

Distributed Generation

Understanding the Market

Possible Policy Interventions



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Russell Longuet

Exergi Consulting Limited



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1 EXECUTIVE SUMMARY

Distributed or decentralized energy resources (DER) can be split into two distinct types, DG (Distributed Generation) and DR (Demand Response). The latter includes energy efficiency (usually requiring capital) and load shifting and shedding, which is a cost saving exercise.

While both segments have a part to play in providing a more secure and stable electricity supply environment, this paper addresses only the first segment, DG, which is the connection of small to medium scale generators at the distribution network level and the barriers to its increased adoption.

The paper is aimed at understanding the market in which DG is competing and proposes possible interventions based on this analysis.

There are three distinct *types* of DG:

- *Type one* is the standby generator designed for security of supply (eg for computer installations or hotels) or for peak lopping which may operate less than 100 hours per year. In Standby DG we include both generators that are synchronized with the Grid as well as those which are not but once the load is temporarily disconnected from the network they start up.
- *Type two* is that which is dependent on an intermittent or inexact fuel supply (eg run of river micro hydro, photovoltaics or wind generators), this is semi base load, in that it runs as much as it's fuel supply allows.
- *Type three* is base load generation which to be economic is usually of the CHP variety (eg Industrial co-generation or a domestic Stirling engine arrangement) or runs on a supply of free fuel, such as methane extracted from a landfill site or sewerage pipes or coal seams.

Type one arrangements are hard to justify if installed for peak lopping only (ref. Appendix IV), owing mainly to the capital cost of \$/MW installed. However, where a diesel or gas engine is installed for security purposes such as part of a computer uninterruptible power supply (UPS) arrangement, it can also be used economically to 'peak lop' when energy prices

are high or when system transmission capacity peaks occur. This use depends on price. That is, DG owners must receive timely control period (price) signals from their Distributor or peak buy back prices from their Retailer which provide sufficient incentive for them to act.

The type two arrangement is very location specific and entered into only after considerable monitoring of the fuel resource and an estimate of load factors have been undertaken.

The third type as a co-generation plant is again site specific but provided there is a sufficient heat sink to match the electrical and heat output of a generator, overall energy efficiencies in the 70-80% range can be reached and these efficiencies coupled with operating hours of greater than 6000 hrs per year usually provide viable projects. Most economic opportunities for this arrangement at the Industrial level have been utilized.

There are also distinct DG *size* bands as experienced in the New Zealand Market, with each having its particular barriers and issues.

- *Band one* is below 10kW which is typical for households and includes PV's, small engine gen sets, micro CHP and small wind mill battery chargers or pumps. Usually these systems include an inverter which produces harmonics. Harmonics need to be filtered out so that the quality of network supply to others is not compromised.
- *Band two* is between 10kW and 1 MW. This includes commercial standby generation usually diesel or gas engines or small gas turbines as well as some rural mini-hydro schemes.
- *Band three* is 1-5MW which is where Line companies might invest, or have an interest in generation. Diesels, mobile gasturbines, and small hydro are likely contenders here. Waste methane fuelled gas engines used at landfills or sewerage works are also typically in this range.
- *Band four* is 5-50MW which currently covers line companies investing in renewables (wind or geothermal or hydro) but line companies are required under the arms

length rules to have a separate company to undertake this investment.

Industrial co-generation installations and potentially Industrials investing in wind or tidal generation also come into this band. Co-gen systems may be biomass fuelled and/or natural gas/coal fuelled. Small hydro stations are also contenders. Typically there is a large proportion of renewables in this band. At the higher end of the band, because of short circuit current issues, a generator usually tends to connect directly to the (Transmission) Grid, leaving it outside our definition of DG.

There is another break-point within this band at 10MW. Above 10MWe¹ you are required to have TOU (Time of Use) metering (full half hour logs) and will probably be required to provide this information to the System Operator (Transpower) on a continuous basis. That is, offer into the pool. This has a compliance cost.

The largest 'questionable' DG in NZ at present is at Kinleith (35MWe), which is 'deemed embedded' for the purposes of Transmission charges but does connect through a three winding Transformer to the network 33 kV bus (via a normally open isolator) as well as the 110kV Grid. This was done as the cheapest alternative to limit short circuit current. The alternative to deemed embedding would have been a very expensive 11kV reactor. The electricity generated is all consumed at site. That is, the Kinleith demand is around 80MWe and the site is always a net importer of electricity, regardless of the fact that there is a Grid connection to provide the equivalent of reactors by using the transformers out to the grid and the transformers back into the site.

Note that the BHP/NZ Steel embedded generation is > 50MW and therefore falls outside this discussion paper. (refer Appendix 1 for a list of known DG schemes.

From the following analysis, we believe that residential DG (<10kW) is only likely to be economic if either the consumer remains a net purchaser at all times or has a TOU meter installed which allows generation to be fed back to the network at selected times of peak prices where a significant incentive price is

¹ MWe = MW electrical, a convention used to differentiate between MWth = MW thermal. This is particularly useful when doing energy balances for example with a co-generation system.

paid for energy and/or capacity by the retailer or lines company respectively. Unfortunately on hot summer days when every one is at work household load can be very small and excess generation is likely to be available. This is the time when energy prices are likely to be low. Typically only enthusiasts invest in this area and it is more for self sufficiency/security of supply reasons than a commercially economic payback.

Anecdotal evidence suggests that mini-hydros in the 0.3 to 2MW range can be economic investments provided that a reasonable/fair energy contract with a Retailer can be established.

The new draft regulations issued by MED October 2006 for discussion but aiming to be gazetted before Christmas cover many of the issues between Distributor and DG owner. However, there still appear to be ways by which a line company could choose to effectively negate the intention of the regulations, to the detriment of the DG owner.

We, note here that the World Alliance for Decentralised Energy (WADE) says in its 2006 market assessment that 24% of electricity output from newly installed power generation plants in 2005 was derived from DG up from 13% in 2002. There is an emerging global recognition that generation at the point of demand results in reduced need for costly investment in Transmission and possibly distribution networks as well as environmental benefits, reduced losses and increased security of supply.

As far as New Zealand is concerned it is the author's view that for improved uptake of DG one or more of the following should be in place:

- A. A regulation which requires retailers to provide a 'limited spread' Fixed Price Variable Volume contract (FPVV) to DG operators. 'Limited spread' refers to the differential between what the Retailer would charge a load at the point of connection (for energy only), compared to the price a Retailer would pay a Distributed Generator at the same point of connection. Using the **Energyhedge**² approach this

² 'Energyhedge' is an inter-generator financial platform requiring participants to continuously post two-way prices (buy and sell) on 0.25MW quarterly hedge contracts going out (currently) two years. See www.energyhedge.co.nz

- 'spread' should be limited to 10%. Note that the Photovoltaic association has negotiated a zero spread arrangement for residential DG with Contact. That is Contact will pay the retail price for fed back electricity for < 5kW residential installations.
- B. If item A above were mandated, then there would be no need for Distributors to be Retailers and neither would there be any requirement/need for Distributors to be able to deal in financial instruments such as hedges (or contracts for differences).
 - C. Line companies should be required to provide a rebate of Transpower's interconnection charges based on the DG output at the times of regional peak.
 - D. If the regional DG is aggregated, the Distributor will be sure that if a 'control period' is indicated it can count on at least 60% of the aggregate DG capacity being started. This has considerable value to certain Distributors. The value of lost load should be considered in these calculations and/or the value of delayed network or Transmission investment. (Orion's approach to using DG owned by third parties).
 - E. DG operators should be required to pay for any DG specific upgrade of the network required to connect to the network. This can be paid 'up front as a lump sum' or amortised over the life of the plant at the DG operators option. (Two way metering, protection relays and a transformer or line upgrade if necessary to support the DG could be possible inclusions). The line company should be required to obtain three separate quotes for the equipment and installation and the DG owner should have the option of procuring the necessary assets himself. In the future, should a third party benefit from the line upgrade paid for by the DG owner, a rebate or reduced line charge should accrue to the DG owner.
 - F. Line Company's need to compensate DG operators for Reactive power generated (KVARs).
 - G. If there is a political desire to increase the uptake of DG, a subsidy may be required. One such incentive would be a \$/MW installed contribution for new DG installations. This is what operates in the UK and underlies their recent sustainability policy, or a \$/MWh subsidy as used in Holland.
 - H. Another form of subsidy for renewables (again which links into the Governments framework on sustainability) is an MRET scheme. That is, a Minimum Renewable Energy Target scheme underpinned by tradable renewable energy certificates (RECs) as seen in a few countries but in particular Australia. (refer item 9). The Australian scheme should be modified and improved for New Zealand by having both Thermal and Electrical RECs where a thermal REC is about a third of the value of an electrical REC. This allows a balanced incentive for co-generation versus pure electrical generation, a feature missing in the Australian scheme.

