.6	33.7	33.8	0%	1%
Network Tasman	151.9	151.9	151.0	148.0	-1%	-3%
Network Waitaki	51.4	51.4	61.4	62.4	19%	21%
Northpower	168.0	168.0	177.0	179.0	5%	7%
Orion	631.6	631.6	618.0	630.0	-2%	0%
OtagoNet	56.4	56.4	57.8	50.0	2%	-11%
Powerco	757.1	757.1	773.0	779.3	2%	3%
Scanpower	17.4	16.6	19.5	14.8	18%	-11%
The Lines Company	56.0	56.0	55.4	52.2	-1%	-7%
The Power Company	117.9	93.4	151.3	152.0	62%	63%
Top Energy	57.6	57.6	43.2	48.0	-25%	-17%
Unison Networks	301.2	278.0				
Vector Lines	2,031.3	1,927.0	1,836.2	1,891.0	-5%	-2%
Waipa Networks	71.7	71.7	78.7	76.6	10%	7%
WEL Networks	262.1	262.1	275.0	285.2	5%	9%
Wellington Electricity	614.3	614.3	576.0	542.8	-6%	-12%
Westpower	37.0	37.0	35.2	27.1	-5%	-27%
System estimate	**6,020**	**6,020**	**6,155**	**6,217**	**2%**	**3%**

Source: NZIER analysis of EDB information disclosures

6.2. Regulatory set up

87. The current regulatory system is designed to deliver consumers the benefit of competitively priced electricity supply and distribution services by:

    - ensuring workable competition between providers at both ends of the supply chain (generators and retailers) – the responsibility of the Electricity Authority
    - regulating the price/revenue of 'natural monopoly' suppliers - Transpower and the lines companies, so that they deliver outcomes that would be delivered if a competitive market existed. This is the responsibility of the Commerce Commission.
    - ensuring that the quality of the services, including availability and reliability of supply, meet stakeholder expectations – a responsibility that is shared between the Authority and the Commission, where the allocation of the responsibility between these regulators is allocated as issues, such as reliability standards, arise.

88. This regulatory approach 'works' if the activities of providers in the supply chain remain within the boundaries set by the regulation (especially the IMs) so that the scope of each regulators task is clear and separate. We suggest that this regulatory approach:

    - is already under pressure to deliver its consumer benefit objective because of a mismatch between supplier plans for network investment and the flattening of electricity demand as well as the lack of evidence of the contribution of investment to network reliability or consumer willingness to pay for reliability.
    - is likely to face increased difficulty in achieving this objective as disruptive generation and demand management technology increases the risk of stranding network assets while some network pricing practices send consumers mixed signals about the relative costs of existing and disruptive electricity supply options.

89. Because it fundamentally alters the way networks investment and operations are conducted, the wide spread adoption of battery technology may be the tipping point for change within these networks and from there for how they are regulated.

6.3. Adaptability of regulation

90. Both the building blocks IM's and the rules contained in part 4 that sit behind the IM's do not easily lend themselves to being adaptable and flexible. Regardless of the form of regulation - be it one size fits all or not, it seems clear that at a minimum some form of flexibility is needed so that the regulatory mechanisms can accommodate change in the regulated networks environment. On this basis there appears to be a case to amend the IM's to achieve this objective.

91. The second point we would make here is that if we accept that at some stage technical change and demand side changes will eventually manifest themselves

in a material way then it is important that the IM's, network pricing and retail service arrangements including prices are aligned so that these changes are realised in an efficient manner. To us this suggests that the current gaps regarding the efficiency of the EDB structure and the lack of understanding about the productivity of the distribution system need to be overcome sooner rather than later.

92. This is where the trade off for the Commission comes into sharp focus - there remains a desire for short term IM stability and for performance improvements within the regulated businesses, but there will be the need to have to make substantial changes to Part 4 (possibly quickly) so that the IM's can be adapted because competitive options become available. This is a problem for all participants in the regulated energy system.

