Non-conventional Technologies as Alternative Solutions to the Proposed Whakamaru-Otahuhu Transmission Upgrade

A report to the Electricity Commission
PO Box 10041
Wellington

This report was compiled for the Centre for Advanced Enginering by:

R O'Brien	O'Brien Consulting
D Hume	Electric Power Engineering Centre University of Canterbury
I Bywater	Engenius Solutions

Executive Summary

This commentary brings together a preliminary view of the potential of non-conventional generation as a comprehensive alternative solution to the proposed Auckland transmission upgrade. It should be recognised that the alternatives reviewed here are but one choice amongst a range of various other options being considered by the Commission.

Specifically excluded from this commentary is evaluation of traditional base-load generation (or any extension of current generation facilities), demand-side programmes such as energy efficiency initiatives and load management, and also fuel substitution options.

In bringing this view together the report covers a number of work streams:

1. A high level evaluation of the non-conventional generation technologies as suggested by individual respondents during the Commission consultation process
2. A review of other technologies considered as having the potential to contribute to a broad portfolio of generation alternatives over the next 10 years
3. An assessment of the likelihood that the different alternatives will proceed within the ten-year time fame, given the level of technology development and possible market uptake.

In the absence of any commercial framework or market that encourages the uptake of alternative generation, it is not possible to make any realistic judgement of the level of uptake of non-conventional technologies over the next ten years.

In this respect it is worth noting that amongst the different proposals made to the Commission related to non-conventional generation there was not one that can be regarded as commercially based.

In other words, whilst there may be advantage in the development of non-conventional generation, in the absence of any adequate evidence that such projects will be financially viable, it is difficult to have any confidence that these projects will proceed.

It could be argued, however, that a more worthwhile option than looking for alternatives would instead be to ask the question as to what contribution Auckland might itself make towards meeting its future electricity supply needs. Although the city is attached to the National Grid, the scale of demand in this one city is sufficient to require its own planning base. To this end there are certain technologies that are worthy of further investigation. These to some extent are specifically Auckland orientated, although in most cases their application may be extendable to other regions of the country.

Within this context, we believe that the following four alternative options should be investigated further as, in at least two cases, they are very specifically Auckland orientated.

These are:

- Municipal solid waste to energy conversion;
- Increasing use of gas turbine and diesel generator sets;
- Tidal current systems; and
- Storage systems including pumped water storage.

All of the above have the potential to contribute towards Auckland's electricity needs. Only one however, the increasing use of gas turbine and diesel generator sets, falls within the current planning timeframe for the grid upgrade decision. Development of this opportunity will be largely driven by individual consumer views of the value of electricity security.

For the other identified options, significant more work is required to establish technical and commercial viability.

Beyond that point, it is our expectation that even under normal circumstances it will take between three and five years to permit and install a medium size generation facility, assuming no significant objections from the community.

The analysis contained herein is not intended as a replacement for detailed feasibility assessment. Any future consideration of non-conventional generation options will be dependent on resource assessments, engineering studies, business case development and, finally, consistency with all relevant environmental and statutory approvals.

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1 Non-conventional Generation and its Role in Support of Transmission Services

Transpower has a normal standard of delivery equivalent to n-1 grid security. Although the transmission system is not perfect it has a very low outage based on lost system minutes and, in fact, New Zealand has benefited from many years of high quality service delivery. Transpower has now identified the need for an upgrade of the main transmission grid supplying Auckland by the year 2010 if it is to maintain the n-1 grid security level.

However, not everyone in New Zealand requires this level of security, and thus, maintaining this level becomes a trade off against other alternatives. Moreover, with increasing energy and peak load demand requirements, it is not easy to support the level of system redundancy required to provide this high performance from a centralised system. Eventually the law of diminishing returns starts to function.

An alternative to attempting to force more power down the centralised grid system is to deliver power to the point of use, by installing many smaller scale generators distributed about the country. These generators do not compete with the conventional market pricing of electricity; they actually compete at the retail end of the business. However, there remain significant barriers to their introduction because of lack of familiarity about their potential use, the need for consumers to invest in capital plant, and the difficulties associated with establishing a suitable commercial case for investment.

Distributed generation, i.e. smaller generating plant connected close to centres of load, provides potentially several significant benefits when supported by a stable centralised transmission grid. Key advantages are the reduction in scale of the transmission system required, a diversified source of electricity, supplemental reactive power to assist in losses reduction, and voltage and frequency support. Most importantly, installing distributed generation can increase the security level above that provided by Transpower, to potentially equivalent to n-2 in some cases.

Converting an existing centralised system into a hybrid grid and distributed system requires some re-engineering of protection systems, and control systems as well as the adoption of adaptive management systems capable of supporting the interconnection of a large volume of non-firm generation. However, the long-term benefits provided by the ability to match market demand more closely by investing in smaller plant, with reduced losses, and potentially significantly improved efficiency and energy conversion, coupled with the development of intelligent network management systems, means that the supply and demand curves can be matched more closely to the advantage of the overall system.

This is particularly the case in extreme situations where stress is put on either the centralised generator through, for example in dry years, or on the thermal generators through (as we are now experiencing), high fuel prices.

1.1 The Potential for Distributed Generation

Capacity growth in an electricity system is driven by two key areas:

1. Local growth which is manifest in growth of demand within the network; and
2. Global growth manifest as growth on the transmission system.

Both of these can be substituted. Minimising losses within the network or generation at point of use can reduce the need for supplying greater capacity into the network. Generating within a network also reduces global growth. There is a limit to our ability to make the system bigger continuously from a central perspective as population and new demand grows away from the existing infrastructure. At some point of time forcing more power down the wire is less efficient than effectively removing the need for remote supply by generating within the network.

It is at this point that distributed generation (DG) has its greatest effect. Introducing DG results in grid reinforcement, it stiffens the network in terms of improving frequency and voltage control, and increases flexibility within the whole system. On a major transmission system DG may range from the largest generating plant down to relatively small reciprocating engines.

The scale of plant for distributed generation is definitely reducing. Sources of supply of equipment are also reducing the cost per kilowatt of generating plant capacity. Developing countries such as China and India, together with their very distributed populations and the complexity of installing major infrastructure systems, appear to be driving a change from the economy of scale in cost per unit of generation output to an economy of scale defined in terms of cost per unit of generating capacity.

The drivers for distributed generation come from three sources.

1 The first is the market. Market forces are driven by fashion on the very small scale (residential), and economics at the commercial and industrial level. With the reducing cost per unit of generating plant capacity, scale is now reaching the size where DG is becoming a viable proposition in some circumstances.

2 Climate change policy also offers a new opportunity through regulatory requirements (in some cases) for reduced emissions, requirements for greater efficiency of conversion of energy, and the use of carbon credits to support distributed generation at point of use. This is a key development as it offers the potential to reduce transmission system losses, which can be very significant in an extended grid such as New Zealand.