Under these schemes, effectively all consumers of electricity pay a very small extra amount which is used to provide a worthwhile (in the region say of 3c/kWh) subsidy to new renewable generation.
 - I. With the thresholds regime, governing Distributors, the issue of cross-subsidisation by Distributors of inefficient generation from monopoly profits should no longer be a potential issue. There is an argument that the arms length separation rules for Distributor owned generation between 5 and 50MW could be relaxed, in particular the need for an independent board for the generation subsidiary.

2 INTRODUCTION: Definitions and Pros and cons of DG

2.1 Definitions

After considerable discussion we believe the definition of DG for New Zealand can be stated as:

Distributed Generation in New Zealand includes any electrical generator below 50MW which is connected at the distribution network level, or which is used when a load is temporarily disconnected from the network to reduce network load.

This definition *includes* standby and base-load generators and suggests a preference for locations near to loads where the generated electrons are consumed before leaving the premises let alone the region. Generators such as ‘Pioneer’³ are included.

This definition *excludes* generators connected directly to the grid, which must offer into the pool⁴. These are usually merchant generators and currently those owned by the three SOEs (Mighty River Power, Genesis and Meridian) as well as Contact and Trustpower.

³ Pioneer generation Ltd runs a number of small hydro stations in central Otago and is Trust owned ref. www.electricityinquiry.govt.nz/submissions/288.pdf; www.pioneer.gen.co.nz

⁴ Refers to the NZ electricity spot market pool where offers and bids are received, generators dispatched to meet demand and nodal spot market prices discovered every half hour - refer section 6

The recent DG regulations paper for discussion issued by MED which concerns the connection contract issues between a potential DG owner/operator and the regional line company (ref Appendix III) has defined DG as plant that:

- (a) is connected or proposed to be connected to a distribution network, or to a consumer installation that is connected to a distribution network; and
- (b) is capable of exporting electricity back into that distribution network.

Orion has made the following comment in relation to DG definition in their Pricing Guide for 2006:

Embedded generators, also known as ‘distributed generators’ are generators located at a home or business which are capable of generating electricity for that home or business’s own use. They may also be capable of putting surplus electricity back into our network. These generators can take many forms; diesel generators, wind turbines and solar panels are the most common.

Distributed Energy Resources include both DG (Distributed Generation) as well as DR (Demand Response) as shown in Fig 1.

Figure 1 is effectively a schematic of consumer

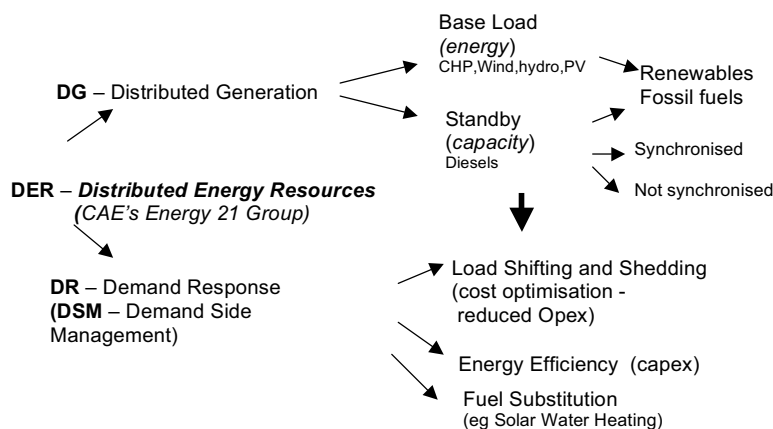


Figure 1: Split of Distributed Energy Resources

response *options* to Price and Security issues. That is, a consumer has a number of options, which are captured in this diagram, to react to volatile or high electricity prices or poor security of supply, where Generation, transmission or distribution failure or constraints cause power outages and/or high prices. However, this paper focuses on DG rather than DR.

We have chosen to split the sizes of DG into four distinct ranges to match the likely applications or owners. These are:

- **Less than 10 kW** – this includes all residential sites and rural schools. Typically small petrol engine sets, micro hydros and Photovoltaics are used.
- **10kW -1.0MW** – This includes commercial, hospitals, hotels, computer centres, ports and airport applications. Typically large diesels and gas engines and mini-hydro.
- **1.0-5 MW** – This is a typical size for a lines company where the generator is not renewably fuelled. Typically Large Diesels and gas engines and small gas and steam turbines. Currently lines companies can invest in any DG if <5MW or 2% of their peak, without legal complication. It is also the unit size for renewably fuelled gas engines using methane extracted from landfills or sewerage works or coal seams.
- **5-50MW** – This is mainly base load industrial applications such as a turbine in a co-generation application or a lines company wind farm. If DG > 5MW but < 50MW or 20% of Peak a lines company may currently invest but must undertake corporate separation of the DG venture - (known as the ‘arms length rules, requiring separate Boards).

2.2 The Benefits and Detractors of DG

Benefits of DG

- Reduced line losses – generation closer to load
- Increased security of supply – shorter

supply chain & diversity of smaller types of DG.

- Reduced likelihood of binding constraints on Transmission feeding the region which create higher nodal prices
- Often renewably fuelled – as a rule DG is usually more fuel flexible (wind, waste methane, wood gasifier using a local resource). Environmental advantages.
- Combined Heat and Power (CHP) configurations are more energy efficient than Grid connected electricity only Generators (GG’s)
- Can improve local voltage level
- Can reduce Transmission costs and/or delay upgrades
- Can reduce Network costs and/or delay upgrades
- Can generate reactive power, reducing local loadings and substituting for capacitor banks.
- Aggregation of regional DG’s can be bid into the Reserves market.

Detractors of DG

- Higher cost per KW to install than the bigger grid connected generators (eg Whirinaki)
- Possibly more expensive fuel (eg supply contracts say for Gas are likely to have a higher price/GJ than for a large SOE)
- Transmission capacity is frequently cheaper to build than small local generation units, but often needs to be built anyway.
- Intermittent generation may increase frequency keeping costs. Causer pays regime would see an additional burden on say a small (0.2-1.0MW) local wind turbine operation.
- Local network implications on planning, operations and safety.
- Negotiation of connection can be complex and take a long time.
- Ripple control is effectively free to Transpower.

3 THE DG ENVIRONMENT

To develop this paper, interviews were undertaken with a number of the entities detailed in the diagram below (also refer appendix II).

Key issues of interest were:

- Lines companies wanting to be Retailers. Understanding the energy sales bargaining power (or perceived lack of) and lack of Board control of Lines companies wishing to invest in DG over 5MW under current regulations.
- The new retail benchmark contract issued by the Electricity Commission for consultation (for DG < 40,000 kWh pa. Which is ~ 5kW base load)
- Connection issues/costs/prevarication particularly if a DG proposer were not a lines Co.

- Conversely if a lines company's asset management plan (public) indicates a future possible power station site it is important to avoid speculative buying up of access rights/land by unconnected parties
- Financial justification/feasibility/value of DG for its different segments (roughly: residential, commercial, lines co's, Industrials), both to the investor and the Country.
- RMA issues and the desire for regions' environmental regulators to see DG as a local resource worth promoting.

