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Miriam R Dean CNZM QC
Chair
Electricity Price Review
Secretariat, Ministry of Business, Innovation and Employment
15 Stout Street
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By email: energymarkets@mbie.govt.nz

Dear Madame Chair and fellow Panel Members

RE: Electricity Price Review Hikohiko Te Uira First Report for discussion

The Independent Electricity Generators Association Incorporated (IEGA) welcomes the opportunity to make this submission on the first report of the Electricity Price Review (EPR Report).[1]

IEGA commend the government for establishing this review and the work the panel has undertaken to date. We support the focus on fairness, affordability and competitiveness and agree it is timely to ensure the regulatory regime is fit-for-purpose when there are significant opportunities for renewable electricity to underpin New Zealand's transition to a low emissions economy.

The IEGA suggest there are changes that can be made to current arrangements to ensure the electricity sector is efficient and offering fair prices today while still ensuring sufficient investment for tomorrow's consumer – and simultaneously adapting to environmental and technological changes.

Background on the IEGA

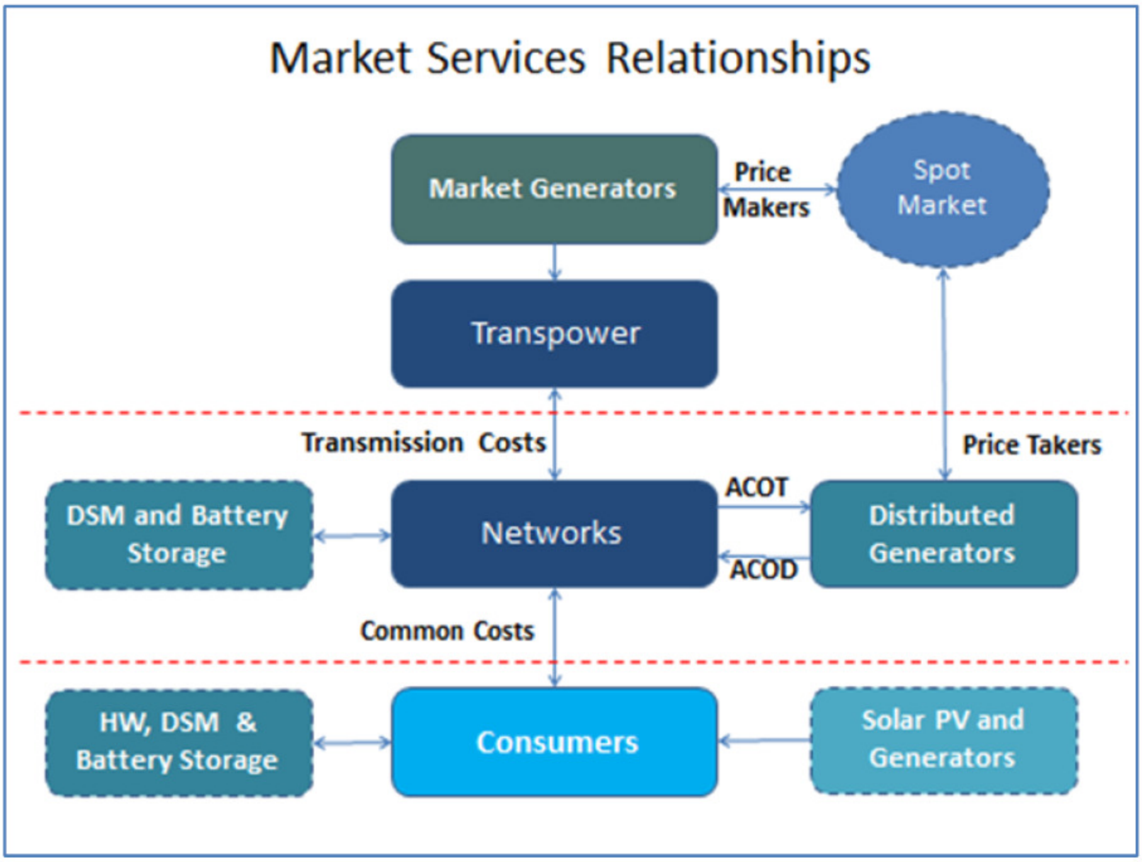
The IEGA comprises approximately 30 members who are either directly or indirectly associated with predominately small scale power schemes throughout New Zealand for the purpose of commercial electricity production.

[1] The Steering Committee has signed off this submission on behalf of members

Our members have made significant economic investments in generation plant throughout New Zealand that is embedded within local distribution networks. Our members are proud to contribute to achievement of New Zealand's 90% renewable electricity target with 95% of our electricity generated from renewable fuel compared with ~83% for the entire sector[2]. Combining the capacity of member's plant makes the IEGA the sixth largest generator in New Zealand and the combined portfolio benefits of this group to the energy market are material.

IEGA members are small, entrepreneurial businesses, essentially the SME's of the electricity generation sector, providing significant benefits to the regions in which we operate. Members are mostly not vertically integrated with retail. IEGA members' that do not bid their generation output into the wholesale spot market are therefore price-takers. This investment has to be as efficient as utility owned investment in order to be able to make an appropriate rate of return.

IEGA members own distributed generating plants that export electricity in to their local network and for the most part do not utilise transmission services but effectively compete with transmission services to deliver electricity to end users. The services provided by our sector assets differ from market generators and from consumer-owned DG predominately for own use, and the regulatory approach should be commensurately different. The following diagram demonstrates the relationship of distributed generation to other participants.