6.4. Incentives for a CPP

93. The Commission has framed the key issue for this topic as whether the Commission’s choice of method for setting the value of key parameters affects the incentives on suppliers to seek a CPP. The Commission has focused on the difference in value for the WACC under the DPP and CPP (due to movements in the risk free rate). However it is not clear to us why the difference in parameters would be the binding constraint preventing suppliers from applying for a CPP. (The apparent effort required to prepare a CPP proposal, lack of certainty about the outcome and the conditions imposed on suppliers once an application is lodged may also discourage supplier applications).

94. The discussion of the problem in the Commission’s problem definition paper seems to mix the question of what the Commission uses as an estimate of a fair cost of capital over the regulatory period with how suppliers actually manage their debt funding for a funding period that is likely to be considerably longer than the regulatory period. A starting point for the analysis would be a comparison of the WACC estimated by the Commission with the actual funding costs and maturity structure of supplier funding (to the extent that this can be identified separately for the regulated asset base and other business assets held by suppliers).

95. In general we have almost no evidence on which to assess the materiality of this issue. We do not have examples from suppliers of possible CPP proposals that could have provided benefits to consumers sooner but were not advanced because the input methodology prevented the Commission and supplier from reaching agreement on how the gains would be shared between consumers and the supplier over the next regulatory period. Provision and discussion of these examples would be helpful in assessing the materiality of this issue.

96. We suggest that the real issue here is how the regulatory cycle affects the timing of supplier decisions on innovation in service provision and investment in regulated versus non-regulated assets.

7. What next?

97. Throughout this report we have proposed specific matters to consider either when evaluating potential problems or when thinking about solutions.

98. Our suggestions regarding the potential for problems from system changes need further scoping, more evidencing and the various impacts on and from the IM's need assessing. This process will enable decisions to be made on what approach to take for developing a strategic path to deliver on the agreed outcomes.

99. We are however not sure about specific answers simply because there is no readily observable example of competing electricity networks against which to assess whether the pathways and solutions that we suggest are desirable, efficient and to the long term benefit of consumers.

100. Possible ways forward could include some or all of the following:

Results based regulation

101. For example, we may find that the greater use of performance based regulation can improve the efficiency of the distribution system and the quality of supplier investments – including in the transmission network. As we will argue below the near term future will likely see the impacts of the disruptions we described earlier. There are varying views about the timing of when the impacts will be felt but the consensus is that they will be well visible before 2023.

102. At a minimum we expect that outcomes from the current IM's should be evaluated to identify whether they are indeed the sorts of outcomes that could expected from a competitive and efficient regulated energy sector.

103. We question whether they are. We also question whether accepting them as they are is otherwise good enough. We need to know whether these outcomes are good, bad or in-between. As a suggestion, it would be most useful if we were to develop a scenario that describes what a competitive and efficient energy sector looked like and how it performed so that we have a reference case to refer to throughout the IM review.

104. In this regard the following suggestions could contribute to thinking about where to turn if our take that changes are needed to the IM's, is correct.

- Use of reference models for network performance
- UK experience as a reference
- use of CPP as a tool for dealing with uncertainty and to overcome issues with EDB's starting in different places and having different development trajectories.

EDB rationalisation

105. The distribution system appears to us to be inefficient and is likely costing consumers dearly. If this is true, then the inefficiencies will get worse as these changes flatten load curves and render current asset management plans

redundant. There could be large scale spare capacity in the distribution networks and in the transmission grid.

106. Thinking about the distribution 'system' further – we observe that electricity distribution around New Zealand is handled by 29 EDBs some of whom are small and owned by community trusts. These entities all have governance and management structures that consume resources and create costs which are passed through to consumers. We have little understanding at this time as to whether these costs and inefficiencies are necessary or whether there are better alternatives to the management of energy distribution. We propose there is a need to find out and find out soon.

107. We could then imagine a process whereby international standards for competitive energy distribution networks could be benchmarked to establish an efficient baseline performance level for regulated assets and productivity. This could be overlaid with the likely consequences from the disruptions we discuss above and appropriate adjustments made to accommodate their impacts. Defining an efficient distribution network would provide a baseline revenue cap for the wider network that would then be allocated across whatever networks are required to manage energy distribution regionally. The current IMs would not fit well with this type of thinking.