These issues reinforce the necessity to understand the market structure and mechanisms within which DG is to operate. The rest of this paper is aimed at addressing that issue.

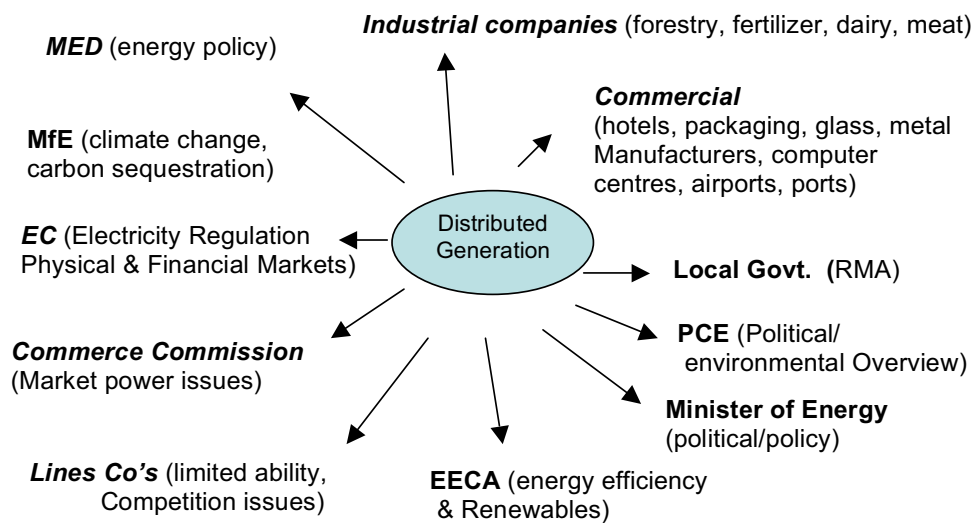


Figure 2: The DG Environment

4 POLICY GOALS FOR DG

The goals to improve the uptake of DG can be expressed as:

Positioning DG in the NZ electricity market as a viable option by reducing 'barriers to entry' for DG investment.

The following list encapsulates those policy goals.

- The connection costs to the network should not be excessive
- If required to Offer and Bid into the electricity pool (<10MW), the rules should be varied to allow use of **net** bids if an entity's generation offers are always smaller than its demand bids. Another alternative may be the acceptance of a persistence model for implicit offers to the pool for industrial co-generation, similar to intermittent wind generation (ref Electricity Governance Rules for wind generation).
- Sale of excess generation at the spot price to the incumbent Retailer as of right. This is able to be done directly with the clearing manager, but often it is easier to deal with one's local Retailer. Usually this can be accomplished but there is no obligation on the Retailer to do so.
- Ability to obtain FPVV (Fixed Price Variable Volume) contracts for excess generation from a Retailer with 'limited spread' between that FPVV energy *supply* contract and an FPVV energy *demand* contract at the same or electrically/locationally similar offtake node.
- Power quality requirements not to be unreasonably excessive - in particular a common standard for residential inverters <10kVA which requires no further individual electrical analysis/compliance document/decision from the lines co.
- Favorable status under RMA to have DG recognized as a local resource.
- Protect project originators from Line company negativity or delay to originators' proposals for connection /stability studies/ excessive compliance costs which need to be done by the line company.
- clarify metering protocols for different DG sizes. Ensure any new metering systems provide separate registers for each power direction. Improve metering standard/ functionality and reduce cost
- Move DG from tailored/niche solutions to more standard/pre-engineered products – (*mainstream DG – particularly at the residential level*)

5 WHAT DG OPERATORS NEED TO BE ECONOMIC

DG does not suit everybody.

The first consideration is the amount that electricity costs, as a percentage of one's overheads.

For instance, this may be 15% for a residential customer, 5% for a commercial customer, and 10% for a large Industrial. Clearly, the bigger the percentage and dollar amount the more focus the issues get. For residential customers, a higher income bracket will be a significant influence on ability to invest in DG.

Another consideration is the region in the country in which one resides. Clearly the more remote and/or capacity constrained the more beneficial DG is likely to be. It is also a customer specific issue as to the value of security. What is the consumer's *voll* (value of lost load)?

A third consideration is fuel. For instance a higher average regional temperature will favour PV's and solar water heating substituting for electricity generation from the Grid. Similarly a flowing river with a high head or consistent volume is necessary for a small hydro and

biomass in abundance is necessary for wood gasifiers for instance.

Once these issues have been considered, it is necessary to get an energy contract that provides sufficient revenue and a lines contract that has a limited cost and does not display any double dipping by the lines co. That is, assuming as a consumer you are already paying a line charge (usually of the form $X \text{ c/day}$ residential or $Y\$/\text{kW MD}$ for Industrial), you should only need to pay an additional 'connection assets charge' specific to the connection of your DG and not another line charge, all things being equal.

If the 'connection charges' include upgrading the line, then you need to anticipate any rebates from other parties who might subsequently utilize any new capacity.

You need to work out your operating regime then do a cashflow analysis.

The discounted cashflow analysis needs to have a positive NPV, where the discount rate reflects the relative riskiness of the project over and above the cost of capital.

6 THE ELECTRICITY MARKET

To facilitate discussion on issues related to the sale of surplus electricity generated from DG installations, an understanding of the peculiarities of The New Zealand electricity market can be helpful.

The NZ electricity market can be simply depicted by three arms as below:

- 1 **Physical** – ie the flow of electrons when a consumer turns on a switch.
- 2 **Payment for the physical** – through retailers paying the pool and the pool paying the merchant generators at the various spot prices.
- 3 **Financial** – where spot price risks are mitigated.

So, the consumer turns on the switch and the electrons flow by the laws of physics from the remote Generators through Transpower, through the local distributor to the consumer. (For some large Industrial consumers who are connected directly to the Grid, the Distributor is by-passed.)

At the time of consumption, the spot price is **not** known by the Direct consumer or the Retailer, but is established by price discovery when the actual demand (post consumption) is matched with the supply stack established before consumption. The system operator

dispatches generation from this merit order stack and a set of prices are discovered. The pool price is therefore set effectively by the last dispatched generator - (there are exceptions such as Spring washer effects, but they are beyond the scope/purpose of this paper). By this process, some 255 nodal prices are established each half hour in arrears.

In the second arm, the consumed electrons need to be paid for, which is done by the pool clearing manager paying the Generator the relevant nodal spot price (spot 1) on the amount dispatched from that injection node. The Pool receives a payment from the Retailer for the energy consumed at the relevant demand nodes at the relevant nodal price (spot 2). As Spot 2 in aggregate is greater than Spot 1 a surplus of money is accumulated in the Pool. This amount is caused by losses and constraints on the grid. These 'loss and constraint rentals' are currently paid to Transpower who pass them through to Distributors in proportion to the Transmission charges the Distributor pays Transpower on their relevant connection assets. These rentals are however an ideal source of funds to hedge against location risk and it is likely that they will in future be used for this purpose by the Pool giving them to the Retailers who would forward them to their consumers, thereby

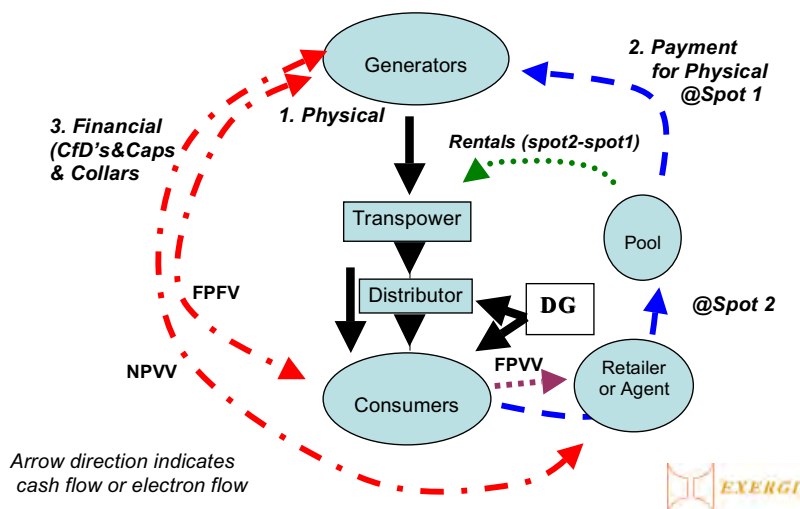


Figure 3: The New Zealand Electricity Markets

mitigating the nodal price peaks caused mainly by binding modeled constraints on the grid.

