BEFORE THE ENVIRONMENT COURT

IN THE MATTER OF	the Resource Management Act 1991
AND	
IN THE MATTER OF	an Appeal under section 120 of the Act
BETWEEN	**ROCH PATRICK SULLIVAN**
	Appellant
AND	**CENTRAL OTAGO DISTRICT COUNCIL**
	First Respondent
AND	**OTAGO REGIONAL COUNCIL**
	Second Respondent
AND	**MERIDIAN ENERGY LIMITED**
	Applicant

STATEMENT OF EVIDENCE OF BRYAN WILLIAM LEYLAND ON BEHALF OF ROCH PATRICK SULLIVAN

1.0 Qualifications and Experience

1.1 My full name is Bryan William Leyland. Until June 2003 I was a Principal of Sinclair Knight Merz, a multi-disciplinary engineering consultancy based in Auckland. I hold the qualification of Master of Science (Power System Design), and I am a Fellow of the Institution of Electrical Engineers (U.K), a Fellow of the Institution of Mechanical Engineers (U.K), a Fellow of the Institution of Professional Engineers (N.Z), I was awarded the Institution of Professional Engineers “Supreme Technical Award” in 2005, the IPENZ “Communicator of the year” in 2001 and the Institution of Electrical Engineers Silver Medal in 2005. I was awarded the Electricity Engineers Association “Meritorious Service Award” in 2004 and was made an Honorary Life Member of the Association in 2005. I was a Director of Vector Limited (New Zealand largest Electricity Distribution Company) from 2003 - 2005,

1.2 I am a Member of the Common Quality Advisory Group of the Electricity Commission. This group advises the Electricity Commission on factors affecting the operation of the New Zealand power system. The group has a special interest in the effect of intermittent generation such as windpower on the operation of the New Zealand power system.

1.3 I was a member of an International Panel of Experts which was formed to identify, investigate and solve major engineering problems at a 2000 MW hydroelectric power station in Iran.

1.4 I am a member of the Expert Advisory Group for the 5900 MW Kalpasar tidal power scheme north of Mumbai in India. If this scheme is built, it will be about 15 times larger than the largest tidal power scheme in operation.

1.5 I have had an active interest in windpower since about 1980, when I helped with the mechanical and electrical aspects of costing a large wind farm using vertical axis wind turbines. I have read widely on the subject and I have a large database of articles describing the cost and performance of existing wind farms and their effects on the operation of the power system.

1.6 I was a member of a group called together by the New Zealand government to give advice regarding the 2003 electricity shortage.

1.7 I provided advice to Meridian Energy on the options for connecting the proposed Project Aqua hydropower scheme to the transmission system. I was able to propose alternatives that would have resulted in a considerable cost reduction.

1.8 On several occasions, I have appeared as an expert witness regarding the state of the New Zealand power system, the need for additional generating capacity and transmission lines and other aspects of power supply and distribution in New Zealand.

1.8 My particular expertise is as an Electrical and Mechanical Engineer in power system operation and optimisation, transmission systems, distributed generation, hydropower generation, thermal power stations, cogeneration, and power system design and protection. From 1992 until 2003 I was responsible for biannual reviews of electricity supply and demand in New Zealand. Those documents are still the only publicly available comprehensive and independent review.

1.9 Over the last fifteen years I have made many presentations at conferences and I have written articles for newspapers on power planning, the problems faced by the New Zealand electricity system, the risk of shortages resulting from insufficient generating capacity and the risk of blackouts resulting from an overloaded transmission system. On many occasions I have been interviewed for radio and television news programmes on these subjects.

1.10 I was responsible for the overall concept and for the detailed design, procurement and commissioning of mechanical and electrical equipment for a a 930 kW small hydropower scheme in Golden Bay. I am now responsible for its day-to-day operation. My wife and I are 25%

shareholders in the scheme. Operating the station requires that I monitor electricity prices and electricity demands on a more than daily basis. I am, therefore, very familiar with the price spikes that appear on the system when hydropower storage lake levels are low or when there are problems on the system.

2.0 Engagement

2.1 I have been engaged by the Appellant, Roch Patrick Sullivan to express my opinion on the likely cost of generating electricity from Project Hayes and to compare that to the likely cost of generating others forms of electricity.

2.2 I confirm that I have read, and familiar with, the Code of Conduct for Expert Witnesses in the Environment Court set out in Consolidated Practice Note 2006.

2.3 In preparing this statement I have reviewed and had regard to, among other material:

(a) The Briefs of Evidence of Guy Waipara, Timothy George and John Geadlow;

(b) Report by PB Power entitled "Electricity Generation Database statement of opportunities updated 2006";

(c) Energy Central Newsletter (http://energycentral.com);

(d) Report by Cambridge Energy Research Associates (29/5/08);

(e) The System Operator's monthly report to the Electricity Commission of May 08;

(f) Summary of Findings NZ wind integration study April 2008 by Strbac et al and Meridian Energy

(g) National Winter Group 2008 Initial Report 7 December 2007 published by Transpower

(h) The Centralised Dataset DVD published by the Electricity Commission

3.0 Cost of Generation

3.1 The cost of generation from a wind farm is made up of a number of component costs.

Capital Cost

3.2 The most important cost is the capital cost of the wind farm itself. The capital cost can be broken down into preliminary costs, the overseas costs of manufacture, shipping the turbines and associated equipment, and on-site costs such as preliminary studies, civil works, roading and cabling between the individual turbines and the central point where the wind farm is connected to the grid. These costs determine the capital expenditure needed to build a wind farm.

3.3 I have made use of the cost estimates given in a report by PB Power entitled "Electricity Generation Database -- statement of opportunities updated 2006"[1]. On page 25 PB Power state that their estimate of the overseas element of the cost of a typical wind farm is $NZ 2200/kW. They also estimate that the New Zealand component of the cost is between $300 and $400/kW. This gives a total installed cost of between $2500 and $2600/kW.

3.4 I have checked this estimate against recent orders that have been placed in various countries and other reports on the costs of windfarms as reported by Energy Central,[2]. The following are recent costs of overseas wind farm developments:

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[1] [1]Prepared for the Electricity Commission and dated October 2006

[2] "Energy Central" Industry Newsletter(http//energycentral.com)

3.4.1 Suwalco and Tychowo in Poland (21/4/08)

An order valued at approximately Euro100 million was placed with Siemens for 33 turbines with a total capacity of 76 MW. This is equivalent to a $US 2000/kW. ($NZ 2660) This covers the generating plant only so the final costs would be close to $NZ 3000/kW.

3.4.2 Ashtabula Wind Center in North Dakota USA (30/4/08)

The expected cost of the 48 MW project is "more than $ 121 million". This equates to $US 2520/kW or $NZ 3300.