[2] Source: http://www.emi.ea.govt.nz/Datasets/Wholesale/Generation/Generation_fleet/Existing

Distributed generation in New Zealand

We note there is limited commentary in the EPR Report about small commercial scale independently owned distributed generation. The focus of the report is more on distributed generation behind a meter (which can be consumer owned distributed generation, such as solar pv, or cogeneration on industrial sites) as well as focusing on new or emerging technologies.

The benefits of distributed generation are it:

- provides 10% of New Zealand electricity by output (including utility-owned distributed generation) which is equivalent to over twice the output of the Huntly power station
- introduces competition resulting in lower regional electricity prices for consumers as well as enabling new retailers to enter the market with Power Purchase Agreements
- employs around 500 people across most regions of New Zealand
- results in rebates and distributions back to local communities. For example, Pioneer Energy has distributed approximately $75m over 15 years to its community trust shareholder
- assists with security of supply. Many of IEGA members' distributed generation plant supplied their local regional networks prior to the grid being built so have a proven track record of reliable supply as they are designed to run islanded from the grid in an emergency loss of transmission. Recently one of our member's distributed generation plant provided emergency power to Grafton hospital when Vector lost power
- avoids or defers distribution network and transmission investment
- is complementary to consumer load management, These network connected services have been incentivised to flatten more than 20% of the New Zealand electricity system's peak demand.

As well as contributing to New Zealand's renewable energy target, distributed generation also improves New Zealand's energy productivity. Energy productivity includes the cost of producing and delivering electricity. Distributed generation can be built at an LRMC equivalent to grid connected generation. Distributed generation is usually located closer to electricity users than grid connected generation and uses only the local network to deliver electricity to users. Grid connected generation (by definition) uses the transmission grid and the local network to deliver electricity. Transporting electricity results in lost energy (due to resistance). Recent data shows 1,239GWhs (3.2% of total electricity injected) was lost while travelling over the transmission grid; 1,670GWh (6%) was lost while travelling over distribution networks.[3] This is equivalent to the output of the Huntly power station.

New Zealand's energy future

Our members are innovative, entrepreneurial and passionate about New Zealand's renewable advantage and potential. They have a portfolio of new economic renewable generation projects consented or under investigation which can meet growth in local demand.

[3] Top Energy took into account the economic value of lost energy (~6% in their case) when deciding to invest in distributed generation compared with investing in 110kV lines. Top Energy application for an exemption http://www.ea.govt.nz/dmsdocument/21586

However, decisions about when to invest depend on stable and predictable regulatory environment. Regulatory change should build on, and not disrupt, New Zealand's existing low emission activities, such as IEGA members' investment in renewable distributed generation.

This is an exciting time for the energy sector, and potentially our members. For example, demand for renewable electricity can be expected to increase above historic BAU growth rates with an uptake of electric vehicles; the supply of electricity will become more diverse as consumers decide to invest in solar pv and / or battery storage; distributed generation, or distributed energy resources, may become the norm with investment in physical transmission and distribution network infrastructure becoming the 'alternative'.

In summary, our key messages are:

- Distributed generation is already playing an important role in NZ's renewable electricity system in competition with transmission and distribution infrastructure and providing numerous local benefits.
- We acknowledge that the EPR is not about how New Zealand can achieve its climate change obligations. However, any changes as a result of this EPR should not undermine or undo New Zealand's progress to a higher contribution from renewable energy. For example, a change that makes smaller scale commercial renewable DG uneconomic.
- There is a need for considerable capacity investment in the medium term. IEGA members have options for new generating capacity connected to local networks that are economic, have a smaller environmental footprint than grid-connected generation and provide an incremental increase in supply more aligned to growth in demand.
  The IEGA suggests the EPR Panel should commission a study to evaluate the public's preferences in relation to the scale of future renewable power schemes. This could identify the social cost of utility scale versus incremental smaller regional generation capacity and assist with identifying and addressing barriers to new generation investment.
- The IEGA's experience is that there are numerous barriers for new commercial scale independently owned DG (between 1MW and 30MW), namely:
  - costs imposed by government agencies: the cost of consenting or re-consenting a renewable generating plant is ~$0,5 million; concessions to access to Department of Conservation resources; ongoing monitoring and compliance
  - Electricity Authority rules and 'market' related costs: complicated rules that are designed by and for utility scale gentailers which are becoming more complex as the Authority plans to impose a 'market' framework on emerging technologies and 'consumer engagement'
  - financing is difficult given the above barriers and regulatory change. Debt funding is more limited for independent 'SME' investors.

  These costs and barriers are disproportionate to the scale of investment in our smaller commercial DG.

- IEGA's suggestions for improvements are:
  - the NPSREG should be reviewed to improve its effectiveness for consenting new or re-consenting existing renewable generation plant
  - the government consider a less complicated regulatory regime for the 'SME' sector of the generation market. This approach is taken by government for SMEs in other sectors of the economy. IEGA notes that the Electricity Industry Participation Code has a de-minimus of 10MW in relation to obligations to the System Operator – this could be extended to apply in other areas.
  - the EPR Panel investigate a de-minimus threshold for small commercial DG less than 10MW (but not connected behind a consumer's meter). This de-minimus of <10MW should be included as a starting point in key policy, terms and conditions and rules.

Attached as Appendix 1 is the IEGA's response to questions raised in the EPR Report that are relevant to the activities of IEGA members. The report and questions appears to refer to 'consumer' in the context of the end-user of electricity. IEGA has interpreted this more broadly – for example, owners of distributed generation are consumers of distribution services. This interpretation is consistent with the Commerce Commission's approach.