There are two other important considerations with instantaneous matching of supply and demand. The first is frequency keeping which currently costs about \$60Million pa and the second is the reserves market, where generation and/or sheddable loads are paid to be 'in reserve'. There are two markets: the 'generate/shed within 6 secs' (fast) and the 'generate/shed in 60 secs.'(sustained – which has to remain in/out for 15mins). This is necessary to deal with unplanned outage, either generation plant failure or transmission, leading to supply shortage.

We now look at the third arm, the financial or hedging market. The Retailer can either act as an agent for a large consumer and for a fee, pass through spot prices to the consumer. This puts the spot price risk on the consumer who will look to Generators (natural issuers) to purchase CfD's (contracts for differences, colloquially known as Hedges), or caps or collars. CfD's are FPFV (Fixed Price Fixed Volume) contracts. CfD's are a liability regardless of the amount of physical electricity one takes.

We note here that it is often not possible to obtain a CfD at the node of off-take but only at a generation node. This is an additional mismatch risk to a consumer operating in the spot market.

However, the more usual operation of a Retailer is to provide a customer/consumer with an FPFV (Fixed Price Variable Volume) Contract. As the Retailer is paying the Pool 'spot', the risk rests with the Retailer, who should seek a hedge from a generator to mitigate its spot price risk. However, the big 4 Generators own large retail bases (hereafter referred to as Gentailers) and provide their retailer with an **implicit** hedge. On the diagram we have used NPVV (no price variable volume) contract for the implicit financial arrangement within Gentailers. If vertical integration were not allowed, then these Retailers would have had to obtain **explicit** hedges.

There is also an inter-Gentailer hedge trading platform known as **Energyhedge**². The four big

Gentailers were founding members of **Energyhedge** and Trustpower has recently joined. As some generators are predominantly hydro and others thermal, inter-generator hedging is a prudent risk management technique.

Energyhedge requires participants to post two-way prices for standardised 0.25 MW contracts designated at Haywards. The participants have to post prices with a limited spread, for quarterly contracts out 2 years, with monthly contracts for the one or two early months. We anticipate that the **Energyhedge** protocol will be extended to require quarterly bids and offers out 3 years and indicative price matrices for other key nodes based on historical location factors using the Haywards quotes.

While participation in **Energyhedge** is theoretically open to anyone who wishes to meet the rules, in reality, consumers are not in the business of being market makers for electricity prices. That is, they would be speculating by posting two way prices with a limited spread at Haywards on a continuous basis. This means that a consumer interested in obtaining a hedge will need to transact through a Gentailer participant.

This forward curve derived by **Energyhedge** should benefit feasibility studies into DG, even though it is likely to only extend out three years. The value of Energyhedge is not so much the number and size of the transactions that go through it (they are relatively limited), but the forward price curve that is publicly available.

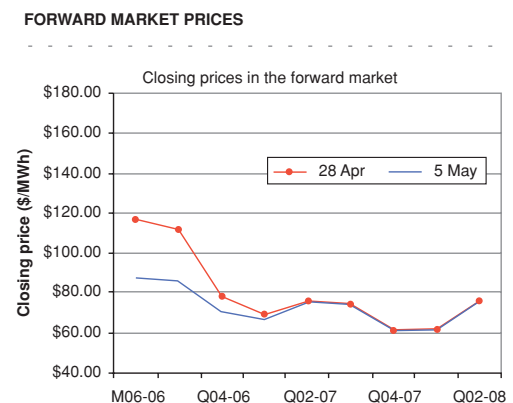


Figure 4: A typical forward price curve from EnergyHedge (www.energyhedge.co.nz)

² Ibid

A typical forward price curve from EnergyHedge is depicted in Figure 4. This curve was valid at mid May 2006. Mo6-o6 refers to the early month of June 2006, thereafter the prices are set by quarters.

The CfD

The CfD (Contract for Differences), is a financial instrument, where liabilities are established which are independent of the actual amount of electricity consumed or generated.

We outline in Figure 5 a simplified diagram showing the transactions between a Generator (and issuer of a hedge) and a Consumer (in this case being a purchaser of that hedge).

With regard to DG, an operator is in one of two situations. Either:

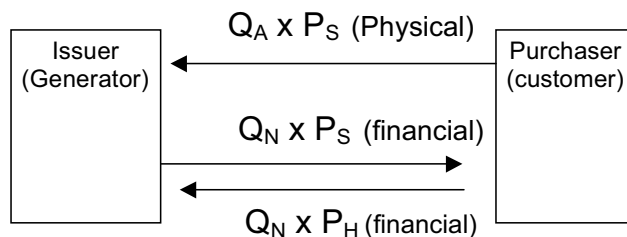
- The DG operator is generating less electricity, at all times, than he/she consumes. That is there is never net export to the grid. In which case the DG is a natural hedge and no additional electricity purchase contract is necessarily required to make the DG more feasible. (eg an embedded co-generation plant where DG output is less than the manufacturing plant demand is always a net purchaser)
- The DG operator is, in some or all circumstances, a net generator as seen by the Network. In this case the DG operator does

want some certainty of revenue but also preferably no risk of being exposed to spot price risk when unable to deliver. The DG operator cannot be sure of more than say 95% availability of its plant, therefore it optimally wants a contract which has no liability when the DG is down for any reason. This **would not be a financial CfD**, which would effectively create a liability to settle against the spot price during the periods when the DG was down, or up as the case may be.

On the other hand, if a third party spot consumer were to enter a contract with a DG operator to purchase electricity, the third party would want to hold a hedge contract to mitigate spot price risk on the amount of electricity that the DG was not supplying in times of DG failure. While the consumer could take a CfD with another Gentaileer,

this would create a situation where the consumer would be overhedged when the DG was operating correctly, assuming the consumer has a physical energy supply contract with the DG owner.

So the third party would optimally want a financial instrument which only came into effect when the DG was down. This could be an option. That is, a right but not an obligation for a consumer to settle a CfD - (A Gentaileer to sell a call option to a consumer). One simpler instrument may be a cap, allowing



$$\text{The Hedge} = Q_N \times (P_H - P_S)$$

Where: Q_A = Quantity Actual. Q_N = Quantity Nominal
 P_S = Price Spot P_H = Price Hedge

$$\text{Total payment} = \text{Physical} + \text{Financial}$$

(Whether 50% or 100% hedged, incentive to shed if the spot price is high, remains)



Figure 5: Hedges (the CfD) (the arrows indicate cashflows)

a hedge price settlement if the spot price went above say 10c/kWh. This would be even better if it could be operative only when the DG was forced out.

Alternatively, a 'b type' DG operator would be in the best position if he/she were able to obtain a reasonably priced FPVV physical contract from a third party. This party is most likely to be a Gentaileer where ***the DG output is insignificant in comparison to the generation assets and diversity of demand contracts of the Gentaileer.***

This type of contract would be ideal for a line company DG owner.

The question is what is reasonable when establishing an FPVV price for a DG operator.

There are a number of guiding possibilities.

- 1 At the relevant DG injection point, are there corresponding takeoff FPVV contracts? If so, what price level?
- 2 Does the DG cause capacity problems or instability in the local network? (this is not a direct issue for an energy contract, but

must be sorted out before a DG can inject back into the network).