3.4.3 New Richmond and St Valentine in Quebec, Canada (5/5/08)

The expected cost of the 66 MW new Richmond project is $190 million. This equates to $US 2880/kW or $NZ 3800.The expected cost of the 50 MW St Valentin wind project as $160 million. This equates to $US 3200/kW or $NZ 4200/kW.

3.4.4 Pampa Wind project in the Texas panhandle, USA (15/5/08)

The expected cost of the 1,000 MW project is $2 billion. This equates to $US 2720/kW or $NZ 3600/kW. An order has been placed with General Electric for 667 1.5 MW wind turbines.

3.4.5 Report by Cambridge Energy Research Associates (29/5/08)

This is a report on wind power in Europe. It states that "capital costs could rise by 20% from $US 3555 to $US 4342/kW in the next several years".

3.4.6 Hallett Wind Farm AGL Energy Ltd - (13/6/08)

At a reported cost of $A236 million 95MW this wind farm in South Australia (45 turbines) equates to $A 2484/kW. ($NZ 3000)

3.5 In my opinion these reports are typical of the current state of the international market and that they indicate that the $NZ 2500 -- 2600/kW estimated by PB Power in 2006 should now be increased to at least $3000/kW. (The average of the above costs is $3440.) Given that New Zealand is remote from the manufacturers, and $3000/kW is at the lower end of the overseas costs, a cost of $3500/kW may well be realistic. To cover the range, I have used $3000/kW and $3500/kW in my calculations.

Maintenance costs

3.6 The next major cost is the operation and maintenance cost. On page 20 of the PB Power report it states that "annual operation and maintenance costs are in the range of $32 to $52/kW in years 1 to 5, $22 to $44/kW in years 2-12, and $44 to $75/kW in years 8-20." I have used the average of these figures in my calculations and, because the periods given overlapped, I have assumed that the periods should have been 1-5, 6-12, and 15-20 years respectively. At $42/kW (the average of 32 and 52) the 630 MW Hayes wind farm would have an operation and maintenance cost of $26.5 million per annum.

Frequency keeping costs

3.7 There are costs associated with frequency keeping. The power system must be managed within a narrow band of the Grid frequency (nominally 50 Hz). If the frequency deviates too far from 50Hz the whole system will collapse. Frequency keeping ensures that the amount of electricity generated exactly matches the load on a minute by minute basis. Frequency keeping requires that some stations are constantly changing output to match fluctuations in the load or, for instance, the fluctuating output of wind farms.

3.8 Wind power stations impose additional frequency keeping costs on the power system that are greater than, for instance, from hydropower stations. From the point of view of system operation, the major problems with wind power are that it is unpredictable and that it can fluctuate very rapidly. These rapid fluctuations means that with wind power connected to the system, frequency keeping becomes more difficult and more expensive. At the moment, frequency keeping plant operates to manage fluctuations in the range of +/- 50 MW. Experience with integrating the output of the Manawatu wind farm shows that wind generation has increased the need for -- and hence the cost of - system frequency keeping.

3.9 The unpredictability of wind generation means that the system operator cannot be confident of the output of wind farms more than an hour so into the future. Because it takes longer than one hour to bring one of the large steam turbines at Huntly coal-fired power station from "hot standby" (that is stopped but warmed up and ready to start) to full load, then very often, the system operator will be forced to keep thermal and hydro plant connected to the system and running at less than full load because of the need to have generating capacity available in case the wind drops or the expected wind does not eventuate. This is inefficient and expensive. The costs fall on the consumers.

3.10 Although these costs are real, it is difficult to determine them with accuracy so I have allowed for them at $5 million pa. They are most unlikely to be lower than this. Over the last 12 months, the monthly frequency keeping costs have ranged between $2 and $19 million[3]. (From the System Operator's monthly report to the Electricity Commission of May 08.)

[3] From the System Operator's monthly report to the Electricity Commission of May 08

4.0 **Meeting the Demand for electrical energy**

4.1 When determining the need for new generation, sufficient electrical energy must be available to meet the forecast power demand for electricity over the critical autumn-winter period in a dry hydro year when hydro-inflows are 15 – 20% lower than average and the power demand is at its maximum. The autumn and winters of 1998, 2001, 2006 and 2008 are typical examples. If insufficient energy is available, the lake levels will fall, prices will rise dramatically and an electricity savings campaign may be needed to minimise or avoid the risk of power cuts.

4.2 Wind farms generate electrical energy whenever the wind is blowing. If the energy is not needed at the time that it is generated, it can often be stored in hydro storage lakes. But there are important caveats to this because, as I show below, on average, the output from the wind farms in New Zealand is about 9% below annual average output during the March to August period when lake levels are most likely to be low and there is a risk of a serious shortage. The output of the wind farms is at its highest level during the spring time. This is when the snow melts and supplies additional water into the hydro lakes. As a result of the snow melt and spring rains, the prices are often very low in the late spring and early summer thus demonstrating that any extra electricity generated during this period is of less value to our power system.

4.3 The hydro storage available to the New Zealand power system amounts to about six weeks electricity demand. Other countries that have a high proportion of hydropower such as Tasmania and Norway can store up to three years electricity demand in hydropower lakes. So the fact that wind power is at maximum during the spring time means that it will put an increased demand on New Zealand's limited hydropower storage. As a result, if Project Hayes is built, there is likely to be increased hydro spill when we get a wet and windy spring. This will mean that a proportion of the energy generated by the wind farms will be lost. This, and the fact that the surplus energy available will drive power prices down, makes Project Hayes less economically attractive than it would be if its output was at its highest during autumn and early winter.

4.4 I have analysed the publicly available data[4] recording monthly average output of all the North Island wind farms since the year 2000. For each month, I have calculated the capacity factor (the capacity factor is the ratio of the average MW output during a month to the installed capacity of the wind farms.) The plotted data it is shown in Exhibit 1. The chart shows that, during the months of March to August, when the hydro storage is most often at low levels, the output of the wind farms was below the long-term average capacity factor of 0.39, in all months except June. The average monthly output during the period from March to August is found to be 91.4% of the average annual output. That is to say, the output of the wind farms is roughly 9% below the long term average output during this important period. As a dry hydro year is reckoned to be one where the hydro power output is 15% - 20% below normal, the simultaneous 9% reduction in output from wind is quite significant. This data does not include the wind farms in the South Island. However, the data from White Hills wind farm for the first five months of this year, indicates that, if anything, the drop in output during the late summer in a dry year is even more pronounced.

4.5 I have also investigated the output of the North Island wind farms with an installed capacity of 180 MW during June and July 2007 when the system demand was above 5500 MW. The analysis was carried out using publicly available data. Exhibit 2 shows the results of this analysis expressed as a percentage of the time that the output of the wind farm was between 0 - 10 MW, 10 - 30 MW, 30 - 50 MW, and so on. This analysis shows that the output of the wind farms was below 10 MW for 25% of the time, and it was between 10 MW and 30 MW 12% of the time. Putting it another way, for 37% of the time the output was less than

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4 Centralised Dataset DVD April 2008 from Electricity Commission

30 MW. 30 MW represents 17% of the 180 MW installed capacity of the wind farms. From this I conclude that, during the critical winter peak demand period in 2007, it would have been most unwise to rely on having more than 10 MW of wind power available during a peak demand period.