Appendix 2 includes two case studies: a case study of a member's re-consenting experience – over 19 years at a cost of over $0.5 million to re-consent a ~1MW hydro generation power plant; a case study of development and consenting of a new hydro with a changing regulatory environment.

The IEGA would welcome the opportunity to discuss this submission with you in more detail.

Yours sincerely

David Inch
Secretary

Enclosed:

Appendix 1: IEGA response to questions

Appendix 2: Case Study – Re-consenting Raetihi hydro generation power station, 19 year process at a cost of over $0.5 million

Appendix 1: IEGA response to questions

Part three: Consumers and prices

Consumer interests

1 What are your views on this assessment of consumers' priorities?

The IEGA agrees with the EPR description of consumers' priorities. IEGA's members' renewable distributed generation (DG) is embedded in the local network and is part of the local community. Some plant are owned by the community. There are numerous investment opportunities for small commercial renewable DG given a stable and predictable regulatory environment. The scale of this investment means it is closely matched to progressive growth in electricity demand.

Environmental concerns as well as some sense of control over investment outcomes appear to be a high priority for consumers – and renewable DG investment addresses these concerns.

Growth in distributed generation, or distributed energy resources, is a major focus overseas. These distributed systems involve local communities and consumer investment and predominately use renewable fuel.

It would be interesting to understand consumers' perceptions of the 'social licence' to operate for small commercial scale DG relative to utility scale generation plant. We suggest the EPR Panel or MBIE commission a study to evaluate the public's preferences in relation to the scale of future renewable power schemes. This could identify the social cost of utility scale versus incremental smaller regional generation capacity and assist with identifying and addressing barriers to new generation investment.

3 What are your views on whether consumers trust the electricity sector to look after their interests?

Given the nature of IEGA members' investment, being embedded in the local community, the trust of local consumers is a critical part of their ongoing licence to operate. IEGA members take this very seriously.

The 'electricity sector' is wide ranging and covers all participants, including regulators. The IEGA also considers our members to be consumers in this sector. The IEGA suggests trust is encouraged by a robust and stable regulatory environment.

DG investors face a regulatory environment that might only become more stable in about five years when changes to the TPM and distribution pricing are in place. The level of uncertainty is disproportionate to the size of this sector and the scale of the businesses owned by IEGA members. This uncertainty is impacting the bankability of existing and new DG investments.

Prices

4. What are your views on this assessment of the make-up of recent price changes?

The IEGA members are price takers for their generation output. They do not have the financial or physical resources to man a 24/7 desk bidding into the wholesale spot market.

We have concerns about the dominance of vertically integrated gentailers on outcomes in the wholesale spot market and the hedge market – these concerns are detailed in our answer to question 17 below.

6 What are your views on the outlook for electricity prices?

The EPR Report states in the Introduction (page 7):

> Another new element of this review is the transition to a low emissions future. Achieving net zero emissions will require far reaching changes to the way New Zealand meets its energy needs, including a substantial expansion of renewable electricity to reduce dependence on fossil fuels for transport and industrial energy needs. This work is for the Interim Climate Change Commission, not us, but we have been mindful of the impact of climate change on the sector, particularly electricity pricing.[2]

The IEGA suggests that any change to regulation of the electricity sector as a result of this review has to be consistent with the government's overall climate change objectives. For example, a change recommended by this review that resulted in a lower contribution from renewable fuel might be consistent with the Terms of Reference for this review (ie improve affordability) but would be devastating for achievement of New Zealand's international climate change commitments.

Any reduction in distributed renewable generation capacity will increase emissions and wholesale prices, whether by this capacity being replaced with thermal capacity and/or due to the increased level of transmission and distribution losses that occur when electricity is generated far from load. If distributed generation no longer supplies electricity during periods of peak demand we estimate the value of the lost electricity (as demand is met instead by grid connected generating plant located distant from load) could be $500 million per annum.

IEGA agrees that electricity price structures must include a peak demand signal – this will influence demand for electricity as well as generation output and investment.

The IEGA notes that the EPR report states "*we examined fairness in terms of the average prices paid by consumers and also how common costs are shared among consumers*".[4] We discuss the issue of allocating common costs in answer to question 22 below on the allocation of distribution costs.

[4] Page 12

Affordability

7 What are your views on this assessment of the size of the affordability problem?

IEGA acknowledges that affordability of an essential service like electricity is an important consideration for the government. However, the outcomes from the focus of the EPR on affordability must also be consistent with the government's other priorities such as their overall climate change objectives.

Summary of feedback on Part three

10 Please summarise your key points on Part three.

As requested the summary of IEGA's key points on Part three are below. This is a summary and to fully understand this summary it is important to read the substantive answers to questions on Part three above.

Consumers' priorities: Environmental concerns as well as some sense of control over investment outcomes appear to be a high priority for consumers – and renewable DG investment addresses these concerns.

Trust: In our view, the IEGA is a 'consumer' in the electricity sector – we consume services of distribution companies and the regulators. Trust in the regulators of the electricity industry is engendered by a robust, transparent and stable regulatory environment, especially when investors are making decisions about long life assets.

Recent price changes: IEGA's members are price takers for their generation output. Concerns about the dominance of vertically integrated gentailers on outcomes in the wholesale and hedge markets are detailed in answer to question 17 (Part 4).

Outlook for prices: The government will have to weigh up if the EPR outcomes as a result of a focus on affordability have an impact on other government priorities, such as international commitments to action on climate change.