3 The third area of development has been driven by the RMA. Local expectations (such as for example the air quality requirements in Christchurch) are creating pressure against continued use of conventional sources of thermal energy, leading to the adoption of high-efficiency combined heat and power generators as well as more sophisticated air quality management systems. These techniques are far easier to manage on small generating plant than large.

Gas-fired thermal generation requires specific comment. Conventional large-scale gas-fired thermal power generating plant normally require a 20 year lifespan to make a project decision. The gas reserves essential for underwriting the economics are set at the 2 P level (i.e. a 50% confidence level that the gas available from the reservoir will eventually exceed, or at least meet, expected requirements over the life of the plant). The result of using this risk factor has been, in the past, to require multiple gas sources for project finance in order to manage supply risk for the generator. However we are now seeing the consequences of smaller gas discoveries, leading to new generating plant being more typically sized against the gas reserve. This means to satisfy the risk elements of most of these developments future plant capacities will be smaller than they has been in the past.

As previously stated, other studies have indicated that many consumers do not in fact require the level of security offered by the transmission upgrade and thus investment in DG (or demand side measures) will give some the opportunity to contract out thereby freeing up capacity, and by using tiered pricing mechanisms, allow load shedding on demand to manage capacity constraints.

In this respect we differentiate in this report between conventional and non-conventional generation on the basis of scale, technology maturity and interconnection as described in Table 1.

Limiting the definition of DG to a particular MW size is unwarranted. A more useful characteristic is to define DG on the basis of interconnection to the utility distribution system.

Therefore, in the technology review, we first examine the non-conventional generation solutions offered to the Commission plus other non-conventional sources for DG. This incorporates consideration of both firm and non-firm capacity. Our assessment of the likely contribution of these sources towards grid security focuses primarily on the non-conventional DG applications. We take the view that other conventional generation opportunities will be taken up as the economics and market dictates.

CONVENTIONAL	NONCONVENTIONAL
Electricity capacity driven	Not electricity capacity driven
Trunk located	Local
Centralised	Non firm
VALUES	VALUES
Contracting out of n-1	Risk transfer to owner
Maximise transmission efficiency	Off grid, reducing transmission capacity, demand, connection charge
Reduces losses	Reduces losses
Avoid capacity upgrade	Avoid capacity upgrade
Near-term	Future
COMMENTS	COMMENTS
Conventional distributed generation is institutionally driven	Non-conventional and non firm power is made possible by improvements in technology
The scale of conventional DG is greater than 5 MW. This can be supplied by gas turbines, geothermal sources, pumped storage, tidal, and wave power. The key constraints are the fixed location, the maximum efficiency of approximately 60%, and that the electricity has to be contracted.	Technology is moving towards providing less than 5 MW generating plant at an economic capital price. This includes Micro turbines, combined heat and power, photovoltaics, solar energy collection, and many wind power systems. The location is a point of use, maximum efficiency obtainable can rise as high as 80%, and it is a voluntary process.

Table 1: Conventional and non-conventional generation characteristics

2 Review of Relevant Submissions

As previously stated, submissions so far received by the Commission have largely covered conventional DG opportunities, basically to meet energy demands rather than any other specific capacity or security requirement. Specific proposals put forward are listed in the papers from the Electricity Commission Board meeting of August 2005. These included just four specific generation alternatives to the proposed transmission upgrade plus, three more generic technology options.

Two institutional submitters also put forward their generation plans while noting they didn't consider them as alternatives that will avoid the need for upgrading transmission capacity.

It should be noted here that the main issue behind the transmission upgrade is to provide peak power to maintain the n-1 security of supply to Auckland. Viable alternatives to the transmission upgrade have to fall within the following three categories:

- Base load generation – continuous generation;
- Peak load generation – generation during period of high demand (generally between 200 and 3000 hours per year); and
- Non-firm generation plus storage capability.

Below we comment on the various submissions as provided to us by the Commission, noting that no storage technologies were included. More detailed consideration of the different generation options described is provided in the DG Technologies discussion section, plus additional technologies such as storage and other options not noted in the submissions.

2.1 Oceans Energy

Two submissions cover oceans energy.

The first proposed a tidal electricity development in both the Manakau or Kaipara harbours. At first sight the capacity offered by these units at 2 MW each seems rather small in relation to the demand growth in the Auckland market place. However there may be some merit in keeping this proposition in mind should an alternative second harbour crossing be constructed at any stage in the future involving a road causeway where turbines could be incorporated in the structure.

The second is a general proposal for tidal generators. Again the submission discusses small turbines of approximately 1 MW capacity. Some significant arrays of turbines would be required in the various harbours to provide substantial augmentation of the power delivery to Auckland. The short description given indicates that any power generated in this manner would require some substantial supplementation for the ten hours per day where there is no tidal movement. However electricity produced from this source could be used as a low-cost means of providing pumped storage for peak shaving.

2.2 Thermal Power Generation

There were three thermal fuels proposals identified amongst the various submissions.

The first proposal considered was for a waste to energy power station in Auckland. This is not a new concept having been pursued in the recent past by a company that examined the options of using the Meremere power station for a similar proposal. It has also been considered at other locations in the North Island close by or at coastal ports. The information that is available from other sources, (commercial in confidence), indicate that the presented numbers may well be under estimating the amount of rubbish that could be available for power generation. Nevertheless their estimates are that a 20 MW power station would cost $200 million. This is close to 10 times the price of the alternative gas turbine or diesel fired power station of that scale. Given the complexities of transporting large quantities of refuse, the resource consent requirements, the health requirements, and the general public resistance that is likely, a premium of that scale seems unreasonable.

A second submission proposed a modular 200

MW gas-fired plant in the Auckland region. Although conventional in its concept the company has access to sufficient gas, and is exploring for gas to supplement the requirements of a plant of this scale. It is noticeable that the size of the proposed plant has now been matched more closely to the reserves of gas that may be available for its economic life. Although it is not possible to quantify the future exploration success for gas in New Zealand it is certainly possible to say that more gas will be discovered, and made available to the market at a price. In the final analysis, at least for the foreseeable future, the backup source of gas is imported LNG. The use of gas turbine plant provides substantial flexibility, ease of construction and relatively low cost and has to be seen as having a substantial future in the short to medium-term.

A third proposal suggested a small-scale thermal power generation plant, at a slightly smaller scale even than those above, but clearly demonstrating a 'market following' capital expenditure expectation. Noting that at least one of these plants was proposed to operate on diesel fuel we consider this to be a demonstration that the future for smaller distributed power generation plant from 200 MW down within the marketplace in Auckland may well be the norm for the future. Trustpower highlighted a significant problem however in that it pays for the cost of transmission whether or not it is used. This should be investigated, as it is possible that the avoided cost of transmission could be a refundable revenue source for distributed generation operators.