5.0 Capacity during system peak demand periods

5.1 It is essential to have sufficient generation capacity (plus a reasonable reserve) available at times of peak demand on the New Zealand electricity system. On a typical winter day, the minimum load on the system will be about 4000 MW while the peak demand will be in excess of 6000 MW. At the beginning of each day, the system operator must develop a schedule for generation that will ensure that the system can meet peak demand. When doing this the system operator can only schedule plant that is 100% sure to be available.

5.2 Many investigations have been carried out -- such as the one by Strabac et al - to try and estimate the extent to which the system operator can rely on windpower. Unfortunately, recent evidence from the actual operation of the New Zealand power system shows that these studies have tended to overestimate the windpower capacity that will be available during system peaks.

5.3 Transpower's systems operations manager, Kieran Devine has publicly acknowledged wind power's shortcomings during system peak demand periods. I refer to an article in the Taranaki Daily News on Wednesday, 11 June 2008. about a proposed wind farm in Taranaki. The relevant article reads as follows:

> *"Transpower system operations manager Kieran Devine says the country's three major farms, clustered around the Manawatu Gorge, supplied less than one per cent of their capacity during peak load periods during the past three winters, 2005-07. The highest peaks occurred in the North Island on cold, still weekday evenings, for three to four hours, starting between 5.30pm and 6.30pm. This is when the electricity price also hits a peak. There was not enough*

wind blowing at those times to turn the blades fast enough.

The apparently flawed peak winter performance of existing wind farms has come out of the first three years of a 10-year wind generation investigation project. Mr Devine says turbines on the Manawatu wind farms all behaved similarly, running up and down the generation scale together. "Either there was insufficient wind at that time, or the current farms are all in the wrong locations and there's not enough wind system diversity," he says. "We have real concerns about the large amount of wind generation planned in the lower North Island, because the preliminary information is that they will all have very similar characteristics to the Manawatu farms and that won't help with winter peaks. We'd prefer they were spread around so that when one's up others will be down and it would balance itself out. "Fortunately, the wind characteristics at the new White Hill farm (29 turbines, near Dunedin) appear to be different to Manawatu."

"*He says power planners are just beginning to discover what wind is all about because the detail needed for wind farm management has never been required in the past. "In the long term, wind is very reliable but in short term you can never count on it being there when you need it in forward forecasting."*

5.4 I telephoned Kieran Devine on 11th June 2008 and he confirmed to me that the article in the Taranaki Daily News was not inaccurate. He also told me that the actual contribution to peak demand from the Manawatu wind farms in the years 2005, 2006 and 2007 was five, eight and zero MW respectively. He pointed out that these three wind farms were located close together and that there was a reasonable possibility that the figure would be higher if there were wind farms distributed around the country.

5.5 This is confirmed by the attached graph (exhibit 9) from the National winter group initial report Dec 2008[5]. It shows that when determining the generating plant that will be available during critical peak demand periods Transpower assume that no wind generation will be available.

5.6 From 1 January to 3 July 2008, a period when New Zealand needed all the generating capacity it could get, the two (Meridian owned) wind

[5] 'National Winter Group Initial Report 2008 fro Transpower

farms for which public data is available, generated less than their long term average generation. In fact, for 20% of the time their output was less than 40% of the total installed capacity. For 20% of the time the total output was above 51% of installed capacity. During this period, the average capacity factor of White Hills was 0.31, of Te Apiti, 0.34. In an average year, the capacity factor of Te Apiti is, I believe, in excess of 0.4. This is a strong indication that, in dry hydro years, the output of wind farms will also be lower than normal. All this means that their contribution to supplying energy and to supplying electricity at times of peak demand was less than would be achieved by conventional stations.

5.7 I have obtained the publicly available figures[6] for generation at Meridian's Te Apiti wind farm in the Manawatu and at the White Hills wind farm in Southland for the period from 1 January to 3 June 2008. These figures are for average daily output and hence the fluctuations that occur within a day have been averaged out. So the real situation is more extreme than indicated by the daily averaged data. The three charts that I have derived from these figures are shown as exhibits 3, 4 and 5.

5.8 Exhibit 3 shows the average daily generation at Te Apiti. It is clear that the output fluctuates considerably from day to day and that from the middle of March to the end of the period, the output was relatively low. If the station had been operating at its annual average capacity factor, the average output would have been in the vicinity of 40 MW. It was much lower than this. It is a reasonable assumption that the low average wind power output is related to the La Nina weather which, in turn, is a factor in the low rainfall. Further investigation may be needed to make sure that this is -- or is not -- typical of most dry years.

5.9 From the data, I was able to calculate the percentage of time that the

[6] Centralised Dataset from Electricity Commission

output of the wind farm was above a certain level. This is shown in the text on the diagram. It shows that the output is above 71% of installed capacity for only 10% of the time and it is above 4% of installed capacity for 90% of the time and above 11% capacity for 80% of the time. Simply put, it means that the wind farm seldom operated at anything near its maximum capacity. At the other end of the scale, there is high confidence that the output would be at least 4% of installed capacity. It is relevant to compare this with a conventional power station where there is high confidence (i.e. 95% or more) that it can operate at its maximum capacity whenever required. I also calculated the capacity factor during the 1 January – 3 June period. It was 0.34 which is 15% less than the 0.4 capacity factor which, I understand, is the long term average for this wind farm. This indicates – but does not prove – that the output will be unusually low during a dry hydro year.

5.10 Exhibit 4 shows the same data for White Hills wind farm. The characteristics are similar to Te Apiti except that the output is above 2.5%, rather than 4%, for 90% of the time. There is, therefore, little confidence that it will be generating a substantial amount of power during a peak demand period in the future. During this period the capacity factor was 0.31 which is 16% below the 0.37 capacity factor that, I understand, is expected for this wind farm.

5.11 Exhibit 5 illustrates the effect of combining the output of the two wind farms. I have done this to assess the extent to which the two farms support each other. If two wind farms are geographically separated they experience different wind conditions. If it often happens that the wind is blowing at one farm when it is not at the other, then the fluctuations in output will tend to balance out. The chart shows that this has happened to some extent but there is still a considerable amount of fluctuation. The output that is always available 90% of the time has increased to 9% of total installed capacity. The output that is available for 100% of the time is only 2%. Looking at maximum output, the data shows that the output is above 60% of installed capacity for only 10% of the time and never exceeds 83%. This means that, for all practical purposes, the output of the two wind farms together could be said to be 89 MW (60% of 148.8 MW) rather than the installed capacity of 148.8 MW. To put this in context, it means that, if New Zealand's load growth is, as claimed, 150 MW per year, more than 250 MW of wind plus some backup capacity would need to be installed to meet this load growth. This is not widely realised. It appears to be generally believed that a 150 MW wind farm is sufficient to meet a load growth of 150 MW. Clearly, this is not the case.