Solutions to issues and concerns raised in Part three

11 Please briefly describe any potential solutions to the issues and concerns raised in Part three.

Consumer priorities: It would be interesting to understand consumers' perceptions of the 'social licence' to operate for small commercial scale DG relative to utility scale generation plant. We suggest the EPR Panel or MBIE commission a study to evaluate the public's preferences in relation to the scale of future renewable power schemes. This information could help shape policy responses to current challenges of achieving climate change and renewable energy targets as well as accommodating new technologies and business models and assist with identifying and addressing barriers to new generation investment.

Trust: IEGA suggests that trust in the regulators of the electricity industry is engendered by a robust, transparent and stable regulatory environment, especially when investors are making decisions about long life assets.

Part four: Industry

Generation

12 What are your views on this assessment of generation sector performance?

IEGA members' that do not bid their generation output into the wholesale spot market are therefore price-takers. Their investment in generating plant is therefore as efficient as utility owned investment in order to be able to make an appropriate rate of return.

The IEGA agrees with the EPR Panels concerns about short-term market power and that this should be investigated.

13 What are your views on this assessment of barriers to competition in the generation sector?

IEGA agrees that the limited depth of the contract market is one of the factors inhibiting expansion or new investment. It is difficult to negotiate with vertically integrated gentailers that make up ~90% of the generation and retail market and who 'control' the hedge market. This is discussed in more detail in answer to question 17 on vertical integration.

However, there are a number of other barriers – which we have grouped under government environmental obligations; generation market obligations; and the consequent impact on financing.

Government environmental obligations

The timeframes and processes associated with government environmental obligations for renewable small commercial generation plant are lengthy and expensive.

Consenting, or re-consenting, hydroelectricity generation operations can be a disproportionate cost on the business compared with utility scale generators. We enclose two case studies in Appendix 2. In summary:

- re-consenting the Raetihi hydro plant took 19 years and cost over $0.5 million (excluding the owner's time)
- the decision to invest and fund a new hydro generating plant was made on the basis on a regulatory regime that appeared stable and assisted with funding. By the time all statutory requirements were met and the plant commissioned 5 years later the regulatory regime managed by the Authority changed having a significant impact on the financial viability of the plant.

IEGA supports a review of the National Policy Statement for Renewable Electricity Generation (NPSREG). IEGA members can provide numerous examples of how the Resource Management Act constrains investment in renewable generation. Further the NPSREG does not provide clear direction. The NPSREG must be more prominent and taken more seriously by decision makers.

Our concerns include:

- the NPSREG has equal weighting with numerous other criteria in the RMA so has no 'teeth'
- there is little consistency between regions / districts as to the provisions that apply to the operation, maintenance and development of renewable electricity generation activities
- the provisions in the NPSREG are not as directive or 'forceful' as those within the New Zealand Coastal Policy Statement ('NZCPS') or the National Policy Statement on Electricity Transmission ('NPSET') which impacts on its implementation within lower-order statutory planning documents
- the NPSREG has not provided any certainty for the re-consenting of existing renewable electricity generation schemes.

We would welcome the opportunity to participate in a thorough and wide ranging review of this policy instrument given the significant need for new renewable generating capacity if NZ is to transition to a low emissions economy.

In addition, members' have limited resource to monitor and engage in local council initiatives to amend or develop regional plans. More guidance from government and a more consistent approach to consenting water take and use across local councils can be expected to reduce this cost of doing business.

Other obligations include:

- access to Department of Conservation resources. It appears there is no standard methodology for applying fees for this access
- different approaches across councils to ongoing monitoring and testing which increase costs if members' have plant located in different areas of New Zealand. For example, different councils apply different rules for the passage of the same fish past power stations in different catchments.

Participating in other government policy initiatives impacting electricity is also complex, time consuming and we risk missing important changes if attention wains. Current examples are freshwater allocation and pricing, policy changes to achieve renewable energy and climate change targets. One member is now spending 50% of his time on regulatory factors – up from about 10% when he started in business.

Generation market obligations

We refer here to obligations managed by the Electricity Authority and System Operator. The IEGA has no concerns about the approach or rules / obligations managed by the System Operator. In particular, the fact the System Operator does not require generation below 10MW to be dispatched is significant. The cost of 24/7 participation for IEGA members would be prohibitive.

However, we are concerned about:

a) issues relating to negotiating with monopoly distribution companies
b) issues for new DG negotiating with Transpower
c) engagement with the Electricity Authority
d) All of these barriers or concerns culminate in it being difficult for independent small commercial investors to debt fund new generation projects.

a) Issues relating to negotiating with monopoly distribution companies

Part 6 of the Electricity Industry Code stipulates timeframes in relation to connection agreements but these are not adhered to. The DG owner could take a dispute to the Electricity Authority but this is with the party you are trying to connecting to and creating a long term relationship with.

Also under Part 6 connection charges are limited to incremental costs but the distribution company determines how much is new to enable connection for DG and how much is something that the distribution company wants for its network (eg. communications systems).

There are examples of distribution companies preferring distribution solutions without discussing if the DG could make a lower cost investment that achieves the same outcome. This can also impact the charges made to DG.

Also distribution companies view DG as only a cost when DG can and does provide services to distribution companies which they are not being paid for.

b) issues for new DG negotiating with Transpower

IEGA believes it is bizarre that new DG has to negotiate with Transpower for avoided cost of transmission payments when Transpower is a competitor to DG.

A member described this as a farmer with two cows trying to negotiate with Fonterra.

Transpower is required by the Commission's regulatory regime to consider transmission alternatives but has never signed a Grid Support Agreement with a transmission alternative. Further, Transpower has no funding for this arrangement (or their demand response programme beyond 31 March 2020).