2.3 Wind and Hydro

There were two submissions suggesting small-scale wind and hydro projects. All of these projects seem to have merit within the scheme of things, however, they are collectively inadequate to meet the growing demand in Auckland, except as supplemental energy to substitute for remote supplies from the South Island. At which point their value equals their output plus avoided losses.

It was also noted that unless reactive power was installed at the wind farms then the effect on the transmission system would be negligible. This identifies one of the key problems that must be addressed for Auckland. Developing more distributed generation within the Auckland region clearly improves the reactive power situation.

3 DG Technologies Summary

In order to develop a coherent view of the likely non-conventional sources of alternative generation it is important to consider how the DG market might mature over time. Applications for DG include co-generation, standby or back-up power, peak lopping, power quality and system support, plus others. With respect to technology type, there are many technologies available in the market place today. These vary from photovoltaic systems to fuel cells, micro turbines, combustion turbines, wind turbines and reciprocating engines; the latter currently being the dominant technology. Furthermore, storage technologies such as fly wheels, batteries and ultra capacitors are beginning to evolve into the market place.

Each of these technologies has its own unique characteristics, cost-performance attributes and competitive position, which will change over time. In respect of the required ten year horizon placed on this review it can be reasonably argued that anything not already proven, or available at beta-stage prototyping, is not likely to feature in the near term.

3.1 Reciprocating Engines

Reciprocating engines (either spark ignition or compression ignition) are available in sizes that range from 1kWe – 15MWe. Cogeneration capability also exists since most of the input energy leaves as heat in the exhaust gas and the cooling water. The engines are widely used for back-up supply and mobile generation. The use of present consumer standby diesel sets presents a good DG opportunity. It is a reliable technology, with substantial amount of plant already installed and sunk capital cost. Furthermore, there is a need for these installations to be tested at intervals to ensure reliable operation. With a change in the way these units are controlled and integrated with the electricity market, greater value can be obtained from such assets.

The present impediment to operating diesel generating plant in urban centres is the ongoing tightening of air quality standards The air emission quality issue will only improve over time as New Zealand's diesel production turns to low sulphur levels, which in turn will allow the use of catalytic converters to improve further air quality standards, although these are expensive. The opportunity also exists to use biodiesel or biofuel blends.

Dual fuel engines offer an alternative that combines the reliability and efficiency of a diesel engine with the emission benefits of natural gas. New natural gas units focus on lean-burn technology that uses a higher ratio of air to fuel than traditional units but at the cost of a lower power output. Incorporating a turbocharger to increase power density can compensate for this.

Reciprocating engines are manufactured by a large group of companies throughout the world in a wide size range. Current development trends seem to be focused on efficiency and emission issues and on reducing costs. A representative group of manufacturers is listed in the table below, along with some available models and current projects.

The capital cost of diesel generators (depending on size) is of the order of NZ$300-500/Kva,

Manufacturer	Model	Notes
Caterpillar	Compact modular generator set	Focus on combustion, air-intake, exhaust sensors and engine design to increase efficiency and reduce emissions.
Waukesha Engine	Natural gas and fuel flexible engines; lean-burn versions	Developing a new gaseous-fueled engine with improved air handling, exhaust treatment, combustion & system integration
Cummins Engine Co.	Diesel and gas engines: 5 kW to 2000 kW	Developing high-pressure natural gas engine systems. Stand by, prime power and load management applications.
Jenbacher AG	Cogeneration units; electrical output from 70 kW to 2,700 kW.	GE Power Systems and the Jenbacher Group have expanded their current distribution agreement
Wartsila Corp.	Diesel, lean-burn, dual-fuel and gas-diesel engines. 1 MW to 300 MW	Announced joint venture with Cummins Power Generation

Table 2: Reciprocating engine manufacturers and models (ref. 1)

demonstrating the maturity of the product. Installation costs will increase the prime cost by a factor of about 1.4.

3.2 Gas Turbines

Gas turbines have been in use for over 40 years in the electricity generation market and range in size from simple cycle units starting at about 1MW to over a hundred MW. Their appeal has been that they are relatively cheap to build and are ideal for emergency and peak-load standby use because of their rapid starting and loading capabilities.

Liquid or gaseous fuels are combusted within the turbine creating an expansion of gases. As these gases expand and leave the turbine, they exit through a system of blades that absorb some of the energy and convert it into mechanical energy to rotate the generator.

Gas turbines typically convert 20-45% of the input energy into electrical energy. The gas turbine exhaust can be used to produce steam that drives a condensing steam turbine and this will achieve up to 58% fuel to electric efficiency. By siting the plant near thermal users and switching to a backpressure steam turbine, combined cycle gas turbine CHP plants can achieve efficiencies of 85% to 97%.

Units from 1-15MW are generally referred to as industrial turbines, which differentiate them from larger utility grade turbines and the smaller microturbines. They can make a significant contribution even if used infrequently in a DG application. Gas turbines have been rarely used in DG situations in New Zealand.

Turbines are currently available from numerous manufacturers (see Table 3). The next generation of turbines is under development. The Advanced Turbine System programme, sponsored by the U.S. Department of Energy, seeks to increase turbine efficiency and lower NO_x emissions through the use of recuperation and advanced materials.

The capital cost of a gas turbine power plant can vary between US$400-US$900/kVA with the lower end applying to large industrial frame turbines in combined cycle configurations. Installation costs will increase the prime cost by a factor of about 1.5.

3.3 Microturbines

Microturbines are derived from aircraft auxiliary power systems, diesel engine turbochargers and automotive designs. They are NOT a scaled down gas turbine. Typically in the 25-500 kWe range, they are capable of electrical efficiencies of between 20-30% with the clear possibility for use in cogeneration mode. These systems are now becoming commercially available although they remain expensive and have a longer start up time than for reciprocating engines. There remains ongoing scope for cost reduction and efficiency improvement.

In a DG situation, the microturbine is a candidate for use in a standard package with identical units installed in parallel if the size of the load dictates it. Microturbines are quieter in operation than equivalent sized combustion engines, but reliability is yet to be proven. Manufacturers now offer package units able to be paralleled for greater capacity requirements, with or without heat recuperation, with load following or export control of the generator.