108. An interpretation off the objectives for Part 4 suggests to us that consumers should only pay the costs that an efficient electricity distribution industry would charge. This 'notionally efficient' distributor should be the benchmark against which the current structure is measured. Currently each distributor is assessed individually. One option is to use the notionally efficient distributor as the overall revenue/price cap. The use of a notionally efficient supplier as a benchmark is a standard benchmarking method used by international regulators.

109. There is obviously further work required to evidence the materiality of the problems and issues we suggest in this report - addressing the questions that we pose will assist in determining whether it is worth putting in the time and effort to look into possible welfare enhancing solutions.

Appendix A Batteries

110. We earlier described the combination of solar PV and electricity storage batteries as possibly being the tipping point for material changes in the energy system. It is clear that the use of storage will not be limited to households or to the distribution network but will impact the whole system. The potential for battery technology to make a material impact is emerging overseas.

Household PV and batteries

111. The disruptive potential of solar PV is now real in a number of countries (for example Queensland where the equivalent capacity of one and a half Clyde dams has been added through household PV systems in a very short time).The electricity sector represents a fascinating example of the potential for ongoing widespread disruption as PV costs fall, even though solar scale overall remains relatively small.

112. While solar accounts for only less than half a percent of electricity generation in the US, the business model for US utilities depends not so much on the current generation base as on installations of new capacity. Solar could seriously threaten the latter because its growth undermines the utilities' ability to count on capturing all new demand, which historically has fuelled a large share of annual revenue growth. (Price increases have accounted for the rest.)

113. Although it varies by market, new solar installations could now account for up to half of new consumption (in the first ten months of 2013, more than 20 percent of new US installed capacity was solar). By altering the demand side of the equation, solar directly affects the amount of new capital that electricity utilities can deploy at the regulated return on their RAB.

114. These disruptive changes have become influential in the US, to the point that Brattle Group has changed their approach to modelling electricity grids systems[6]. Previously they modelled the grids separately and independently from the wholesale market however they recently moved to modelling the whole system in a more dynamic way to accommodate the broader influences of these disruptions. We believe that this is an essential way forward if the impacts of grid changes on consumers are to be understood and the future energy system adequately regulated.

115. We also understand the FERC is now considering a proposal that a system operator could soon be needed in a number of local US distribution networks to link the supply and off-take of electricity across those networks. One of the concerns is that in certain places they can see the growth of local generation heading towards the 40% point and are concerned that this level is above the threshold at which grid control could be lost.

116. This is a real time problem for wholesale markets, for systems operations and for regulators. Issues have emerged in both Hawaii and California where significant solar PV and wind generation capacity now exists - as at end 2013

[6] Brattle made reference to their re-engineering of the network models because of this emerging situation late in 2014 at a symposium on the changes that these disruptions were forcing already.

there were 170,000 distributed PV systems connected to the California distribution grids. All the larger installations are monitored by the systems operator but the smaller ones - around 90% of PV capacity are not monitored and generate into the grid as wind and sun allow. The California system is now facing over-generation during the day and is looking to introduce heavy curtailment measures to limit system disruptions. In steps grid scale batteries!

Grid scale battery storage

117. In the grid scale battery world, a US company - Eos, is now selling its Aurora 1000|4000, a containerized 1MW/4MWh DC battery system, which will support renewable energy integration, peak demand reduction, and lowering of customer electricity bills. At a price of $160/kWh, demand for the Aurora product has surged since Eos launched the commercial offering in January 2015. Qualified pre-orders now exceed 3,000 MWh and are growing rapidly, with deliveries beginning next year.[7]

118. Until now, large costs and limited manufacturing capacity of batteries for large-scale electrical storage have kept US utilities from committing to the technology. However a Texas electric distribution utility is now stepping out with a plan to spend up to $5.2 billion on batteries to back up its transmission and distribution grid and reduce power fluctuation from renewable power sources. In a study it performed to justify the plan, Oncor Electric Delivery claims the move would lower consumer electric bills and preclude costly construction of new power plants.