DG provides an incremental no-regrets increase in electricity volumes which represents an option value compared with lumpy transmission investment during this uncertain time. It is unclear if Transpower can value this 'option'.

c) engagement with the Electricity Authority

Members have found the Authority incredibly slow to investigate breaches of the Code (eg, a complaint laid in 2013 is still awaiting resolution).

The Authority's real-time pricing proposal is confusing. It proposed 'dispatch light' for load so they reduce their electricity costs. However, the proposal is yet to resolve how DG gets paid for its output if it is 'dispatched' as load.

d) financing new generation projects

DG owners are price takers for their electricity output. Attempts are made to manage spot price risk by using the hedge market but this is volatile and has limited liquidity.

Renewable generation projects involve a high upfront cost to construct and this cost is recovered over the long life of the asset. Regulatory certainty is therefore critically important to the bankability of these projects.

14 What are your views on whether current arrangements will ensure sufficient new generation to meet demand?

The IEGA strongly agrees with the EPR Report that there is "*the potential need to build a lot of new generation*".[5]

The Report goes on to say[6]

> Some demand will be met by small scale generation such as rooftop solar panels. But larger scale grid connected generation will also be necessary to meet most of the increased demand. Developers already have projects with resource consents that could meet demand growth for at least a decade – providing a window to identify further projects for later development.

This comment, and the report in general, makes very little mention of small commercial scale DG. As discussed in the cover letter, DG of the scale owned by IEGA members provides significant benefits to electricity consumers. Members have consented generation projects that could be progressed in a stable regulatory environment.

As mentioned previously, this DG would provide economically efficient incremental no-regrets increase in electricity volumes that is closely matched to increases in demand.

One of the issues with grid scale generation is that the stepwise increase in electricity volumes applies downward pressure on spot prices impacting the likely return on investment – this factor which impacts investment timing is unlikely with small commercial DG.

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[5] https://www.mbie.govt.nz/info-services/sectors-industries/energy/electricity-price-review/consultation/first-report.pdf Page 34
[6] Ibid page 34

Vertical integration

17 What are your views on this assessment of vertical integration and the contract market?

IEGA agrees with the EPR that "*improving the depth and resilience of the contract market should be given high priority*". [7]

While this has been an area of focus of the Authority since 2010, volatility and lack of liquidity continue to be a problem. We suggest some fundamental changes may be required to achieve change that will improve competition in the generation and retail markets and therefore benefit consumers.

18 What are your views on this assessment of generators' and retailers' profits?

IEGA members' are price takers – they do not have the financial or physical resources to man a 24/7 desk to participate in the wholesale spot market.

Transmission

19 What are your views on the process, timing and fairness aspects of the transmission pricing methodology?

IEGA understands this question refers to the Authority's proposed transmission pricing methodology in its 2016 consultation paper.

Throughout the consultation on a revised transmission pricing methodology the IEGA has maintained the view that it is essential transmission pricing signals peak demand periods and developing transmission constraints. Peak demand is widely understood to be a key driver of infrastructure investment – both transmission and distribution infrastructure.

Signalling developing transmission constraints enables a competitive market to develop solutions which Transpower can contract with as an alternative to transmission investment.

Distribution

21 What are your views on this assessment of barriers to greater efficiency for distributors?

IEGA agrees that distribution pricing should signal peak demand periods and potentially encourage a reduction in consumption, increase in consumption from consumer owned generation or increase in output from small commercial DG, and that owners of these assets are compensated.

Consumers sign up to reducing demand during peak demand periods by going on controlled as opposed to uncontrolled tariffs. These consumers benefit from lower distribution tariffs – between 1c/kWh and 8c/kWh across New Zealand. This is the same for consumers with their own generation.

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[7] Ibid page 45

Currently small commercial DG receive no compensation from distribution companies for generating during periods of peak demand and reducing the volume the distribution company has to carry from the national grid. **The IEGA submits that this is inequitable.**

22 What are your views on this assessment of the allocation of distribution costs?

Part 6.4 of the Code requires that distribution companies charge DG owners incremental costs of distribution services. While the Authority proposed to change this in its May 2016 consultation paper, the Authority decided not to proceed with this.

The IEGA provided evidence in our submission that common costs to DG owners could be $20 – $40/MWh, equivalent to 25 – 50% of an average wholesale spot price of $80/MWh.

IEGA commissioned PwC to analysis the financial implications of these charges for members[8]. Payment of common costs resulted in a significant increase in average total operating expenses of 45% and 90% assuming common cost payments of $20/MWh and $40/MWh respectively.

Assuming members had also lost any Avoided Cost of Transmission revenue and faced common costs of $20/MWh and $40/MWh resulted in financing ratios that would be unacceptable to banks providing debt funding. There would therefore have been serious financial consequences for existing DG investors. For example, increasing the average net debt to total assets ratio to 61% and 87% respectively; increasing the net debt to EBITDA ratio to over 8 times.

In our view, the issue of distribution companies' allocation of common costs to small commercial scale DG has been well analysed and reviewed and the decision by the Authority does not need to be re-litigated.

23 What are your views on this assessment of challenges facing electricity distribution?

Again it is not only residential scale solar pv and other emerging technologies that can be connected to a distribution network. The IEGA submits there are opportunities and advantages for New Zealand from increased investment in small commercial DG. These DG assets provide services to distribution companies and must be compensated.