Manufacturer	Model	Notes
Alstom	Gas turbines to 50 MW, combined cycle from 50 to 265 MW.	Fueled by natural gas, light oil, crude oil or coal gas. A switching facility eliminates dependency on any one fuel.
Kawasaki	Output from 650 kW to 30 MW. CHP, standby and combined-cycle.	Will market and sell the GPB15X generator package with Catalyticas' Xonon™ Cool Combustion system.
Nuovo Pignone	Turbines range from 2 MW to 124 MW.	Nearly 1300 installed with more than 55 million fired hours
Pratt & Whitney	300 to 5000 kW for Generators, CHP, Auxiliary Power.	Formed New Industrial Gas Turbine Unit P2 Energy, LLC this fall.
Rols Royce	Units to 150 MW, aeroderivative gas turbines and diesel engines.	Announced business re-organization, will concentrate its Energy business large gas turbine operations in Montreal.
Solar	Units from 1 to 15 MW	Solar has the largest market share in the 1 to 15 MW size range

Table 3: Turbine manufacturers and models (ref. 1)

3.4 Stirling Engines

Stirling engines are external combustion systems since the fuel does not enter the working cylinders. Instead, it is combusted outside of a cylinder to warm an inert gas, which is sealed within the cylinders. It is this inert gas, typically hydrogen or helium, which does the actual work on the pistons.

Stirling engines operate on temperature differences of many hundreds of degrees and so require a high temperature source, either from fuel combustion or from a heat source such as concentrated direct sunlight, and a cold sink usually provided by water-cooling. Again, as with the case of internal combustion engines, this heated water can be put to use to provide CHP.

Stirling engines, like microturbines, are inherently quieter operating than internal combustion engines but are technologically less mature. Also, Stirling engines are being developed at a scale smaller than microturbines, and are focussed more on the domestic CHP market (a.c generation) and remote area power supplies (d.c. generation).

Currently, Stirling engines are capable of electrical efficiencies of 12-25% in the 1-25 kWe range and commercial availability is now becoming reality.

All Stirling engines are inherently fuel insensitive, so either the combustion of a solid, liquid or gas fuel, including biogas, can be used, to even direct concentrated sunlight.

3.5 Fuel Cells

Although the first fuel cell was developed in 1893, the technology was not put to practical use until the 1960's. There are many types of fuel cells currently under development, including phosphoric acid, proton exchange membrane, molten carbonate, solid oxide, alkaline and direct methanol. Fuel cell are not generally commercially available as standard units although there are number of companies that offer units for commercial delivery. Capital costs remain high - in the $6,000-$10,000+/ kWe range.

Fuel cells, ranging in size from 1 kWe to 10 MWe, are electrochemical energy conversion devices that use hydrogen and oxygen to produce electricity, heat, and water. The electrical production is relatively efficient when hydrogen fuel is used (40-60%) since there is no combustion or large moving parts involved and therefore less energy conversion to heat losses. Where a supply of hydrogen is not directly supplied it is necessary to have, in addition, a hydrocarbon fuel reformer. Also, fuel cells produce direct current and therefore require inverters to enable the output to be synchronised with the grid.

The future potential for fuel cells as on-site DG power plants is dependent on significant cost reductions, which the leading vendors believe will occur with volume sales. The molten carbonate technology and the solid oxide technology both achieve close to 50% fuel to electricity efficiency and both have exhaust heat suitable for combined cycle plants and CHP. The current technology has nearly zero

Fuel Cell Technology	Electrolyte	Operating Temperature	Efficiency	Fuel Requirement
PEM (proton-exchange membrane)	Polymer	75°C (180°F)	35%-60%	Pure hydrogen or methanol (natural gas requires a fuel reformer)
PA (phosphoric acid)	Phosphoric acid	210°C (400°F)	35%-50%	Hydrogen, but not as pure as PEM (natural gas requires a fuel reformer)
MC (molten carbonate)	Molten carbonate salt	650°C (1200°F)	40%-55%	Hydrogen, natural gas (integrated reformer)
SO (solid oxide)	Ceramic	800°C-1000°C (1500°F-1800°F)	45%-60%	Hydrogen, hydrocarbons (no separate reformer)

Table 4: Fuel cell technology characteristics (ref. 2)

emissions of NOx and can achieve comparable efficiency to the largest combined cycle gas turbine (CCGT) central plant.

The current capital costs per kilowatt of capacity and uncertainties about the component lives have limited fuel cell penetration of the DG market. At the end of 2001, there was a worldwide total of only 45 MWe of fuel cell capacity with 1 GWe projected for 2006.

4 Fuel Supplies

It is not intended to cover fuel supply issues in any depth, but fuel supply issues are likely to dominate economics and thus the viability of DG investments as they do for large centralised power generation options. The essential challenge in any investment is to ensure resource availability coupled with long term supply contracts at a stable and predictable price.

A number of submissions made reference to the use of biomass, waste-to-energy and geothermal hot rock generation as follows.

4.1 Biomass

Biomass is regarded as a renewable fuel and is regarded as having considerable potential for use in DG cogeneration systems; particular within the forest industries. For electricity generation, the potential energy stored in biomass is typically extracted in one of the following ways:

- Direct combustion of the biomass within a boiler can produce steam to drive a steam turbine.
- Processing the biomass through a gasifier or pyrolyser. This converts the cellulose and lignin materials into a combustible gas that is then used as a fuel, e.g. for a gas turbine or CCGT.
- Liquid biofuel, e.g. biodiesel, replacing the equivalent fossil fuel type often with dramatic improvement in the technology's emissions standards.

Currently the generation of electricity from forest-derived biomass is generally not financially viable unless the source of wood waste for fuel has a negative value; in other words, if there is a cost of disposal that would otherwise be incurred if it could not be used as fuel. Development of these types of power sources will continue as timber processing develops in New Zealand, but is most likely to be available in the central North Island or other provincial regions, as opposed to Auckland.

4.2 Municipal Solid Waste

Municipal solid waste (MSW) is a potential fuel source for an Energy-from-Waste (EfW) power station using thermochemical conversion. At present, Auckland's annual MSW volume is some 970,000 tonnes, over the region as a whole, which goes to landfill. Landfill gas produced in time by the anaerobic decomposition of the waste below ground is currently providing some electricity generation capacity. This is on the whole a low scale technology, well suited to urban environments where existing landfills have been established over the years. It is to be expected that specialised biomass management systems will eventually be developed that could be used to supplement local production and generation. An example is the novel "sludge lysis" plant operated by WaterCare Services, which decomposes sewerage sludge into biogas. The plant has 6.8MW of installed capacity on-site and generates about 40 GWh/y electricity – off grid (ref. 3).

Solid waste to energy plants have transformed significantly from the first generation waste incineration plants of 50 years ago. Modern technology approaches are to use gasification plants of various configurations, whereby the waste is heated to produce fuel gasses, and these are subsequently burnt to produce steam for power generation. Controlled air conditions ensure the maximum efficiency of gasification. In the complete absence of air the waste is pyrolysed into carbon char and combustible gasses.

A modern plant (see flow chart in Figure 1) using first-stage pyrolysis, then a second-stage of gasification of the char using steam (water shift reaction), and a third-stage combustion of the pyrolysis gasses and hydrogen/ carbon monoxide gasses from the gasification stage, is able to provide the process heat requirements and emissions that meet the highest international requirements. The heat of combustion provides the process heating as well as generating surplus heat to produce power via steam turbines.