5.12 The above and Exhibit 2 demonstrate that the System Operator's policy of assuming that there will be no output from wind farms when scheduling generation for the day, is realistic and prudent.

5.13 I am confident that, even with widely distributed windpower, it would be risky to assume that as much as 20% of the capacity would be available during system peak demand times. Assuming that 10% would be available would be less risky because it would happen less often and, if the system operator was wrong, the chances are that there would be sufficient capacity available on the system to substitute for the missing 10%.

5.14 It is often claimed that the reserve capacity held to cover the loss of a large generating set or the Direct Current Link can also be used to back up wind power if, during the peak demand period, the output of the wind farms is low. As reserve capacity is normally not less than 400 MW, this proposition appears to be quite credible. But it does not stand up to close examination. If, for example, the effective capacity of all the wind farms in New Zealand is 400 MW, and if, as already demonstrated, the actual output of the wind farms is less than this for 90% of the time, then the wind farms would be "using up" some of the system reserve capacity 90% of the time. For about 10% of the time, the wind farm would be using up at least 90% of the system reserve. From my knowledge of system operation, I am confident that a prudent System Operator would regard this as unacceptable. So the conclusion is that if the system reserve capacity is used to backup the wind farm, it can only cover a relatively small percentage of the wind farm capacity. The inescapable conclusion is that a substantial amount of generating capacity will have to be allocated purely to cover the risk associated with the variability and unpredictability of the output of the wind farms during system peak demand periods. The alternative is to assume that the wind farms will provide only a small contribution to meeting peak demands and treat them purely as a source of electrical energy that, when it is available, would reduce the amount of generation at fossil fuel stations and, at times, cause additional spell at the hydropower stations. If this is done, then the only value of windpower (apart from small contribution to peak demand) will be saving in fossil fuels. In my opinion, this would mean that the benefit of the wind farms to the power system would be in the range of 3 cents to 6 cents/kWh of the electricity potentially able to generated by the wind farms. The lower figure represents an allowance for the fact that quite a high proportion of the wind energy may be lost as hydro spill or as a result of constraining wind power generation.

5.19 As explained above, during a dry year, those hydro stations with very limited storage will have limited ability to back up a drop in windpower for more than a few hours. Some of these hydropower stations may not even have sufficient water to allow them to run at maximum output. Also, many of our hydro stations have restrictions on the rate of change of downstream flow which seriously limits their ability to increase output rapidly if the wind drops suddenly. These two factors mean that the ability of hydro stations to support wind during critical peak demand periods in a dry year is quite limited when compared to a normal year.

6.0 Back up Generation

6.1 Taking the foregoing into account, I believe that it is reasonable – and, if anything, generous -- to assume that no more than 10% (~60 MW) of the installed capacity of Project Hayes can be allocated to meeting system peak demand and that, for all practical purposes, the maximum effective capacity of the Hayes wind farm during a dry hydro year (that is critical for planning and operation of the New Zealand power system) is no more than 500 MW. That, in turn, means that 440 MW of backup will be needed if the wind farm is to be compared directly with a 500 MW thermal or geothermal power station (or with a hydro system that includes sufficient reserve thermal capacity to make up for the 15% reduced output in a dry year.) In my opinion, of the 440 MW of backup that is needed, about 90 MW can be probably be provided by the power system reserves during critical peak demand periods and, therefore, 350 MW of additional backup capacity will be needed.

6.2 This backup capacity must be very flexible, must be able to start very quickly and must be able to operate over a wide range of loads. For this duty, an open cycle gas turbine is ideal. Unfortunately, they are relatively expensive ($ 1100/kW according to PB Power) and they are relatively inefficient compared to a combined cycle gas turbine CCGT) (which has a boiler and a steam turbine associated with a conventional gas turbine. Unfortunately, a CCGT is much less flexible and hence it cannot be used to back up wind). Gas turbines are limited to burning gas or diesel fuel. Diesel fuel is very expensive and, because gas suppliers want to supply gas continuously rather than intermittently, the gas supply for a gas turbine used intermittently and unpredictably for backup would also be expensive. An alternative would be hydro-pumped storage but as I I know from other studies I have carried out that this would be equally expensive, I have not considered it further.

6.3 To estimate the fuel consumption of the gas turbines I have assumed that the gas turbine backup capacity will only be called on during June, July and August winter months when all available hydropower capacity is often needed to meet system demand. During other times, I have assumed that hydropower would be able to provide back up. Under this assumption a gas turbine backup would need to operate less often than if it were the sole backup for the windpower stations. For that reason, I have assumed in my calculations that it will be in operation only 10% of the time. I have further assumed that the cost of generation will be

$0.20/kWh. According to my calculations the need for this amount of thermal generation will mean that the wind farm is only 85% renewable.

6.4 The owner will expect a reasonable return on the capital involved and in my calculations I have assumed that they would require a return of 10%. I think this is a reasonable rate of return given that life of the wind turbines is unlikely to be more than 20 years (nobody knows what the life is because no wind farm using modern large machines have been in service for more than four or five years.) It is also the life used in the PB report referred to below.

7.0 Cost Comparison

7.1 I now compare the cost of electricity generated by Project Hayes with the cost of electricity from thermal and hydro power stations.

7.2 One of the appendices to the PB Power report quoted above sets out their estimates of the long run marginal cost and short run marginal costs of the new thermal power stations. This is attached as Exhibit 6. I will use the long run marginal cost because it is directly equivalent to the cost I have already calculated for Project Hayes. The highest cost PB Power have calculated is 10c/kWh for an open cycle gas turbine running on natural gas in Auckland.

7.3 Other costs are 8.2 c/kWh for a power station with 400 MW units burning Southland lignite. A 150 MW unit burning Buller coal would generate at an estimated cost of 9 cents/kWh. (These costs are from the PB Power report)

7.4 PB Power have estimated the cost of geothermal generation. For the Kawerau station, which is about to be commissioned, the estimate is just over 7 cents/kWh. For the Tauhara station, the cost estimate is 8.9 cents/kWh.

7.5 PB Power have also calculated the cost of hydro generation. Most of the schemes they have costed at less than \$3000/kW. To give a fair comparison, this needs to be compared to the cost of Project Hayes together with the 350 MW of backup capacity If we assume that the effective output of Project Hayes is 500 MW and the cost is \$2,275 million, the equivalent cost is \$4550/kW - 50% more than the cost of the hydro station. A 500 MW hydro station would operate at an annual capacity factor of at least 50% so it will generate about 2,200 GWh pa - almost exactly the same as Project Hayes together with its backup generation. The information above was entered into a spreadsheet to calculate the cost of generation from the wind farm, to calculate the cost of backup supply and to calculate a CO2 tax that would be needed to bring the cost of generation from the thermal stations equal to the cost of generation from the wind farm. The spreadsheet is shown in Exhibits 7 and 8.