The benefits of distributed generation are it:

- currently provides 10% of New Zealand electricity by output (including utility-owned distributed generation) which is equivalent to over twice the output of the Huntly power station
- introduces competition resulting in lower regional electricity prices for consumers as well as enabling new retailers to enter the market with Power Purchase Agreements
- employs around 500 people across most regions of New Zealand
- results in rebates and distributions back to local communities. For example, Pioneer Energy has distributed approximately $75m over 15 years to its community trust shareholder

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8 See report at https://www.ea.govt.nz/dmsdocument/21168-independent-electricity-generators-association-attachment-a

- assists with security of supply. Many of IEGA members' distributed generation plant supplied their local regional networks prior to the grid being built so have a proven track record of reliable supply as they are designed to run islanded from the grid in an emergency loss of transmission. Recently one of our member's distributed generation plant provided emergency power to Grafton hospital when Vector lost power
- avoids or defers distribution network and transmission investment
- is complementary to consumer load management, These network connected services have been incentivised to flatten more than 20% of the New Zealand electricity system's peak demand.

As well as contributing to New Zealand's renewable energy target, distributed generation also improves New Zealand's energy productivity. Energy productivity includes the cost of producing and delivering electricity. Distributed generation can be built at an LRMC equivalent to grid connected generation. Distributed generation is usually located closer to electricity users than grid connected generation and uses only the local network to deliver electricity to users. Grid connected generation (by definition) uses the transmission grid and the local network to deliver electricity. Transporting electricity results in lost energy (due to resistance). Recent data shows 1,239GWhs (3.2% of total electricity injected) was lost while travelling over the transmission grid; 1,670GWh (6%) was lost while travelling over distribution networks.[9] This is equivalent to the output of the Huntly power station.

Summary of feedback on Part four

24 Please summarise your key points on Part four.

As requested the summary of IEGA's key points on Part four are below. This is a summary and to fully understand this summary it is important to read the substantive answers to questions on Part four above.

Barriers to competition in the generation sector:

IEGA agrees with the EPR Report that the limited depth of the contract market is one of the factors inhibiting expansion or new investment.

However, there are a number of other barriers which are discussed in more detail in answer to question 13 but the headlines about the IEGA's concerns are:

Government environmental obligations:

a) consenting or re-consenting is a lengthy and expensive process (eg, it took 19 years to re-consent a ~1MW hydro power station and cost over $0.5 million)
b) the NPSREG, which categorises small commercial DG as of national significance, does not provide clear direction and must be more prominent and taken more seriously

[9] Top Energy took into account the economic value of lost energy (~6% in their case) when deciding to invest in distributed generation compared with investing in 110kV lines. Top Energy application for an exemption http://www.ea.govt.nz/dmsdocument/21586

c) engagement in local or central government policy changes requires resourcing that IEGA members individually do not have
d) the approach to access to and fees in relation to Department of Conservation resources is variable across New Zealand

Generation market obligations:

a) Difficulty and issues relating to negotiating with monopoly distribution companies for connection and charges
b) It is bizarre that investors in new DG have to negotiate with Transpower for services DG provides when Transpower competes with DG to deliver electricity to end consumers
c) The Authority's responsiveness to breach investigations is slow (over five years for one case). The Code is also complex and confusing. For example the Authority's real-time pricing proposal has taken into account the contribution of load to reducing peak demand and spot prices but has not identified a way of compensating DG for providing the same service.

Financing new generation projects:

DG owners are price takers for their electricity output. Attempts are made to manage spot price risk by using the hedge market but this is volatile and has limited liquidity.

Renewable generation projects involve a high upfront cost to construct and this cost is recovered over the long life of the asset. Regulatory certainty is therefore critically important to the bankability of these projects.

Will current arrangements ensure sufficient new generation investment?

IEGA notes the limited commentary in the EPR report about small commercial DG. This DG can provide economically efficient incremental no-regrets increases in regional electricity volumes that are closely matched to increases in regional electricity demand.

Vertical integration

- IEGA agrees with the EPR that "*improving the depth and resilience of the contract market should be given high priority*". [10]
- Some fundamental changes may be required to achieve change, as efforts to improve liquidity have had limited impact since 2010.

Transmission pricing methodology

- The IEGA strongly supports a transmission pricing methodology that signals peak demand periods and developing transmission constraints. Signalling developing transmission constraints enables a competitive market to develop solutions which Transpower can contract with as an alternative to transmission investment.

[10] Ibid page 45

Distribution

- IEGA agrees that distribution pricing should signal peak demand periods and encourage a reduction in consumption, increase in consumption from consumer owned generation or increase in output from small commercial DG, and that owners of these assets are compensated. Consumers are compensated with lower distribution tariffs when they sign up to controlled as opposed to uncontrolled tariffs (between 1c/kWh and 8c/kWh across New Zealand). However, small commercial DG receive no compensation from distribution companies for providing the same service (namely generating during periods of peak demand and reducing the volume the distribution company has to carry from the national grid). The IEGA submits that this is inequitable.

Solutions to issues and concerns raised in Part four

25 Please briefly describe any potential solutions to the issues and concerns raised in Part four.

The allocation of distribution company common costs to DG has been thoroughly analysed by the Authority and does not need to be re-litigated by the EPR Panel.

The following potential solutions could address the majority of the IEGA's concerns outlined in answer to questions in Part four of the EPR Report.

The IEGA suggests a pragmatic approach across the policy spectrum to address problems caused by the low scale of generation capacity for small commercial DG.

IEGA suggests that the EPR Panel investigate a de-minimus threshold for small commercial DG less than 10MW (but not connected behind a consumer's meter). This de-minimus of <10MW should be included as a starting point in key policy, terms and conditions and rules.