Several modular plants for Auckland, using this proven technology approach, have the poten-

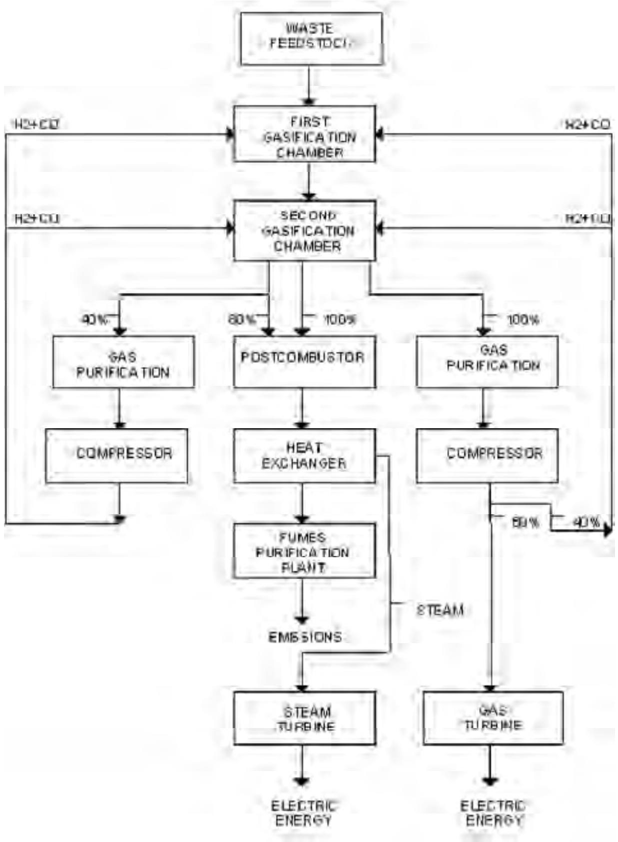


Figure 1: Waste gasification flow chart (ref. 4)

tial to generate up to 30MW of base load. A summary of typical investment and operation costs given from recent international examples is provided in Table 5.

4.3 Agricultural Wastes

Beyond these applications, the increasing attention and more demanding requirements for improved treatments for the disposal of waste from farming and other agriculture-based industries has become a major driver towards increased waste processing to produce biogas. This is likely to have a significant influence on the uptake and potential for DG applications.

	Plant Size Range kTpa	Capital Cost US$/Tpa	Operating Cost US$/T
Pyrolysis			
Compact Power	30 - 100	250 - 100	n/a
Ensyn	50	320	n/a
Pyrovac	150	190	n/a
Serpac-Pyroflam	8	500	60 - 75
Thermoselect	80 - 250	680 - 550	45 - 145
Von Roll	45	400 - 450	125 - 190
Gasification			
Enerkem	30	350	n/a
Foster Wheeler	85	150 - 200	n/a
Organic Power	6	380	n/a
PRM Energy	50	80	n/a

Table 5: Pyrolysis and gasification plant capital and operating costs (ref. 4)

For example, a recent estimation of the energy gain possible from wide spread deployment of on-farm cow shed biodigesters, co-generation plant and milk-chilling plant for farms north of Auckland suggests the potential to save up to 52GWh p.a. and a load reduction of 9MVA. The system has wider environmental benefits other than energy saving and load reductions. The load demand however, is not coincident with the Auckland region peak.

4.4 Geothermal

New Zealand has extensive expert knowledge of the extraction of underground geothermal heat and the transmission of steam for electricity generation. Historically this has been confined to large-scale electricity production. With declining ability to extract the geothermal energy because of perceived environmental issues there opens up an extensive range of DG opportunities. A paradigm shift in thinking on the use of geothermal energy can have appropriate technologies (eg Binary plant) linked to cogeneration applications. The cost of well drilling can be a barrier to extraction for electricity production alone, but in a multi-use situation the cost per unit of available energy can be significantly addressed. This is accentuated if new industrial plant is located at the site of the geothermal energy rather than currently happens where the energy has to be taken to the industrial site.

Auckland sits over the Auckland Volcanic Field, an array of 49 discrete volcanoes. These originate from the presence of a region of Hot Rock, 100km beneath the city. An important aspect of this style of volcanism is that there is no crustal magma reservoir present between eruptions and hence no source of heat to drive geothermal systems as there is in the central North Island. Apart from this the Ngawha Geothermal station 8MW in Northland is the only geothermal station above the planned transmission line upgrade.

There may be a case for Hot Dry Rock although no research has been done on this and is dependent on many geological factors.

4.5 Hydro

Run of the river, and impounded water behind storage dams or coastal barrages, are the usual type of hydro-electric works. Impounding water demands land area to be sacrificed, creating a new lake or raising the level of an existing one. This aspect alone now greatly constrains the number of proposals unless strong support comes from the community affected, usually only where there is an over-riding interest in dual use of the water reservoir i.e. with irrigation. This was the initial technology of choice for electricity production and was installed for DG applications. As a form of energy storage pumped hydro schemes can be very useful as described in the next section.

The review of submissions received identified three or so small-scale hydro possibilities. In addition, there are a number of limited opportunities for mini-hydro installations associated with Auckland's municipal water supply. However, none of these sources of supply are of a sufficient scale to underwrite the development of the Auckland electricity market.

5 Intermittent DG & Storage

This section discusses the options of intermittent DG as well as storage schemes that could possibly be coupled with such generation. Intermittent wind and tidal power coupled with energy storage offers an opportunity to supply on demand peak load. In fact, energy storage, without any extra generation could be used to help the Auckland system.

The figure below from the Transpower document “Security of Supply into Auckland – October 2004” outlines the typical winter profile for Auckland with load profile predictions till 2015. The solid line indicates the Capacity limit to keep the system in a secure “N-1” state. The same issues may apply in summer when system generation capacity limit is less due to maintenance of existing major plant.

Integrating the energy area under the N-1 capacity limit in Figure 2 gives a much larger area (hence energy) than that over the capacity limit line during the two peak load areas defined by the plot. Hence, an energy storage facility, such as pumped hydro (if applicable) or even newer technology such as a large Flow Battery could be used on a large scale to alter this peak demand curve, by storage of energy during off-peak times and releasing this back into the system during peak times.

Depending on the market signals, this presumably would attract an economic value by storing energy when cheap and selling when high.

5.1 Wind Generation

Electricity generation from wind turbines is well understood, where the mass of air is converted into rotational mechanical energy by aerofoil blades or other types of devices such as the Wells turbine operating from an oscillating air column.

One identified option was a wind farm of 50MW in North Auckland with the potential to supply up to 47MVAr of reactive power during zero generation conditions. Economics will be dependent on average wind speed and availability. Most of the wind farms being contemplated in New Zealand are not predicated upon DG opportunities. Comment on this type of generation is beyond the scope of this report.