7.6 The conclusions from this spreadsheet are:

7.6.1 At the point of connection to the grid, electricity from the wind farm costs 12.5 c/kWh if the wind farm costs \$3000/kW and 14.3 c/kWh at \$3500/kW.

7.6.2 When reasonable estimates are made of the cost of a backup generation, transmission - at a conservative \$ 100 million - and system operation costs of \$5 million per annum, the overall cost of generation from the wind farm (the cost that the electricity consumers would see) is 15c/kWh and 16.5 c/kWh for the two capital costs above.

7.6.3 If the backup generation is provided by open cycle gas turbines, they would generate 307 GWh. and and, as a result, the wind farm output will be only 85% renewable energy. The gas turbines will emit 184,000 tonnes of carbon dioxide each year. If this is valued at \$50/tonne, the CO2 tax payable would be \$9 million per annum. This increases the cost of generation but I have not included in my calculations.

7.6.4 Calculations to determine the break even CO_2 tax show that, compared to the alternative lignite, coal and gas-fired generation, the annual cost of wind power is higher by $160 million, $141 million and $165 million respectively. In percentage terms power from Project Hayes is 45%, 39% and 46% more expensive than the cost of this thermal generation. The CO_2 tax necessary for break even between thermal and Project Hayes is $68, $80, and $192 per tonne respectively.

7.7 I conclude that if Project Hayes proceeds it generates very expensive electricity compared to the alternatives available to Meridian.

8.0 Conclusions:

8.1 The cost estimated by Meridian is well below costs established by contracts for similar wind farms that have been placed overseas in the last few months. Based on these current costs of construction, the total cost of Project Hayes would be between $3000/MW ($1.89bn) and $3500/MW ($2.2bn) .

8.2 The cost of the electricity generated by the wind farm will be in the range of 12.6 to 14.3 c/kWh at the point of connection to the grid and approximately 15 to 16.5 c/kWh when system related costs such as the need for backup and additional frequency management, are taken into account.

8.3 Other sources such as hydropower, geothermal and coal and gas-fired stations can generate electricity at approximately half the cost of Project Hayes.

8.4 To make the cost of electricity from a lignite fired power station comparable with Project Hayes, a carbon dioxide (CO_2) tax of at least \$68/tonne of CO_2 is needed.

8.5 To make the cost of electricity from a gas fired power station comparable with Project Hayes, a CO_2 tax of more than \$190/tonne is needed.

8.6 Project Hayes' contribution to supplying energy and to supplying peak demand during a dry year will be less than in a normal year and much less than would be achieved by conventional stations.

8.7 If the 630 MW Project Hayes was backed up by 350 MW of open cycle gas turbines it would be roughly equivalent to a conventional power station rated at 500 MW. Based on a 500 MW capacity, the equivalent cost of Project Hayes plus backup is \$4550/kW. This is well above the current cost for a hydro station (about \$3000/kW) that would generate about the same amount of energy.

8.8 In my expert opinion, the electricity consumers of New Zealand would be much better off if Meridian abandoned this project and, instead, built an equivalent power station based on hydropower, geothermal energy, natural gas or coal because this would save the country – and the consumers – about \$160 million p.a.