Below the de-minimus as a default, all monopoly providers (government, regulators, distribution and transmission providers) should put in place standardised rules, terms and conditions and policies.

A monopoly provider should then have to prove the need for any change to these default arrangements and if any of the default arrangement is changed the government is obliged to review all of the default arrangements together to ensure ongoing consistency. We recommend a cross-agency team decides on low cost standardised arrangements taking into account time, cost and quality.

Part five: Technology and regulation

Technology

26 What are your views on this assessment of the impact of technology on consumers and the electricity industry?

Small commercial DG is the same as emerging technologies like batteries – and provides the same potential benefits. IEGA warns about the risk that government policy and regulation focuses on this 'bright shiny new thing' to the detriment of existing assets or technologies (eg imposing barriers or costs that have unintended consequences).

27 *What are your views on this assessment of the impact of technology on pricing mechanisms and the fairness of prices?*

Consumers are making choices to invest in their own electricity generation at their own 'required rate of return'. This rate of return will be different to that of utility scale generators. Further, this consumer investment is impacting the need for investment by utility scale companies (ie saving them money). IEGA caution government and regulators from imposing their paradigm onto the decisions or choices made by consumers.

28 What are your views on how emerging technology will affect security of supply, resilience and prices?

The IEGA appreciates the forward looking independent analysis undertaken by Transpower in its Te Mauri Hiko report and other recent reports. Change is constant and it is important that all participants have access to quality information to engage in any decisions that need to be made.

Regulators in fast changing and disruptive markets need to ensure that natural competition prevails, and not become the disruptors and create barriers.

Regulation

29 What are your views on this assessment of the place of environmental sustainability and fairness in the regulatory system?

The IEGA supports the government providing guidance to regulators relating to expectation on environmental sustainability and fairness. This avoids any ambiguity. Every agency is part of the overall regulatory system and should be held to account to achieve the government's priorities.

The International Energy Agency (IEA) identified multiple public and private benefits of increasing energy efficiency and renewable energy use – copied below[11].

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[11] Source: Page 5 http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-strategies/consultation-draft-replacement-new-zealand-energy-efficiency-and-conservation-strategy/draft-replacement-nzeec-strategy.pdf

Multiple benefits of increasing energy efficiency and renewable energy use[1]	
Public benefits	**Private benefits**
Employment and market growth in energy efficiency and renewables	Cost reduction, energy affordability, low energy prices
GDP growth	Productivity, competitiveness, product quality, employee comfort and satisfaction
Productivity and competitiveness	
Reputational benefits from reduced environmental impacts	
Energy system resilience and security	Reputational benefits from reduced environmental impacts
Reduced reliance on imported fuels	
Emissions reductions	
Improved air quality	Health and wellbeing, comfort, reduced respiratory illness
Reduced public health costs	

Under the current arrangements the Authority does not consider these multiple public and private benefits in its analysis of proposed Code amendments. This might create some outcomes that are not fully aligned with the government's renewable energy target, government energy policies in total or New Zealand's international climate change commitments and targets.

31 What are your views on this assessment of gaps or overlaps between the regulators?

The IEGA strongly submits that all the regulatory functions associated with monopoly transmission and distribution networks be undertaken by the Commerce Commission.

The Commission is already responsible for regulating investment, revenue and quality for Transpower and distribution companies. It regulates these aspects as well as prices, access and technology for a number of other network sectors – gas, telecommunications, airports, ports.

Consolidating regulatory activity under one regulator would also eliminate duplication of effort – for example when both the Authority and the Commission consulted at the same time on the impact of emerging technologies from their own perspectives and industry participants had to make submissions on both reports.

32 What are your views on this assessment of whether the regulatory framework and regulator's workplans enable new technologies and business models to emerge?

The IEGA suggests that the Authority's efficiency and market based focus has the potential to be overly complicated and constricting as new technologies and business models emerge.

For example, development of real-time pricing includes an option for the demand side of the market to bid into or participate in the wholesale spot market. Reducing demand when it looks like there are going to be high prices will reduce the amount the consumer pays. However, DG is on the same 'side' of the market as demand. If DG increases output to meet peaks in demand when it looks like there are going to be high prices this will reduce the spot price but there is no mechanism for DG to be paid for this service.

33 What are your views on this assessment of other matters for the regulatory framework?

The statutory objectives for the Authority, in the Electricity Industry Act 2010, and for the Commerce Commission, in Part 4 of the Commerce Act, are very similar. We understand they were designed by officials to be the same. However, the two regulators have different interpretations of this statutory objective. IEGA suggests that EPR recommend a review of the interpretation of the statutory objectives and an alignment in the approach by the two regulators.

In addition, this review and alignment should result in the same approach to wealth transfers in the analysis by both regulators. The Commission includes wealth transfers (and a recent Court decision has confirmed this approach is correct). The Authority does not include wealth transfers.

The IEGA also recommends consideration of enabling merits based reviews of decisions by the Authority – consistent with the Commission.

The IEGA suggests a timeframe for completing any changes arising from this review be included in any revised legislation. This approach proved very effective after the 2009 Ministerial Review when the 2010 amendments to the Electricity Industry Act included a list of changes the Authority was required to implement within a specified time period.

Summary of feedback on Part five

34 Please summarise your key points on Part five.

As requested the summary of IEGA's key points on Part five are below. This is a summary and to fully understand this summary it is important to read the substantive answers to questions on Part five above.