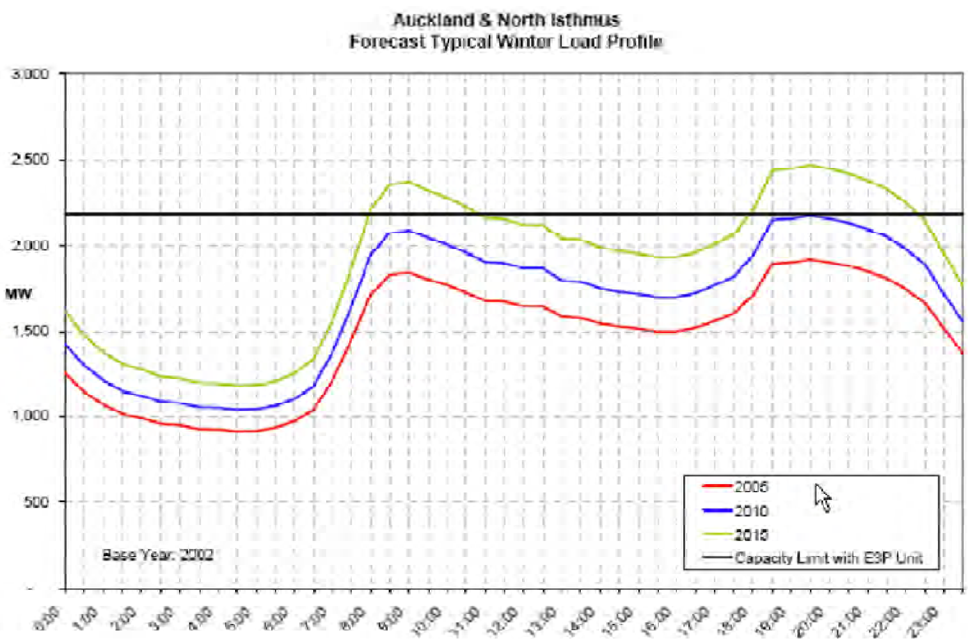


Figure 2: Auckland and North Isthmus Typical Winter Load Profile

There are, however, also available wind turbine packaged systems designed specifically for the residential sector (less than 5kW) or larger units (up to 100kW) installed to meet local community needs. In this configuration wind as an intermittent renewable energy resource will fit best in a support portfolio since it requires a degree of firm capacity backup or energy storage. The DG opportunity is therefore limited to meeting the local demand of a defined network area not requiring 100% backup and improving the economics of grid support charges. Beyond 20% of local distributed generation those benefits are expected to diminish. (Note: large-scale wind farms can compete at a higher level of penetration along with other forms of grid-connected generation but principally for supply to the wholesale electricity market).

Therefore, from the perspective of DG, small-scale wind offers an opportunity for the future, but the opportunity is not there now. It will only exist at the utility network level if there are other DG opportunities that can be taken up as part of a portfolio or if energy storage schemes such as pump storage are partnered with the wind scheme.

5.2 Solar

Direct conversion of sunlight into electricity has been commercially available at a price for decades. The principal technology is the incident solar radiation on a silicon cell semi-conductor, which the produces a flow of direct current. Like a fuel cell, photovoltaic (PV) panels require an inverter for DG applications connected to the grid.

Other forms of PV technology are emerging from the laboratory, but the high capital cost has largely confined their application to specialist needs like low power requirements in locations remote form the grid. Of all the new technologies it is the one that least requires any ongoing maintenance. Using PV panels as a roofing surface on all types of building, once sufficient cost reduction had been achieved, would open up the market dramatically for PV-DG systems.

New Zealand's solar insolation levels are relatively high for the country's latitude. Photovoltaics have therefore the capacity to perform well, although from the viewpoint of large-scale use on networks, the capital cost will have to dramatically reduce. In its favour PV can be largely made unobtrusive and it is practically maintenance free.

However, New Zealand has a winter peak and energy prices summer to winter are 1:2 or greater, so the prognosis is for PV not to contribute to network connected DG but to remain in a niche market for holiday homes and other remote power applications where the cost benefits are justifiable. While in energy terms this may not be a large contributor to DG it is likely to be large in the number of applications.

Direct solar energy can also be used to heat a fluid that in turn is used to produce steam for a steam turbine, but few commercial applications have been designed and built in the world, and none are currently in operation.

5.3 Tidal Range and Ocean Currents

Several submissions were made to the Commission on Tidal Power although none stated explicitly the potential energy that may be able to be harnessed from such schemes. We comment that in addition to tidal flow systems, simple utilisation of tidal range can provide a means of using conventional hydropower technology, whereby the water at high tide is captured behind a shore-base barrage and held until required or at low tide, when the water is run out to sea again.

Tidal difference across an isthmus can be employed if the pipe loss is not insurmountable for the head difference. Ocean currents close to shore or caused by tidal flow in and out of natural harbours can be harnessed with special turbines much like wind power. However, in most cases the technology challenges of operating in a hostile marine environment have been sufficient to reduce the economic viability to interest level; as opposed to baseload generation.

Although the technology is relatively immature one turbine manufacturer in England, (Marine Current Turbines) has tested a 300kW prototype and is currently in the process of prototyping a twin 1MW turbine. From their webpage "It is also planned to install single systems in overseas locations to form the starting point for developing the technology in new markets. Areas of special interest include North America, S E Asia and Australia and New Zealand. These projects depend on finding suitable local strategic partners who can continue to roll out the technology in their regions under a license agreement."

It has not been possible in this review to consider in detail the tidal resources available in the Auckland region. However, and as an example, we have taken a cursory look at the potential energy available from tidal flows occurring in the Manakau Harbour.

The energy able to be harnessed from tidal power is related to the volume of water that enters and exits the harbour on the flood and ebb tides. This movement of water occurs on a semi-diurnal basis allowing approximately four generating regions per day, twice on the flood tide and twice on the out going ebb tide. Several papers have been written on the hydrodynamics of Manukau harbour (ref. 5). From these a rough idea can be gained into the tidal characteristics of the harbour as well as the average tidal height and average volumes of water flow within the harbour.

The average tidal variation on the spring and neap tides in the Manukau harbour is between 0.8m and 4.1m (spring) and 1.5m and 3.5m (neap) above the nominal sea level. So an average between both spring and neap is 1.15m (low tide) to 3.8m (high tide) with a mean height above sea level of 2.5m.

The area of the harbour at high spring tide is around 340km^2 and at low tide around 220km^2. From these numbers, the average volume of water moved into and out of the harbour can also be roughly calculated, of around 340Mm^3 (340 Million cubic meters).

Assuming the average height of 1.9 meters and the simplified assumptions of tidal volumes, then the total potential energy per day lies somewhere between 9200MWh to 15000MWh (on average).