119. But there is an interesting regulatory catch: In Texas, distribution utilities such as Oncor now are prohibited from owning power plants, and state lawmakers, who deregulated the industry 12 years ago, would have to amend a law defining batteries as a power producer. Oncor officials are pushing for legislation to be introduced for the change, but opposition is already brewing from power producers, including sister companies of Oncor.[8]

120. Oncor executives have said in published reports they expect battery prices to be competitive for their plan by 2018. Oncor is looking to have batteries installed across the entire state-wide grid, not only in its own service area. The state's grid has a capacity of about 81,000 MW.

121. A Brattle report on the proposal claims the batteries must be installed across the entire grid. "Considering both the impact on electricity bills and improved reliability of grid-integrated storage, customer benefits would significantly exceed costs," says Judy Chang, the Brattle lead author of the study.[9]

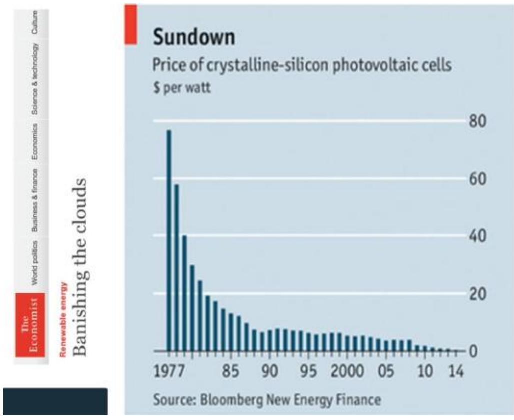
122.

7 Eos Energy Storage Raises $23 Million to Support Manufacturing of Grid-Scale Batteries and Fulfilment of 3,000 MWh of Qualified Pre-Orders. Business Wire, May 2015.

8 Batteries for Managing the Grid ASME article December 2014.

9 http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708

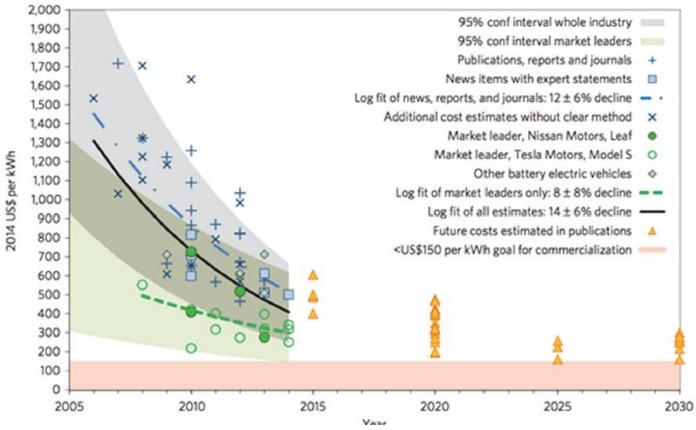
Figure 6 PV cells - market prices per watt



Source: Smart Grid Forum July 2015

123. PV cells costs have fallen to be around US30c per watt, though this is not a universal price - the EU have applied anti-dumping restrictions on cells from China and Asia which is holding the European prices up. Despite this the expectation is that, within the next few years, PV will achieve parity with grid generation on a widespread basis which, when combined with cheap batteries (figure 4 below) will change how consumer interact with the traditional grids. Here battery costs in 2014 are ahead of most estimates of where costs would be in 2020.

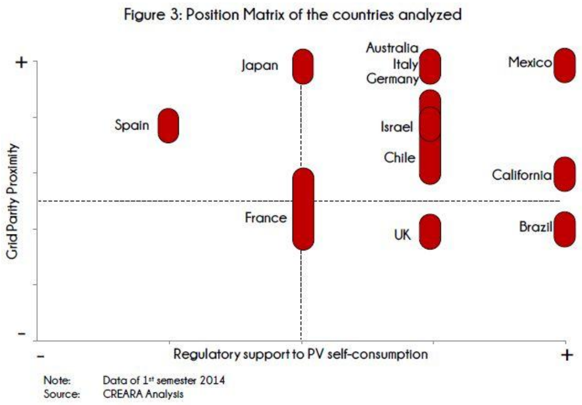
Figure 7 Battery costs electric vehicles