Impact of technology on consumers and the electricity industry

Change is constant. IEGA cautions that trying to anticipate the impact of technology could over-complicate the rules, have unintended consequences and stifle innovation. Any changes must be consistently applied across all technologies that provide the same products or services.

Solutions to issues and concerns raised in Part five

35 Please briefly describe any potential solutions to the issues and concerns raised in Part five.

The IEGA supports:

- the government proving guidance to regulators on government's expectations in relation to environmental sustainability and fairness
- a review of the statutory objectives of the Authority and Commission to make the objectives as well as how they are interpreted the same
- the Authority taking into account wealth transfers – as the Commission does in its analysis
- the Commission being responsible for regulating all aspects of monopoly players in the electricity industry (as it does for other monopoly industries) thus eliminating the arbitrary split in responsibilities that exists currently
- including a timeframe for implementing any changes resulting from this EPR in legislation .

Additional information

36 Please briefly provide any additional information or comment you would like to include in your submission.

No other comments.

Appendix 2: Case Studies

1. Re-consenting Raetihi hydro generation power station, 19 year process at a cost of over $0.5 million

Raetihi is a small ~0.5MW hydroelectric power station located near Raetihi in the central North Island built in 1918 which has now supplied power to the Raetihi / Ohakune communities for 100 years

2000: Existing resource consents expired and NZ Energy applied to have these renewed. The application for renewal included an increased water take from the streams. All but two of the consents required to operate the scheme were given 35 year consent. However, the two main water takes were only given five years as the Council determined that more information was required before granting an increase in water take.

2007: NZ Energy, having undertaken the extensive and very expensive further monitoring, re-applied to have the remaining two consents renewed in line with the other consents along with the additional water that was originally applied for in 2000.

From this point on NZ Energy experienced a series of extensive and prolonged delays:

- Initially the processing of the consent was delayed due to staffing issues at Horizon Regional Council. This meant Horizon breached the statutory time frames. However there were no penalties or ramifications for doing this.
- Horizon continued having staffing issues and then decided to contract out the resource consent process to a third party. This meant further delays and costs to NZ Energy.
- Then the Council decided to take the processing back in house meaning yet further delays and costs. Each time the planner changed they had to get back up to speed with our application. This resulted in a huge processing cost to NZ Energy which NZ Energy objected to as this was at no fault of our own. NZ Energy subsequently refused to pay any further processing costs.
- Horizon then took the position of refusing to process the application any further because NZ Energy hadn't paid the bill. Horizon then went as far as giving written notice to liquidate NZ Energy.
- NZ Energy objected to this and the Court ordered Horizon to continue processing the application and ordered that NZ Energy didn't need to pay any further costs and the dispute in relation to processing costs was to be sorted at the end of the application process.
- During this time Horizon had been in the process of ratifying their resource management plan (The One Plan). The plan was changed significantly during the process of submissions, hearings, appeals etc and one of these changes was the introduction of the need for discharge consents at the point of abstraction, ie. the water that runs over NZ Energy's weir. Note that this isn't for the water discharged from the tailrace but merely the residual run of the river water over the weirs. A new yet ridiculous planning rule that had absolutely no purpose in this activity. NZ Energy had

the increased tailrace discharge consent approved as part of the 2002 approval and at the higher abstraction rate volumes that had been applied for but not yet granted.

- NZ Energy objected strongly against these consents as they weren't required in the 90 years previously and furthermore the residual discharge over the weirs was considered during the 2000 consenting process and deemed by the decision makers to be an integral part of that water take/structure in the river activity.
- Nevertheless, because it was a rule proposed under the revised One Plan, the rules of the RMA meant that it had to be considered. Had Horizon processed the re-application in 2007 in the statutory time frames then NZ Energy would never have been faced with this dilemma.
- This then meant NZ Energy had to lodge a new application just for the discharge consents over the weirs. Horizon then required further information on the effects of the discharges. This meant NZ Energy had to do significant further monitoring and engage further experts. The fact the scheme had these weirs in the river for 90 years were not taken into account.
- Finally after 6 - 7 years from when the 2007 re-application was made a hearing was held. However, the decision was appealed by Iwi and also NZ Energy.
- This lead to an order from the Environment Court to have all parties caucus in order to find any common ground and provide the Court their findings in advance of a hearing. The caucusing involved further expert work and also analysing water take scenarios including a scenario offered by the Court. This took a further 2 years.
- An Environment Court hearing was eventually held and the decision subsequently appealed by Iwi to the High Court. The appeal was upheld and the High Court referred the matter back to the Environment Court for a re-determination (on a point of law).
- The Environment court eventually re-issued their decision and part of that was that the parties were to agree on a set of conditions. This involved yet another prolonged process of exchanging information.

2018: In August the Environment court approved the conditions and the Court order sealed and the resource consent process was finished after 19 years from the date of the initial application.

The Raetihi Power Scheme has been in desperate need of a refurbishment for this entire time yet NZ Energy was unable to undertake the refurbishment until the legal consents to continue to operate the scheme were approved.

Genesis' neighbouring Tongariro Power Scheme has a capacity of 330MW. If they were to face the same degree of costs for renewing their consents then they would incur a $330,000,000 cost to renew their consents. A ridiculous thought, however a reality for NZ Energy. Clearly, de-minimus policies need to be implemented throughout local and central government in order to support small scale distributed generation.

The costs and delays mentioned above are common for consenting small scale distributed generation hydro power schemes and this doesn't take into account other processes like the Department of Conservation concession process and distribution company connection agreements.

2. Consenting and development of Inchbonnie Hydro power scheme