- 3 Does the DG stabilize energy prices by reducing (modeled) constraints on the Grid?
- 4 Does the DG reduce or delay Transmission cost increases to the Network?
- 5 Should meters in houses with micro DG just run backwards, thereby offsetting the demand tariff or should two separate loggers be required?
- 6 Should all DG require two way TOU metering and therefore in residential situations a more focused tariff? (meaning that generation (and demand) at 6pm is worth more than at 1am say)

The key point established over this section is that Line Companies do not need to be Retailers and do not need to have the ability to trade hedges, provided that a reasonably priced FPVV contract can be obtained from a Retailer.

The other alternative is for a DG operator to choose to sell directly into the spot market if that is deemed more desirable.

7 ENERGY CONTRACTS

From the preceding section:

- the optimum contract that a DG (producing electricity only for sale, as opposed to an industrial co-generation arrangement) owner could have, is a reasonably priced FPVV contract. As noted previously, we believe that for >10kW loads this should have a 'spread' limited to 10% when compared with an FPVV contract for energy purchase at the same or electrically similar node and the spread should be zero for less than 10kW loads.
- The optimum contract a *purchaser* of electricity (excluding self generation on site) might want may be either an FPVV contract or a spot and hedge contract
- A Retailer is the only party that can effectively bridge this potential mismatch, because the Retailer is in the best position to manage the spot price risk on two counts.
 - 1 The retailer is vertically integrated and as such is privy to a natural but flexible hedge and
 - 2 The Retailer is probably a participant in Energyhedge and can pick up the best priced CfD's from the other Participants (the big Gentailers).
 - 3 The diversity and scale of the Retailer's loads, of which the DG is a fraction of a percent. The DG is insignificant in comparison to the total load supplied by the Retailer who is effectively buying physical electrons at spot prices from many sources via the grid.
- The FPVV contract from the Retailer can additionally include the line charges (see next section – section 8), or a separate line contract between the DG owner and the line company may be entered into. However some line companies are not keen to have direct contracts with DG owners as their administration systems and databases are not set up for this.

8 LINES COMPANY CONTRACTS

Line companies generally bill Retailers for applicable local network charges (their own) and Transmission charges (from Transpower). The Retailer then bundles these charges up and on-charges the consumer for line charges and energy charges and EC levies on the same invoice.

The Transpower charges are split into connection and interconnection charges. The former relates to assets specific to the consumer, or set of consumers, and the interconnection charge is currently a postage stamp single charge across the country of ~\$60/kW of MD. MD is maximum demand and is defined as the average of the 12 highest half hour peaks over the last twelve months. This means that if a DG is down for 6 hours and no demand response is undertaken a client will be straddled with the resulting MD and associated Transpower interconnection charge for the next 12 months. Note that there is a proposal out for consultation which splits the country up into 4 regions and the MD will be calculated from the X highest peaks over the last 12 months in the couple of hours of the morning and evening system peak periods. X will remain 12 for the upper North Island and upper South Island but be set at 100 for the lower North Island and lower South Island.

The new Transmission pricing policy should marginally benefit DG in so far as it is based on the REGIONAL COINCIDENT peak (as seen by Transpower and charged to the line Co) - the MD calculation of that peak is covered above.

The network charges are varied between each local line company and within each company to the extent that there are hundreds of different network charging structures across the country. Suffice to say that efficient pricing structures incentivise the consumer to do what

the network company believes is the best way to optimize the networks assets in terms of reducing peaks (capacity which needs to be provided), keeping power factor close to unity (excessive current/voltage drop considerations affecting *real* power carrying capacity) and ability to shed load in circumstances that require limitations on power transfer from time to time.

A typically efficient line charge might have a kVAh charge (disincentivising poor power factor) on all power consumed and a peak KVA charge covering the network peak hours plus a daily charge recovering site specific connection assets.

In this regard any embedded DG with a synchronous generator (as opposed to an induction generator or PV) would benefit from this type of network charging in so far as the synchronous generator can generate KWh (active) and KVARhs (reactive) thereby reducing the (efficient) KVA line charge for real net demand, considerably more than if the network charging structure were inefficient and based on KWh and KW charging alone.

So it is important to get networks to create fewer and more efficient line charging schemes so that DG is better incentivised.

We also note that the 28 (current) distributors are each at different stages of investment with respect to load growth. This results in some networks having over capacity (eg Powerco - due to lower than expected regional consumption growth). This means they do not derive much benefit themselves from new DG or alternatively Orion whose network is near its capacity limit and who is using DG to effectively delay new investment as the optimum way to contain network charges.

9 OVERSEAS METHODS WITH DG

Australia

When a DG proposal is mooted, a thorough system stability analysis has to be carried out by the local network. This is expensive and takes many months and must be paid for by the proponent. However, where the DG is renewably fuelled the Australian Greenhouse Office (AGO) have developed a REC scheme (*refer next section*) to effectively provide a subsidy of the order of 3c/kWh on the green electricity generated.

The programme was very successful in achieving the 2% target of increased renewable generation, however, once the target was achieved a new target was not set and the REC market died. The programme did however miss one important point. It focused on electricity rather than energy.

The downside of this Australian regime was that it did not sufficiently incentivise co-generation, where electrical efficiency is usually traded off against overall efficiency. (eg a wood fired condensing steam turbine may have a 34% efficiency with all output being electricity, whereas a wood fired backpressure steam turbine exhausting to a manufacturing process may have an 75% energy efficiency but only 12% of the output is electricity). If a REC system were adopted in NZ it should include both electrical RECs and thermal RECs so that co-generation, which is the most energy efficient process, is correctly incentivised. For instance a thermal REC might be a third as valuable as an electrical REC. This would incentivise a biomass co-gen over a biomass fuelled condensing steam turbine for instance.

Britain

Britain has publicly stated goals that aim to make 40% of residential energy consumption coming from renewables as well as improving the energy efficiency of consumption. As part of this initiative they have embraced wind farms and CHP stirling engines in homes. In various areas/regions, they have provided a regulatory \$8.8/kW/yr incentive for 5 years from commissioning.⁵ There are renewables targets set for 2010 and 2015, current proposals are mainly wind.

Europe

The predominant incentive mechanism for renewable generation in Europe comes in the form of Feed-in-tariffs (FIT's). Essentially FITs are guaranteed payments for up to 20 years for any renewably fuelled electricity DG injecting into the network.

Similar to RECs (in Australia) the renewables are effectively subsidised by levying a very small amount across all consumers in the country. This funding charge can be a levy on kWh's consumed or a small additional levy on rates. The former would appear to be the more economically efficient method.

The evidence in all these cases suggests that progressive Governments believe that DG, particularly renewably fuelled DG, is a desirable resource, supporting diversity and security and should be encouraged. This is interpreted to mean that if an optimal volume of DG does not occur through normal commercial activity, an incentive should be provided.

⁵ Paper to CAE's DG conference in Auckland 15 June 2006. Jonathan Russell 'DG and the UK regulatory environment'.

10 MANDATORY RENEWABLE ENERGY TARGETS (MRETS) AND RENEWABLE ENERGY CERTIFICATES (RECS)

The essence of the Australian scheme is as follows:

- a The Federal Government decided that they would target a 2% increase in renewables by 2005 which equated to 9500GWh pa. This meant that the Nation's renewables content of generation would move from 10% to the target of 12%.
- b The obligation to make this improvement would fall on the retailers of electricity proportionately. That is, if Retailer X had sales of 10% of the nation's demand then Retailer X would be responsible for providing 10% of 9500GWh of new renewables, that is, 950 GWhpa.
- c By building MW of renewables the owner created REC's (Renewable Energy Certificates), the units of which were 'renewable energy generated' (kWh) .
- d Each year the Retailer was required to lodge his share of RECs with the AGO (Australian Greenhouse Office).
- e If Retailer X had not generated sufficient REC's to cover his obligation, the Retailer was required to purchase the shortfall either from another party with excess RECs or from the AGO⁷ at the fallback price of 4c/kWh.
- f The result of this was that an incentive was established, for anyone interested in investing in renewables, to the tune of say 3c/kWh (ie something under the fallback cost of 4c/kWh), as the trading market in REC's developed.