This is considerably more than the energy required in Transpower's load curve. Tidal variations mean power would be produced for around 13 to 14 hours per day but unlike wind this variation in power occurs over predictable periods. Harnessing this energy is the problem. It should be noted that the total power potential based on the Manakau is an order of magnitude greater than the potential power output from any wind farm located in the same region. It is the consideration of the energy density that should ultimately drive the economics towards tidal over wind in that location.

5.4 Energy Storage

Energy storage is not a new concept in the electricity sector. Utilities across the world have built pumped-hydro facilities and other techniques have been used or are in the course of development, including compressed air storage and lead-acid and other types of batteries. New Zealand's significant hydropower capacity and large wind power resource gives it virtual pumped storage from wind farms, when wind power at times can be used to hold back hydro lake levels. Energy storage of various forms can be used for load levelling / peak load demand, frequency response, and voltage control.

At a different scale, energy storage is also commonly used at the consumer level to ensure reliability and power quality to customers with sensitive equipment. Another traditional application is with off-grid supply, again mostly in conjunction with intermittent renewable energy sources.

Applications for electricity storage technologies apart from deferral of system and plant upgrading are:

- load management (load levelling, ramping and load following);
- spinning reserve (fast response and conventional);
- system stability and voltage regulation;
- renewable energy applications; and
- end use applications (UPS, peak shaving and emergency back-up).

Traditionally, electricity storage technologies have been used for the technical benefits they bring to electrical systems. In a liberalised electricity market, a new application for energy storage presents itself for price arbitrage (buying at low price, storing and selling at a high price). The key characteristics of storage technologies that determine which applications they are most suited for are: discharge duration; power rating; energy storage capacity; response time, and costs in the context of benefits.

Electricity storage systems can be categorized as shown in Table 6. The main electrical storage technologies that are appropriate according to need, are shown in Table 7.

It is important to note that these technologies are at varying stages of technological maturity.

Pumped hydro energy storage (PHES)

Pumped hydro energy storage (PHES) is a mature and familiar technology and has been utilised within electricity systems for many years. It is the most widespread energy storage system currently in use on power networks, operating at power rating up to 4,000 MW and capacities up to 15 GWh.

PHES uses the potential energy of water, transferred by pumps (charging mode) and turbines (discharge mode) between two reservoirs located at different altitudes. Currently, the overall efficiency is in the 70-85% range although variable speed machines are now being used to improve this. System efficiency is limited by the efficiency of the deployed pumps and turbines (neglecting friction losses in pipes and water losses due to evaporation). Plants are characterized by long construction times and high capital costs.

In 1994 there were approximately 50 to 60GW of installed pumped hydro stations worldwide (see Table 8). Foyers in Scotland, on the shores of Lock Ness, is an interesting example as it has a similar head and output capacity to a potential Auckland scheme in the Nihotupu catchment (as discussed in the Appendix to this report).

A review of the potential for pumped storage in the Waitakere Ranges is provided in Appendix 1. This preliminary assessment suggests that a Waitakere scheme may well be technically feasible, potentially providing up to 1300 MWh of pumped storage capacity. The size of such a scheme however and its mode of operation will be dependent on many factors, including:

- Hydrological issues.
- The future scale and uptake of intermittent generation in the Auckland region.
- The required 'peaking' power demand and the length of time it may be required.
- Possible system upgrades in the future, such as increasing the Upper Reservoir capacity.

Such systems would use Francis-type reversible turbines. These can be reversed for pumping with maximum pumping power often greater

Mechanical	Electromagnetic	Electrochemical
Pumped Hydro	Super-Capacitors	Batteries
Compressed Air	Super-Conducting	Flow Batteries
Flywheel	Magnets	Hydrogen

Table 6: Electricity storage systems

Power Quality	Market Related	Long term fluctuations
flywheels	pumped hydro	pumped hydro
hydrogen	hydrogen	hydrogen
batteries	batteries	batteries
flow batteries	flow batteries	flow batteries
	compressed air	compressed air

Table 7: Electrical storage technologies

Station	Country	Pumping head m	Unit number capacity type MW	Station capacity MW	Year of commission
Imaichi	Japan	52 4	3x350-VR(1)	1050	1984
Kiev	Ukraine	65		225	1966
Ludington	USA	98	6x312-VR(1)	1872	1974
Zagorsk	Russia	100	6x200-VR(1)	1200	1988
Foyers	UK	182	2x150-VR(1)	300	1974
Taum Sauk	USA	240	2x230-VR(1)	460	1963
Juktan	Sweden	260	1x334-VR(1)	334	1978
Vianden	Luxembourg	287	9x105-HF/C(2)	1141	1959
Racoon	USA	317	4x383-VR(1)	1532	1978
Mountain Ffestiniog	UK	320	4x 90-VR(1)	360	1963
Cruachan	UK	360	4x100-VR(1)	400	1966
Waldeeck II	Germany	329	2x220-VF/C(1)	440	1974
Rodund II	Austria	324	1x283-HF/C(2)	283	1976
Bath Country	USA	387	6x457-VR(1)	2740	1985
Robiei	Switzerland	410	4x 41-VR(1)	[illegible]	1968
Drakensberge	South Africa	473	4x270-VR(1)	1080	1981
Helms	USA	495	3x358-VR(1)	1070	1981
Numaparra	Japan	508	3x230-VR(1)	690	1973
Ohira	Japan	512	2x256-VR(1)	510	1975
Okuy Shino	Japan	539	6x200-VR(1)	1200	1978
Dinorvig	UK	545	6x300-VR(1)	1800	1982
Tamaharo	Japan	559	4x300-VR(1)	1200	1983
Hondawa	Japan	577	2x306-VR(1)	612	1983
Bajina Basta	Yugoslavia	621	2x315-VR(1)	630	1983
Hornberg	Germany	635	4x248-HF/C(1)	992	1974
La Coche	France	931	4x 80-VR(6)	320	1976
Chiotas	Italy	1070	8x150-VR(1)	1200	1980
Piastra Edolo	Italy	1260	8x127-VR(5)	1016	1981
San Fiorano	Italy	1404	2x125-VP/C(6)	250	1974

V: vertical shaft
H: horizontal shaft
F: Francis turbine
P: Pelton turbine
C: centrifugal pump
R: reversible pump turbine
( ): number of stages

Table 8: Worldwide installed pumped hydro stations (1994) (ref. 6)

than the generating power, if required.

Compressed air energy storage

Compressed air energy storage is also a mature technology but much less deployed than pumped hydro. The electricity is stored by compressing air via electrical compressors in huge storage facilities, mostly situated underground in caverns created inside appropriate salt rocks, abandoned hard-rock mines, or natural aquifers. Recovery takes place by expanding the compressed air through a turbine, but the operating units worldwide incorporate combustion prior to turbine expansion in order to increase the overall efficiency of the system. Hence CAES can be regarded as peaking gas turbine power plants, but with a higher efficiency, thanks to the decoupling of compressor and turbine, and much lower overall cost. Deployment is often dependent on the availability of suitable underground reservoirs but custom-built high-pressure storage tanks can be utilised.