Source: Smart Grid Forum July 2015

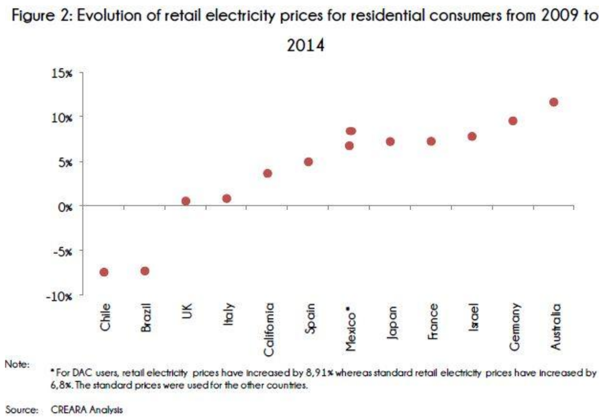
124. The PV cost cross-over has already taken place in some countries. From a grid parity monitor of PV costs and retail electricity prices in a number of countries by CREARA, grid parity in a number of countries is reported, as follows:

Figure 8 Grid parity - residential PV costs



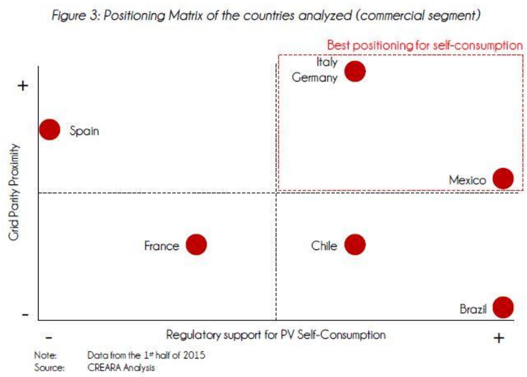
125. Interestingly many of these countries have faced retail price increases for traditional grid supplied energy (figure 6 below) but not to the extent that we have here in New Zealand.

Figure 9 Retail price changes - countries with high PV take-up



126. The situation is similar in the commercial sector of a similar survey of countries.

Figure 10 Grid parity - commercial PV costs



127. The take out here for us is that the economics are definitely moving quickly towards grid parity in many countries as costs of PV cells and installation costs fall steeply.

Appendix B Detailed questions

128. In light of these uncertainties and to make progress with the IM review we propose that various lines of enquiry should be made - that is, a series of questions need consideration to identify both whether there are going to be problems with the IMs and whether/what sort of changes are needed.

129. We set out these questions and our initial thoughts/answers as follows:

Q1: How could networks reconfigure their assets, business models and pricing over time as this future unfolds.

130. The first step in the process is to objectively assess whether the IM building block process serves consumers and regulated businesses currently. The divergent views we observed at the IM forum suggests to us that some EDB's are looking for changes to the IM's regardless of technology and demand side changes.

131. We would also observe that EDB's are at different starting points regarding these changes and uncertainties:

- Cost recovery is different across consumers and across EDB's - charges to retailers, 'pass through' charges, and final prices to consumers are not consistent.
- Different exposure to business sectors - gas, electricity and other sectors that are not energy related.
- Various levels of participation in new technologies - some EDB's are embracing technology changes already while other do not want to be involved
- EDB's are absent a direct consumer relationship - it is indirect which makes it hard to identify whether and how they contribute to improvements in consumer welfare. What is their role?

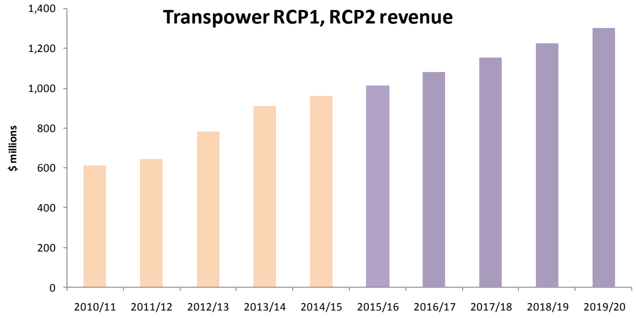
132. We expect different pathways forward for different EDB's and likely a different one overall for Transpower. The efficient supplier in the future will be less likely one who installs transformers of the right capacity but rather one who chooses alternative solutions to network issues at least cost. The IM's need to incentivise EDB's to look for lower cost supply side solutions, regardless of whether these involve more complex technologies (such as grid scale batteries).