⁷ The Australian Greenhouse Organisation ref www.ago.org.au

11 RECOMENDATIONS

As far as New Zealand is concerned it is the author's view that for improved uptake of DG one or more of the following should be in place:

- a A regulation which requires retailers to provide a 'limited spread' Fixed Price Variable Volume contract (FPVV) to DG operators. Limited spread refers to the differential between what the Retailer would charge a load for energy at the point of connection, compared to the price a Retailer would pay a distributed generator for energy at the same point of connection. Using the Energyhedge approach, this 'spread' should be limited to 10% for installations >10kW and should be zero for installations below 10kW.
- b If item a. above were mandated, then there would be no need for Distributors to be Retailers and neither would there be any requirement for Distributors to be able to deal in financial instruments such as hedges (or contracts for differences).
- c Line companies should be required to provide a rebate of Transpower's interconnection charges based on the DG output at the times of regional peak.
- d If the regional DG is aggregated, the Distributor will be sure that if a 'control period' is indicated it can count on at least 60% of the aggregate DG capacity being started. This has considerable value to certain Distributors. The value of lost load should be considered in these calculations and/or the value of delayed network or Transmission investment. (Orion's approach to using DG owned by third parties).
- e DG operators should be required to pay for any DG specific upgrade of the network required to connect to the network. This can be paid 'up front as a lump sum' or amortised over the life of the plant at the DG operators option. (Two way metering, a transformer or line upgrade if necessary to support the DG could be possible inclusions). The line company should be required to obtain three separate quotes for the equipment and installation. In the future, should a third party benefit from the line upgrade paid for by the DG owner, the DG owner should receive some rebate on previously paid costs.
- f Line Company's need to compensate DG operators for Reactive power generated (KVARs).
- g If there is a political desire to increase the uptake of DG, a subsidy may be required. One such incentive would be a \$/MW installed contribution for new DG installations. This is what operates in the UK and underlies their recent sustainability policy.
- h Another form of subsidy for renewables (again which links into the Governments framework on sustainability) is an MRET scheme. That is, a Minimum Renewable Energy Target scheme underpinned by tradable renewable energy certificates (RECs) as seen in a few countries but in particular Australia. The Australian scheme should be modified and improved for New Zealand by having both Thermal and Electrical RECs where a thermal REC is about a third of the value of an electrical REC. This allows a balanced incentive for co-generation versus pure electrical generation, a feature missing in the Australian scheme. Under these schemes, effectively all consumers of electricity pay a very small extra amount which is used to provide a worthwhile (in the region say of 3c/kWh) subsidy to new renewable generation.
- i With the thresholds regime governing Distributors, the issue of cross-subsidisation by Distributors of inefficient generation from monopoly profits should no longer be a potential issue. There is an argument that the arms length separation rules for Distributor owned generation between 5 and 50MW could be relaxed, in particular the need for an independent board for the generation subsidiary which has a negative effect on DG uptake over 5MW by Line companies.

APPENDIX 1: *List of DG installations*

Metered Distributed generation plants, connected to Distribution networks at 33kV or less and < 50MW.

(Note: This schedule is a work in progress at the date of this report)

	Name/Owner	Fuel	Typical Max kW	Location	Approx Load factor (%/yr of installed)	Line Co (Name)	Retailer (Name)	Synchronised to Grid (Y/N)	Metering Type (TOU, ?)
1	Addington (11kV)								
2	Aluminium Diecasting (3.3kV)								
3	Aniwhenua (11kV)	hydro		BoP					
4	Anchor Products(11kV)(Fonterra)	gas	25000?	Hawera		Powerco		Y	
5	Argyle (Trustpower)	hydro	3,800					Y	
6	Arnold/Trustpower (11kV)	hydro	3,000	West Coast SI				Y	
7	Auckland hospital(11kV)	gas		Auckland				Y	
8	Balance Agrinutrients (Amm Urea)	gas	3,000	Kapuni	90%	Powerco		Y	TOU
9	Balance Agrinutrients	gas	3,000	Mt Maunganui	190%	Powerco		Y	
10	Blue Mountain Lumber (11kV)	Biomass/coal		Tapanui-Gore					
11	Brooklyn Wind Turbine (Meridian)	wind	225	Wellington	43%	Vector	Meridian		TOU
12	Brooklyn (Lloyd Wensley)	wind	170	Nelson	80%	Network Tasman	Self	Y	TOU
13	Burwood Hospital(11kV)								
14	ChCh city waste water (11kV)	methane	1,550	ChCh Bromley		Orion			
15	ChCh Hospital campus (11kV)	cogen/		ChCh City		Orion			
16	Crowne Plaza (415V?)	diesel							
17	ChCh wind Turbine (11kV)	wind	500			Orion			
18	Darfield (11kV)								
19	Diesel Marlborough lines (11kV)	diesel		Blenheim	55%	Marlborough Lines			
20	Diesel Marlborough lines (415V?)	diesel		Blenheim		Marlborough Lines			
21	Diesel Network Tasman (11kV)	diesel		Nelson		Nelson Electricity			
22	Dilmans/Trustpower	hydro	3500	West Coast SI	55%		Trustpower		
23	Drysdale Hydro	Water	75	Rangitikei	60%	Powerco	Mighty River	Y	TOU
24	Duffers/Trustpower (11kV)	hydro	500	West Coast SI				Y	
25	Dunedin Energy centre (Meridian)	cogen/					Meridian		
26	Edgecombe/Fonterra	gas		BoP	70%	Aurora	Todd Energy		
27	Falls dam (Pioneer Gen)	hydro							
28	Fox (NZ Energy)	hydro	250						
29	Fraser River (Pioneer Gen)	hydro	2,400	Fox Glacier	50?	West Coast Lines	Trustpower?	Y	TOU
30	Gisbourne (415V?)								
31	Glenorchy 1&2 (Pioneer Gen)	hydro	480						
32	Green Energy	Landfill Gas	1000	Hamilton	95%	WEL			TOU
33	Greenmount	landfill methane	5400	Auckland	80%	Vector			
34	Haast (NZ Energy)	hydro?	1000	Sth Westland	70%		NZ Energy	N	TOU

	Name/Owner	Fuel	Typical Max kW	Location	Approx Load factor (%/yr of installed)	Line Co (Name)	Retailer (Name)	Synchronised to Grid (Y/N)	Metering Type (TOU, ?)
35	Haast Diesel (NZ Energy)	Diesel		Sth Westland	30%		NZ Energy	N	TOU
36	Hau Nui (Genesis)	wind	8,650	Wairarapa		Powerco			
37	Hinemaia (Trustpower)	hydro	7000	Taupo	55%	Unison			
38	Horse Shoe bend								
39	Kawerau	biomass/geo	12000	BoP	90%				
40	Kawerau	biomass/geo	8000	BoP	80%				
41	Kaimai/Trustpower	hydro	45000	BoP	45%	Horizon	Trustpower		
42	Kinierer/Trustpower	hydro	430	west coast SI	100%	Westpower	Trustpower		
43	Kinleith cogen (Genesis)	Biomass/Gas	40,000	Kinleith	90%	Powerco	Trustpower		
44	Kourarau A&B (Genesis)	hydro	1,000	Wairarapa		Powerco	Genesis		
45	Kumara/Trustpower	hydro	6500	west coast SI	55%				
46	Kuratau 1&2 (King Country Energy)	hydro		Taupo		The lines Co	KCE		
47	Leeston (415V7)								
48	Mainpower PV installations	PV	20	Rangiora		Mainpower			
49	Mangapapa Station	hydro	13	Sth Taranaki	90%	Powerco	Genesis	Y	2 way register
50	Mangapehi (Jim Scott)	hydro	2500	Te Kuiti Area	40%	The Lines Co	Mighty River	Y	TOU
51	Mangatangai Dam (Watercare)	hydro	600	South Auckland		Counties Power			
52	Mangorei	hydro	4,500	Taranaki	50%	powerco			
53	Marakopa (Michael Davis)	hydro	700	Te Kuiti Area	40%	The Lines Co	Mighty River	Y	TOU
54	Maruia Springs (Jap. Owned)	hydro	200	Lewis Pass	90%	None - isolated	None	N	TOU
55	Mataura	hydro	800	Southland					
56	Maungatapere			Northland					
57	Mangatawhiri								
58	McKays Creek	hydro	1100	west coast SI	90%				
59	Meg hydro (Pioneer Gen)	hydro	4260						
60	Middleton								
61	Milford Sound	hydro	100	Milford Sound	90%			N	TOU
62	Moerangi								
63	Mokaiti King Country Energy)	hydro	1920			The Lines Co			
64	Mokoia Road			Hawera					
65	Monalto (Trustpower/Elec Ashbthn)	hydro				Elec Ashburton	Trustpower		
66	Monowai (Pioneer Gen)	hydro	6900			Powernet			
67	Motukawa/Trustpower	hydro	4800	Taranaki		Powerco			
68	Ngahere			#REF!					