Bryan William Leyland

19 June 2008

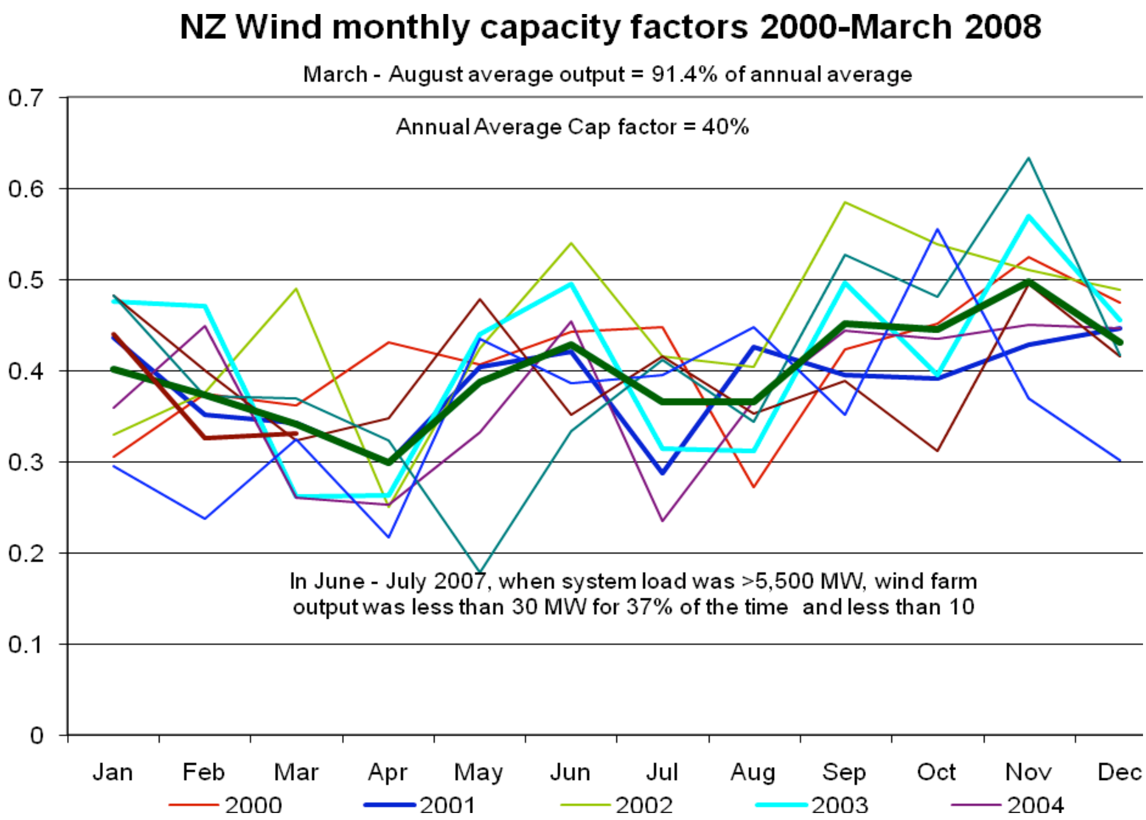

Exhibit 1

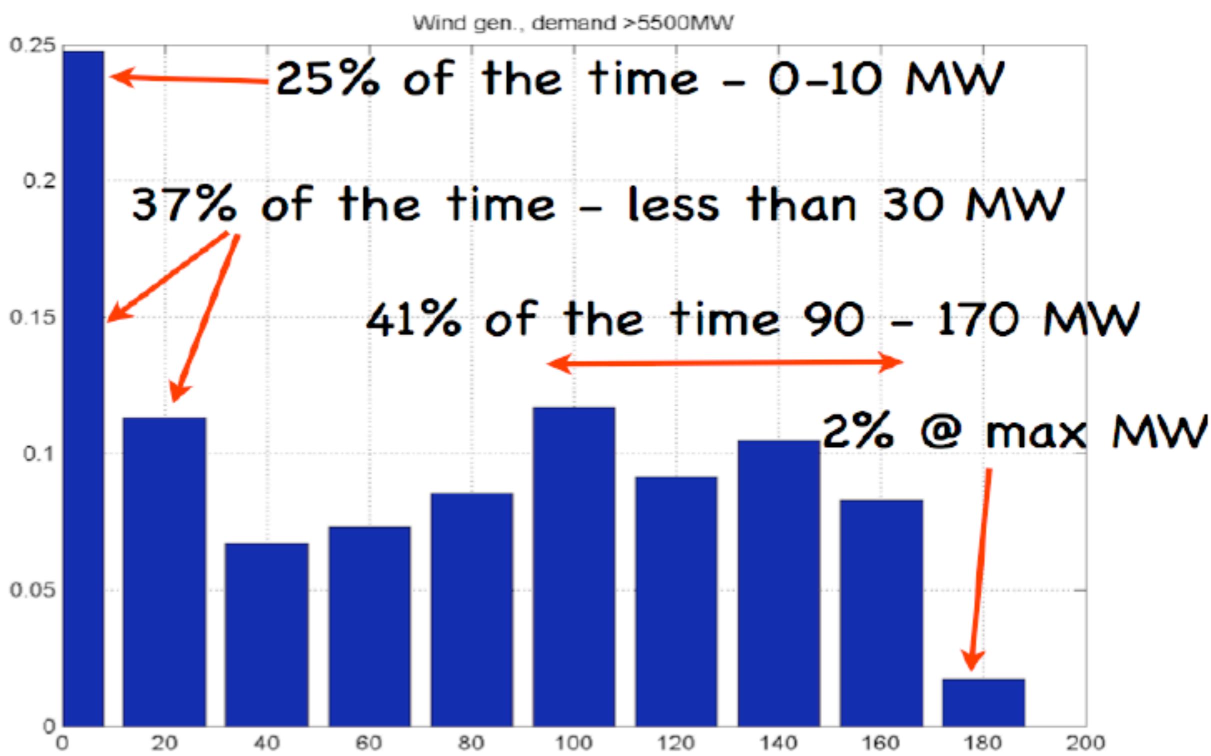

Exhibit 2

Te Apiti daily generation (MW) 1 Jan-3 June 08

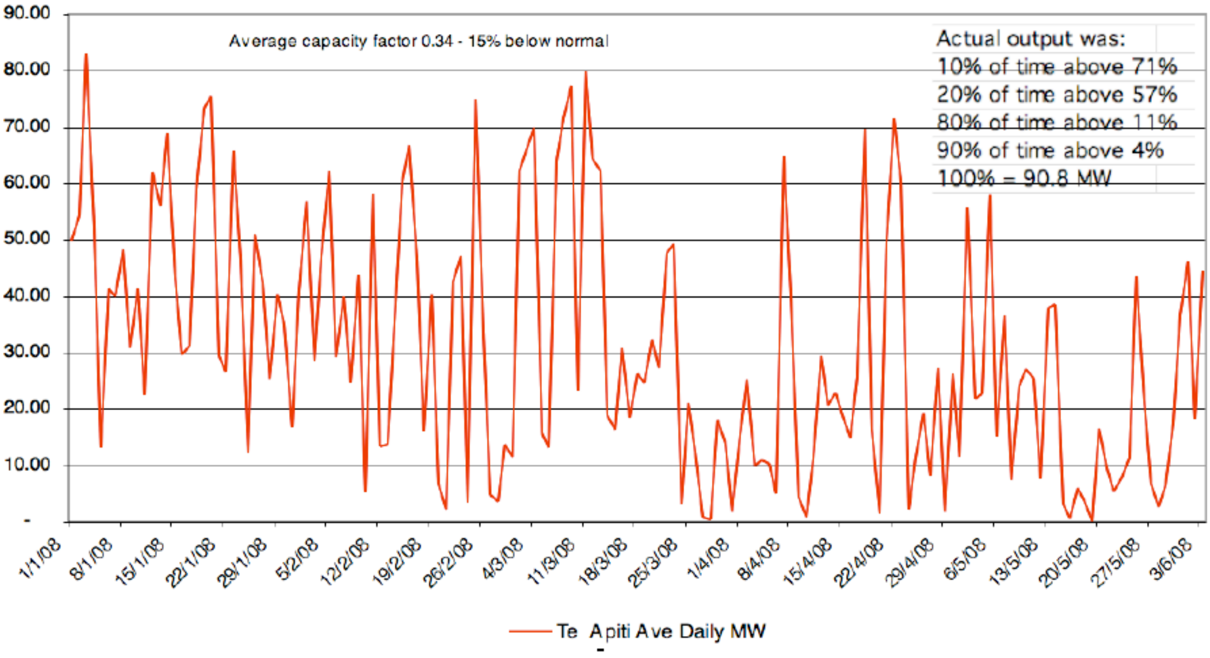

Exhibit 3

White Hills daily generation 1 Jan - 3 June 08

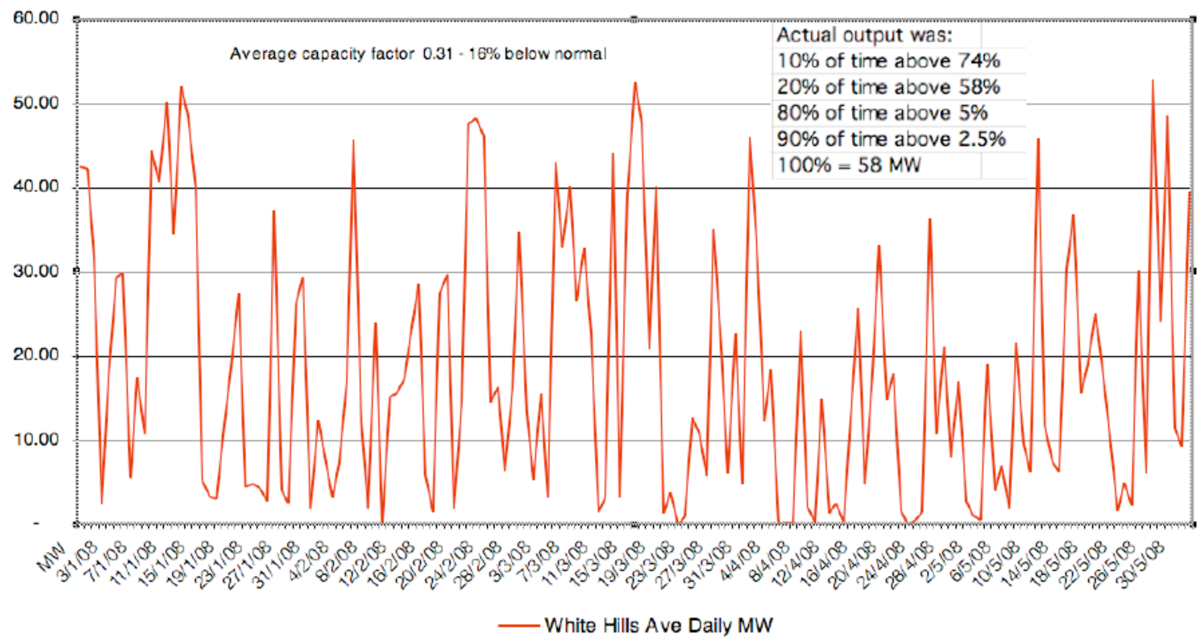

Exhibit 4

Te Apiti and White Hills total generation 1 Jan - 3 June 08

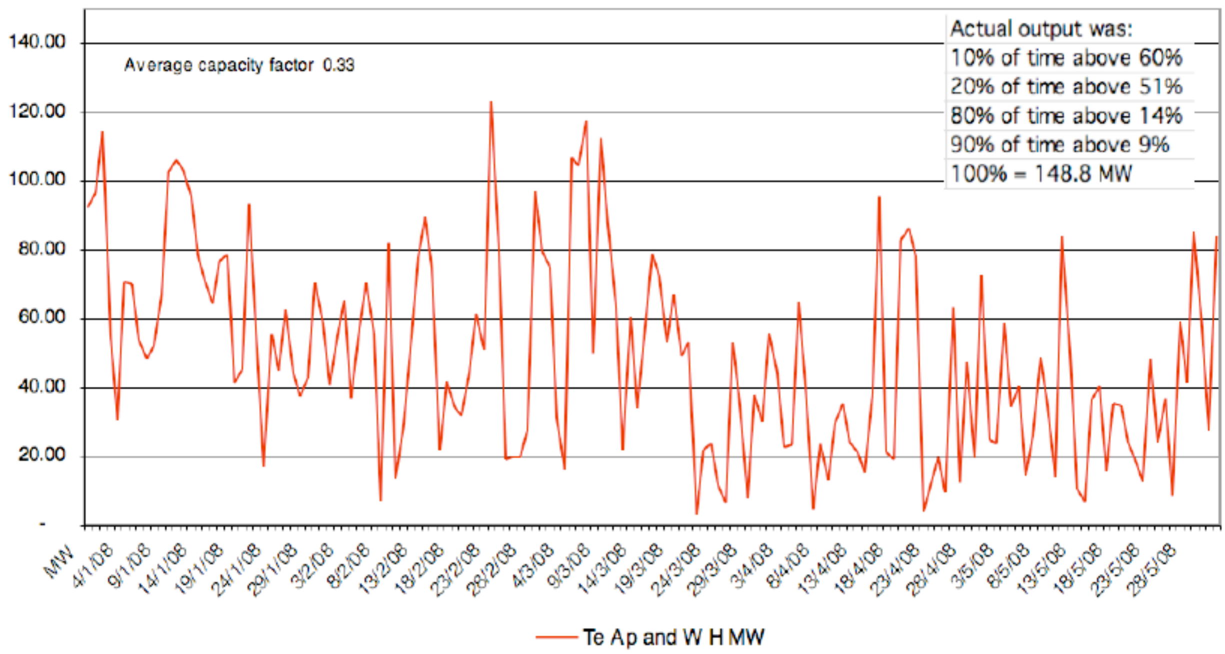

Exhibit 5

Carbon tax Calcs	Lignite	Coal	Gas CCGT	
Annual generation	2357	2357	2357	GWh
CO2 from thermal station	1.00	0.75	0.365	kg/kWh
CO2 from thermal station	2,357,000	1,767,750	860,305	Tonnes
Cost of power from thermal (PB report)	8.2	9	8	c/kWh
Cost of power from thermal	$193	$212	188.56	$m pa
Cost of power from wind at 15 c/kWh	$354	$354	$354	$m pa
Premium paid for wind	$160	$141	$165	$m pa
Carbon price for breakeven	**68**	**80**	**192**	**$/tonne**