Economics of electricity system in NZ are changing

133. Network costs have been, and will in the foreseeable future be, on the rise. The RCP2 revenue and price paths for Transpower and the EDB's have ongoing cost

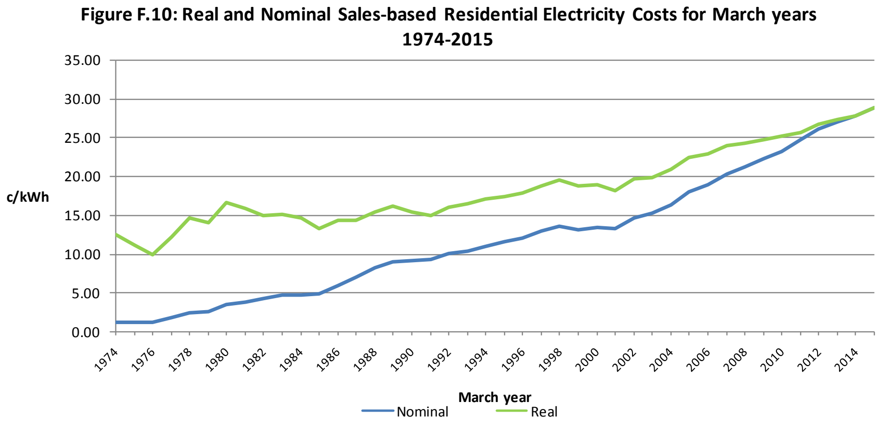
increases for consumers. For instance Transpower regulated revenues look like this :

Figure 11 Transpower revenues under regulation



Source: NZIER analysis of RCP2 data

Figure 12 Retail residential electricity prices



Source: NZIER analysis of MBIE data

134. On the other hand costs for alternatives to network supplied energy are travelling in the opposite direction - for us the role of the IM's in this situation need to be considered carefully to make sure that the building block approach to the IM's does not stifle innovations and institutionalise guaranteed revenue increases for regulated businesses.

Q2: how to think about network cost recovery amid these changing economics and changing asset risk profiles.

135. This is a more immediate issue. Does the building block approach lend itself to easy change in the short term - some EDB's will be ahead of others and likely need a different approach to their regulation. This is also where boundary issues will manifest themselves between the allocation of costs associated with regulated assets and those non-regulated parts of their businesses. Transparency of how the EDB's go about allocation of capital and operating costs between these two areas will be especially important as it is one of the foundations for how the IM's will need to be modified or not.

136. There are also a number of other questions that need attention when considering this issue - will we need to adapt the existing IM cost recovery model; and if yes do we adapt what we have, or develop a new regulatory structure for the longer term.

137. This is a balancing act in some ways - changing part 4 of the Commerce Act to adjust or add to the IM's is a material undertaking that will exacerbate the stability of economic regulation in the energy sector. On the other hand these changes to demand side and technology provide the opportunity to drive productivity improvements in the sector to the benefit of consumers. The Commission will need to carefully weigh up the trade-off here.

Overall efficiency of electricity system is not known

138. The purpose of the IMs in the current electricity system is to provide a framework for estimating the pricing, quality of service and revenue outcomes for monopoly networks (Transpower and EDB's) that would be delivered if these businesses operated in a competitive market rather than as monopolies.

139. To make this examination tractable and reduce compliance cost, the Commission seems to have reframed the question about "competitive market outcomes" as an assessment of whether the operational expenditure and investment plans of each regulated business reflects the average prices and aggregate levels of expenditure that would occur if Transpower and the EDB's were constrained by competitive pressure.