	Name/Owner	Fuel	Typical Max kW	Location	Approx Load factor (%/yr of installed)	Line Co (Name)	Retailer (Name)	Synchronised to Grid (Y/N)	Metering Type (TOU, ?)
69	Ngawha 1 (Top Energy)	geothermal	10,000	Bay of Islands					
70	Ngawha 2 (2007) (Top En)	geothermal	15,000	Bay of Islands					
71	Omarama (415V?)								
72	Onekaka (Bryan Leyland et al)	hydro	700?	Nelson		Network Tasman	?	Y	TOU
73	Opunake (NZ Energy)	hydro	300	Sth Taranaki	40%	Powerco	Trustpower?	Y	TOU
74	Opua (Opua Dam Ltd&Alpine En)	hydro	7,000			Alpine Energy			
75	Paerau	hydro	10,000	Otago					
76	Patea hydro (Trustpower)	hydro	31,400	Taranaki		Powerco	Trustpower		
77	Patearoa	hydro	2200	Otago					
78	Piriaka (King Country En)	hydro	1550			The Lines Co	KCE		
79	PNCC Awapuni (Energen)	Landfill Gas	1000	Palm. Nth	95%	Powerco	Mighty river	Y	TOU
80	PNCC Hardy St	hydro	30	Palm. Nth	95%	Powerco	Mighty river	Y	TOU
81	PN minihydro	hydro		Palm. Nth					
82	Pukete cogen (Hamilton CC)	methane	2500	Hamilton		WEL		Y	
83	Port Chalmers								
84	Pupu Hydro	hydro	400?	Nelson	80%	Network Tasman	Contact	Y	TOU
85	Raethi (NZ Energy)	hydro	350	Raethi	50%	Powerco	Trustpower?	Y	TOU
86	Rangitaiki (Jim Scott)	hydro	400	Nr Whakatane	50%	Horizons	Trustpower?	Y	TOU
87	Rangitata Diversion Race	hydro							
88	Ravenbourne (Ravensdown Fert)			Dunedin					
89	Ravensdown	exothermic/cogen	4,100	Napier	90%				
90	Ravensdown Homby	Exothermic/cogen		Homby ChCh		Orion			
91	Redvale	landfill methane		Auckland					
92	Rimu Production Station (Swift)	biomass?	1,200			Powerco			
93	Rotokawa(Tahara Nth#22Trust/MRP)	geothermal	32,000	BoP		Unison	Mighty River		
94	Rosedale (MRP)	sewr methane	3,600	Nth Shr- Auckld		Vector	Mighty River		
95	Silverstream								
96	Simeon Quay (415V?)								
97	Sky City Casino (415V)			Auckland					
98	Southbridge (Energy3)	Wind				Orion			
99	Southern Landfill	Landfill Methane		Wellington		Vector			
100	Springston								
101	Tararua windfarm 1 (Trustpower)		31,680	Woodville					
102	Tararua windfarm 2 (Trustpower)		36,300	Woodville					

	Name/Owner	Fuel	Typical Max kW	Location	Approx Load factor (%/yr of installed)	Line Co (Name)	Retailer (Name)	Synchronised to Grid (Y/N)	Metering Type (TOU, ?)
103	Te Awamutu/Fonterra	Gas (tubines)		Te Awamutu					
104	Tarawera Geo 1&2 (BoPE)	Geothermal	6,400			Horizon			
105	Te Rapa (Contact)	Gas (turbine)	45,000	Fonterra/Hamilton					
106	Teviot -6 stations (Pioneer Gen)	hydro	10,530						
107	Totara Rd (PNCC)	hydro	1,000	Palmsom Nth		Powerco	Mighty River	Y	TOU
108	Turitea (PNCC)	hydro	120	Palm. Nth	75%	Powerco	Truspower		
109	Wahapo (former Okarito Forks)	hydro	3,100						
110	Waihi	hydro	5,000	Coromandel		Eastland network			
111	Waihopai	hydro	2,500	West Coast SI					
112	Waipa (Forest Research)	biomass/cogen	3,000	Rotorua					
113	Wairau	hydro	7,200	Marlborough					
114	Wairere Falls (KCE)	hydro	4,560	King Country		The Lines Co	KCE		
115	Wairua (Northpower)	hydro	3,000			Northpower			
116	Waitakaere Dam (Watercare)	hydro	75	Waitakere		Vector			
117	Watercare Mangere	sewr methane	6,800	Mangere					
118	Watercare Waitakere	sewerage gas		Waitakere					
119	Wellington Hospital (Energy fr Indust)	gas/cogen	10,000	Wellington	60%	Vector			
120	Whitford landfill	landfill methane		Auckland					
121	Windflow (Trial machine)	Wind	500	Banks Pen		Orion			
122	Wisper Tech (Stirling Engines)	gas	?	Christchurch					
123	Wye Creek (33kV)(Pioneer Gen)								
124	York Valley Landfill	landfill methane		Nelson		Nelson electricity			
	as percentage of 8,500,000kW		463,188						
			5%						

APPENDIX 2: *People interviewed*

June to August 2006

Purpose: *To discuss definitions, officials position(s) and interviewees perceptions on barriers to entry for DG and the views on alleviating those barriers*

Wellington

#	Organisation	Contact	Position
1	Ministry for Economic Development (MED)	Gareth Wilson Roger Fairclough Janet Humphris	Manager Network Performance Analyst
3	Parliamentary Commissioner for the environment (PCE)	Doug Clover	
3	Major electricity Users Group	Ralph Matthes	CEO
4	Electricity Networks Ass	Alan Jenkins	CEO
5	Biomass Assoc	Brian Cox	CEO
6	Meridian	Grant Smith	Development Mgr
7	Wind Energy Assoc	Murray Kennedy	
8	EECA	Fiona Weightman Selwyn Blackmore	Mgr Elec to GridAnalyst
9	EC	Robert Reilly (acting)	Retail Contracts advisor
11	Business NZ	George Riddell	Manger Energy, environment etc.
11	Smartpower Wgtn	Anne Herrington	Director
12	Transpower	Kerin Devine	GM SO
13	Contact	Ted Montague	
14	Todd Energy	Babu Bahirathan	
15	Energy in Industry	Mike Suggate David Reid	CEO
16			

Auckland

17	Watercare services	Raoul Viljoen	Energy Manager
18	Vector	Simon McKenzie Duncan Head David Kemshall	Developmnt Manager
19	Smartpower Akl	Peter Alderdice	
20	Waste Management	Malcolm Hope	
21	Mighty River Power	Stuart Lush James Moulder Bruce Miller	Development Mgr

Christchurch

22	Orion	Roger Sutton	CEO
23	Mainpower	Andrew Thompson Todd Mead	
24	Christchurch City Council	Leonid Istkovich	Energy Manager

Other

25	Unison	Ken Sutherland	CEO
26*	The Lines co	Brent Norris	Chief Engineer
27*	Eastland Energy	Matt Todd	CEO
28*	Power Co	Ted Broadhurst	
29	WEL networks	Mike Underhill	CEO
30*	Top Energy	Roger de Bray	CEO
31	independent	Martin Post	Independent DG owner/contract installer
32	Mt Campbell Networks Ltd	Lloyd Wensley	Indep. DG owner
33	Clearwater Hydro	Michael Davis	Indep. DG owner

* not interviewed at date of draft report

APPENDIX 3: Regulations summary

The tabulation below sets out regulations proposed by the MED for Distributed Generation connection above 10kW.