Exhibit 7

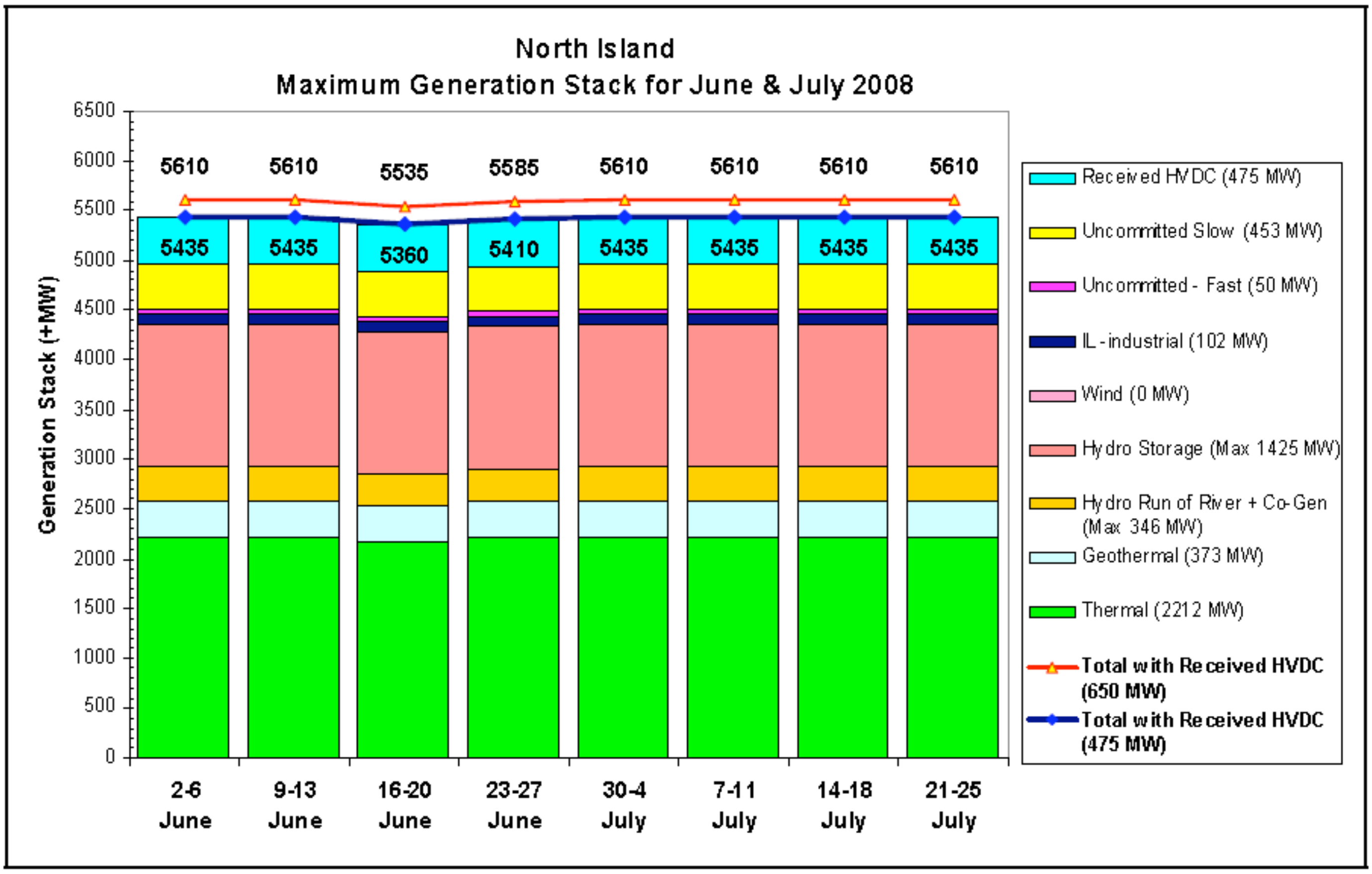
North Island
Maximum Generation Stack for June & July 2008
Generation Stack (+MW)
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
5610
5610
5535
5585
5610
5610
5610
5610
5435
5435
5360
5410
5435
5435
5435
5435
2-6 June
9-13 June
16-20 June
23-27 June
30-4 July
7-11 July
14-18 July
21-25 July
Received HVDC (475 MW)
Uncommitted Slow (453 MW)
Uncommitted - Fast (50 MW)
IL - industrial (102 MW)
Wind (0 MW)
Hydro Storage (Max 1425 MW)
Hydro Run of River + Co-Gen (Max 346 MW)
Geothermal (373 MW)
Thermal (2212 MW)
Total with Received HVDC (650 MW)
Total with Received HVDC (475 MW)

Exhibit 9

Statement of Opportunities Update 2006

LRMC of Proposed New Thermal Power Stations

Plant Name	Owner	Location	Plant Type	Island	Fuel Type	Capacity MW	Heat Rate GJ/GWh (HHV)	Fuel Cost $/GJ	Transport & Capacity Charge $/GJ	Capital Cost $/kW	O&M $/kW (6)	Capital Cost $'000	LRMC $/MWh
					Primary		Primary Fuel	Primary Fuel					Primary Fuel
Southdown	Mighty River Power	Auckland	OCGT	N	NG	45	9500	5.51	0.65 (5)	1,115	105	50,175	100.6
Otahuhu C	Contact Energy	Auckland	CCGT	N	NG	380	7050	5.51	0.65 (5)	1,035	75	393,300	77.1
Huntly (U5 - e3p)	Genesis Energy	Huntly	CCGT	N	NG	385	7080	5.51	0.65	1,035	75	398,475	73.1
TCC2	Contact Energy	Taranaki	CCGT	N	NG	380	7080	5.51	0.65	1,035	75	393,300	72.9
Marsden	Mighty River Power	Ruakaka	ST	N	Coal	280	10800	4.25		2,145	105 (3)	600,600	96.7
Buller Coal	Solid Energy	Buller	ST	S	Coal	150	10300	2.90		2,610	105 (3)	391,500	89.7
Tasman	CHH	Kawerau	ST Cogen	N	HOG/NG	100	11000	0.00		2,240	225	224,000	63.7
Southland	Solid Energy	Southland	ST (supercritical)	S	lignite	400	10800	2.30		2,400	105 (3)	960,000	82.2
Rodney	Genesis Energy	Rodney	CCGT	N	NG	360 (staged)	8250	5.51	0.65 (5)	1,150	75	414,000	87.3

Notes

(1) Weighted Average Cost of Capital (WACC) 10%, nominal post tax.
(2) Base load plant assumed to operate at 85% Net Capacity Factor.
(3) Includes ash disposal allowance of $0.55 per tonne of ash.
(4) LRMC excludes any emissions charge that may be applicable.
(5) For gas delivered to Southdown and Rodney a capacity fee equal to the throughput fee has been included to allow for the additional gas transmision from the Maui Pipeline
(6) Includes fixed and variable O&M

Exhibit 6

Description	Year	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
O&M cost $/kW				42.0	42.0	42.0	42.0	42.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	From PB power report
Capital & O&M costs $m		790	1100	26.5	26.5	26.5	26.5	26.5	20.8	20.8	20.8	20.8	20.8	20.8	20.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	Capital cost $3000 x 630
Income from 2050 GWh $m @	**12.6**			258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	258.3	GWh*power price/1000 c/kWh
Cash flow $m		-790	-1100	231.8	231.8	231.8	231.8	231.8	237.5	237.5	237.5	237.5	237.5	237.5	237.5	220.5	220.5	220.5	220.5	220.5	220.5	220.5	220.5	
IRR	10.02%																							
Discount rate	10.00%			At $3500/ kW, power cost is 14.3 cents																				
NPV 20 yrs	$2.19	$m																						
With backup and transmission etc				**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	
Capital & O&M costs $m		790	1100	26.5	26.5	26.5	26.5	26.5	20.8	20.8	20.8	20.8	20.8	20.8	20.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	Capital cost $3000 x 630
Backup 350 MW		135	250	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	350 MW @ $1100/kW 10% CF $200/MWh
Transmission and system operation costs		25	75	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	Frequency keeping etc
Income $m (2050 +307 GWh) @	**15.0**			353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	353.6	GWh*power price/1000
Cash flow $m		-950	-1425	291.4	291.4	291.4	291.4	291.4	297.1	297.1	297.1	297.1	297.1	297.1	297.1	280.1	280.1	280.1	280.1	280.1	280.1	280.1	280.1	
IRR	10.05%																							
Discount rate	10.00%			At $3500/ kW, power cost is 16.5 cents																				
NPV 20 yrs	$7.41	$m																						
Comparable cost of Hayes	4550	$/kW	This cost excludes transmission and system operation costs because other projects will incur some costs of this type																					
Carbon tax for backup generation																								
Annual CO2 @ .6kg/kWh	184200	Tonnes																						
Percent renewable	85%																							
Carbon Tax @ $50/tonne $m	$9																							

Exhibit 8