140. However, using the expenditure and investment plans of each business as the starting point for the assessment tends to tacitly accept continuation of the current potentially inefficient structure (i.e.: 29 electricity distributors) including past pricing and investment practices and it biases the scope of the assessment to consider what the regulated business expects to happen. It does not encourage examination of the following issues:

- whether the level and method of charging different groups of consumers for the lines company service is efficient, i.e. do they recover the cost of the service provided?
- linking revenues and prices to services actually required by and delivered to customers
- the development of competitive markets for the provision core service delivered by networks (i.e. capacity)
- consumer willingness to pay for their chosen service levels

- how the cost impacts of changes in the use of network assets should be allocated across consumers
- how EDB investment decisions alter their business models, expand unregulated revenue streams which impacts the use of the regulated assets.

141. The distribution system appears to us to be inefficient and is likely costing consumers dearly. If this is so the inefficiencies will get worse as these disruptive technologies flatten load curves and render current asset management plans redundant. There could be large scale spare capacity in the EDB networks and also in the transmission network. As mentioned we believe that these changes will also provide opportunities for productivity improvements in regulated businesses by offering a counterfactual to the present situation.

142. Thinking about the distribution 'system' further – electricity distribution around New Zealand is handled by 29 EDBs including a number of community trusts. These entities all have governance and management structures that consume resources and create costs that are passed through to consumers. We have little understanding at this time as to whether these costs are necessary or whether there are better alternatives to the management of energy distribution.

Q3: regarding EDB's how well does the building block model fit now, what incentives does the model currently provide for an efficient energy sector and the take-up of technology and new services. How do EDB's demonstrate they deliver consumer benefits.

143. These are big issues that need some form of answer or, if answers cannot be found, at a minimum we need a way of identifying whether there is a need to adapt or change the existing IM's to drive productivity and a more efficient distribution sector.

Energy system demonstrates need to be actively managed

144. Changing industry circumstances have revealed that the system needs to be more actively managed - parts are structured differently (nodal market, regulated networks, 'competitive' retail market) but the intersections appear unstructured and not actively managed. This is likely a problem with regulatory governance and the application of economic regulation. We discussed this issue in some detail in our March memo to MEUG, including our analysis of the adequacy of the intersections between the parts of the existing system.

Q4: because the monopoly status of networks may start to change quite soon and pressure both network businesses and the regulator, will some parts need a strategy to exit regulation or for a different type of regulation.

145. This is a policy issue that needs to be considered in parallel to the IM review

Q5: are regulators already pressured and constrained by narrow objectives, prescribed forms of control and widely varying pricing approaches.

146. Likely yes - we would point to the difficulties with transmission pricing over many years that is still not resolved. For us an important aspect of that process has been the inability to adequately consider what impacts both the current pricing and the proposed changes to transmission pricing will have on the consumer side of the GXP. This important issue will be amplified with the review of the distribution pricing.

Economic signals (prices) do not reflect efficient costs

147. Electricity transmission and distribution pricing has recently come under the spotlight - where both the level of charges and the structure of pricing appears to be not cost reflective. There are likely efficiencies and improved outcomes that can be generated from changes here. This is however a somewhat speculative statement because we do not know how much of a problem this could be but for us we need to find out so that the reviews of both the IM's and the network pricing methodologies that are in process can provide outcomes that deliver efficient prices for consumers.

148. Changing industry circumstances will impact this issue further ... we are not entirely clear what will unfold and therefore what impacts the future will have on today's costs.

Q6: What is missing from the Commission views regarding topics for review

149. Not a lot is said about the efficiency of the regulated networks and businesses - as is discussed in several places in this report we do not have a good sense as to where the EDB's and Transpower are in this regard.

150. Not a lot is said about the choice of regulatory mechanisms (other than form of control) - given where we are with the development of the IM's under part 4, the future outlook and the use of other regulatory mechanisms internationally, should we continue to use cost plus building block IM's.

151. Also not a lot is said about whether consumers are being delivered long term welfare improvements from the system as it operates under the IM's. We have described our concerns here earlier.