<i>Actions required by person wanting to connect distributed generation</i>	<i>Actions required by distributor</i>
1. Makes formal enquiry, in writing, about possible connection.	1. Within required timeframes, provides advice on: network capacity or upgrades that might be needed to connect and receive electricity from the proposed distributed generation; and investigative studies that might be needed.
2. Makes application to connect, completing an application form and forwarding required accompanying documents including any required investigative studies and information to support compliance with the distributor's network safety and connection requirements and an acceptable industry standard.	2. Processes application within required timeframes or advises an extension of time for processing. May seek additional information from the applicant to assist processing. 3. Approves or declines application. 4. Enters into connection contract.
3. Either may export electricity to network upon receipt of approval subject to payment of any connection costs and complying with connection contract; or If application declined, may seek review of decision by an arbitrator. Arbitrator's decision is binding on both parties.	5. If arbitration process is invoked then must cooperate with arbitrator. Arbitrator's decision is binding on both parties.

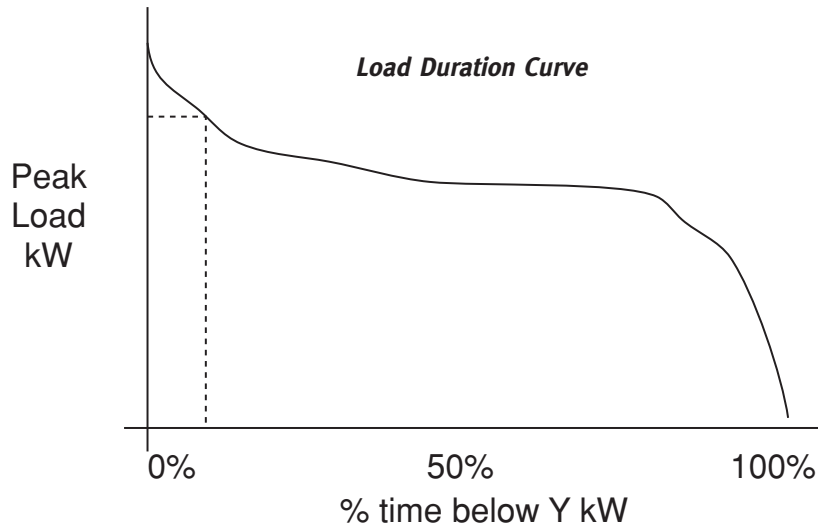
Ref: www.med.govt.nz/electricity/generation-investment/
www.med.govt.nz/templates/StandardSummary_1329.aspx

The Ministry for Economic Development (MED) has recently (Sept 2006) issued the **Electricity Governance (connection of Distributed Generation) regulations 2006** (Regs) for consultation. These specify that if the owner/operator of a potential distributed generation scheme cannot reach a suitable agreement to connect then the following regulations will apply:

	Size	<10kW	10kW-1MW	1-5 MW	>5MW	Regulation clause
1	Distributor to respond to an enquiry in X days	20	20	30	30	15
2	Distributor to respond in X days to a formal application	10	45	60	80	3& Subclause 2
3	Distributor to maintain confidentiality		Yes	Yes	Yes	4, 3
4	Max fee under regs. for formal enquiry process	\$250	10-00kW \$500 100kW-1MW \$1000	\$5000	\$5000	Schedule 4
5	Max fee for application To connect	\$250	\$500	\$5000	\$5000	
6	Additional fees for inspection or observation	Includes: - installation of meters - pre connection inspection - observation of testing perhaps - provision of written authorization to connect				

APPENDIX 4: *Sensitivity analysis on Diesel peak lopping*

Sensitivity of Transmission interconnection charge to DG feasibility



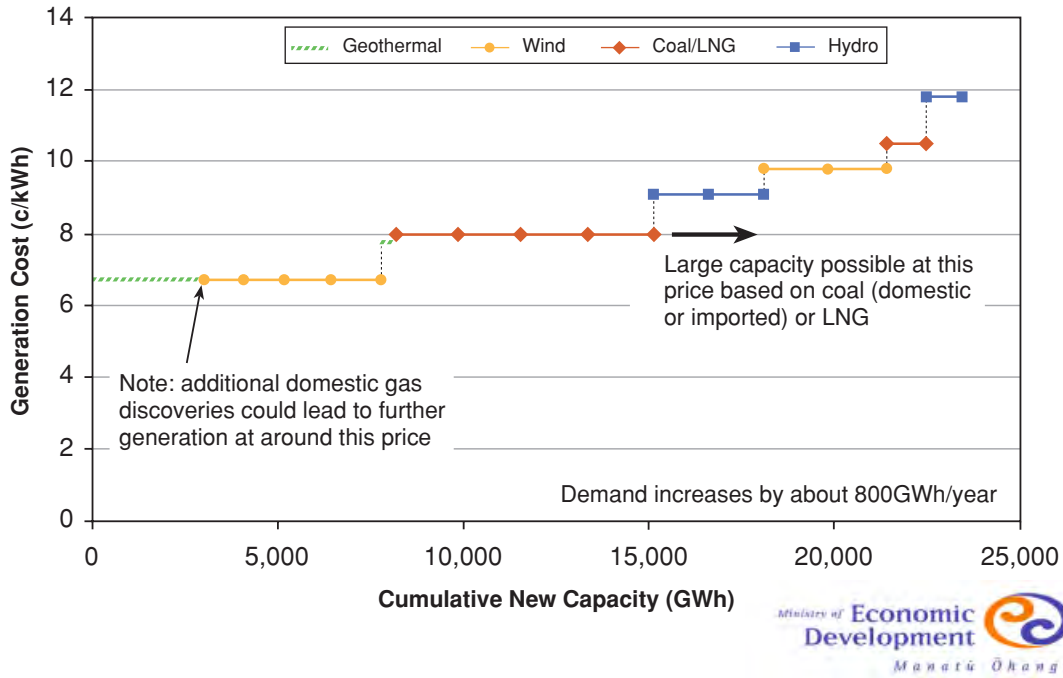
Assume:

- Diesel costs 100c/Litre
- Diesel efficiency 40%
- Assume 330 KW Diesel costs \$660K and is amortised over 20 years at 12%
- Transpower interconnection charge is \$60/kW MD
- MD is average of the 12 highest half hour peaks over last 12 months

% peaks lopped	#/yr of half hour peaks	@ 2hrs/day, # days /yr	Assume 330 KW Diesel generator (KWh generated)	Savings (net costs) K\$/yr
0.5%	88	22 days	14,454	(106)
1.0%	175	44 days	28,908	(144)
1.5%	263	66 days	43,362	(182)
2.0%	350	88 days	57,816	(219)
2.5%	438	110 days	72,270	(258)

APPENDIX 5: *New generation and price curve*

Longer term supply options
Indicative New Plant Generation Costs to 2025



Note: any new Hydro is costed at 9 c/kWh and the graph above suggests that there are at least 21 years of new generation by the time that hydro is built. More importantly there is a thermal generation price point of 8c/kWh. This is the price level to which DG should be able to shadow price to remain economically viable