Kinetic energy

Kinetic energy may also be used to store energy in the form of the inertia of a flywheel. Flywheels have been used in hydro power stations with synchronous generators for many years. With the advent of advanced composite materials with high tensile strength, and the development of stable magnetically suspended bearings, flywheels may now be made with significantly higher operational speeds. All reciprocating engines contain flywheels to smooth the pulsed output of the pistons and provide stable power. Flywheels storage systems are particularly suitable for power quality control. They can provide ride-through power for the majority of power disturbances, such as voltage sags and surges, and can bridge the gap between a power outage and the time required to switch to long-term storage or generator power with excellent load following characteristics. Large, high-speed super flywheels might one day provide a means of meeting system peak demands.

Capacitors

Capacitors store energy by way of separating the charge onto two facing plates. They are widely used in electronic devices for power smoothing after rectifying. Typically, these applications require very small energy amounts. In order to increase the energy density, the so-called 'Super-Capacitors' (or even 'Ultra- capacitors', if their capacitance exceeds 1,000F) have been developed. They use polarized liquid layers at the interface between a conducting ionic electrolyte and a conducting electrode, which increases the capacitance. Super-Capacitors Energy Storage (SCES) offers extremely fast charge and discharge capability, albeit with a lower energy density than conventional batteries can provide and can be cycled tens of thousands of times without degradation.

Superconducting Magnet Energy Storage

In a Superconducting Magnet Energy Storage (SMES) device, a coil of superconducting wire allows a DC current to flow through it with virtually no loss. The current creates a magnetic field that stores the energy. On discharge, special switches tap the circulating current and release it to serve a load. To set the coil in a superconducting state, it has to be cooled down either to 4.2iK (low- temperature superconducting) or 77iK (high-temperature superconducting). Technical improvements and a better knowledge of dealing with and controlling cryogenic systems have allowed SMES to penetrate the market and compete with more common storage systems. The dynamic performance of SMES is far superior to most other storage technologies. Response times down to milliseconds are possible and the energy can be transferred very quickly. SMES are most suitable for high value/low energy applications, where the storage requirement is for less than a few seconds, with power requirements up to 1 or 2 MW.

Batteries

Batteries are the most common devices used for storing electrical energy. Traditionally they have been used for small-scale applications but there is growing awareness amongst manufacturers of the potential applications for larger scale energy storage in the context of liberalised electricity markets. As battery cells have a characteristic operating voltage and maximum current capability, battery systems normally consists of several cells, linked in series or parallel dependent on the required power and energy rating. Batteries exhibit a fast response to changes in power demand. Their efficiency varies among technologies, and also depends on the application and the operation regime. The most mature technology, flooded lead-acid (LA) batteries and valve regulated lead-acid (VRLA) batteries, have been in service in electric power applications. Nickel-cadmium (NiCd) batteries have also reached an important maturity degree.

Advanced battery technologies such as sodium-sulphur (NaS) and lithium-ion are quickly becoming commercially available. Lithium-polymer (Li-polymer) and nickel-metal hydride (NiMH), which have been developed mainly for automotive use, and metal-air, are also candidate storage media. For example, The NaS (sodium – sulphur) high temperature battery has been under development by Tokyo Power's engineering research group since 1983, and field-tested since 2001. This battery has a high energy density, high efficiency and long-term durability. Volume production started in April 2003. Megawatt size installations are planned.

Features of this battery type are:

- Three times the energy density of a lead acid battery (160kWh/m^2).
- No self-discharge and a high charge/ discharge efficiency.
- Up to 2,500 full charge/discharge cycles.
- Fully sealed, with no exhaust or emissions.
- High pulse power can be supplied for short periods.

Flow Batteries

Flow Batteries (FB), also known as Regenerative Fuel Cells or Redox Flow Systems, are a new class of battery that has made substantial progress technically and commercially in the last few years. Flow Batteries Energy Storage (FBES) systems have features that make them especially attractive for utility-scale applications. The operational principle differs from classical batteries. The latter store energy both in the electrolyte and the electrodes. Flow batteries, however, store and release energy using a reversible reaction between two electrolyte solutions separated by an ion permeable membrane. Both electrolytes are stored separately in bulk storage tanks, whose size defines the energy capacity of the storage system. The power rating is determined by the cell stack. Therefore the power and energy rating are decoupled, which gives the system designer an extra degree of freedom when designing the system. Many different electrolyte couples have been proposed for use in flow batteries. Current developments are based on vanadium redox, sodium polysulphide / sodium bromide and zinc / bromine.

Hydrogen storage

Hydrogen storage is an immature technology but envisaged as a promising means of electrochemical storage attracting huge interest and research funding in Europe and the USA particularly. In a Hydrogen Energy Storage (HES) system, the charge takes place when the electrical energy is used in an electrolyser to split water into hydrogen and oxygen. The oxygen is usually vented to the atmosphere while the hydrogen can be stored in different ways. The discharge, providing the energy release, can take place in a heat engine or fuel cell. One significant advantage of hydrogen as a storage option is that the energy storage capacity input power rating and output power rating are completely decoupled. Most aspects in the hydrogen-related technology, including generation, storage and utilisation in fuel cells, need further development.

The most severe problem that burdens HES is the low overall process efficiency. There are losses in the electrolyser, storage and heat engine or fuel cell. Technological breakthroughs will improve the efficiency, but it will still remain considerably behind other competing technologies. Despite the concerns that hydrogen arouses, hydrogen does not pose more safety problems than other fuels. Being the lightest gas, hydrogen quickly disperses into the environment in the event of leakage, making it less of a fire hazard than gasoline.

Summary on Storage Systems

Economic modelling done recently in Europe provides the following insights:

- Total system capital cost is the most important variable driver of the attractiveness of storage systems. Pumped hydro systems can be viable in certain current market environments, specifically to small-scale lower cost plants with favourable topographical conditions.
- HES systems are not yet economically viable, but expected improvements in capital cost and system efficiency will likely change this result over the 5-10 year term, in the context of current technology. This is based on electrolysis and gas engine technology and excludes fuel cells.
- A complete model of flow battery economics and viability awaits detailed operational data. The Regenesys plant in the UK was expected to provide this in the short term but this project was abandoned in December 2003.

6 Conclusions

More work is yet required to fully assess the likelihood of any of the non-conventional options discussed in this report proceeding within the ten-year time frame of the review. In the absence of any market information it is difficult to reach any opinion on the likely uptake of non-conventional sources in this time period.

In examining the various options it is necessary to acknowledge that while many of these alternatives may be technically feasible, they are unlikely to be financially viable (with the exception of conventional diesel or gas turbines) and in the absence of special circumstances (eg. direct subsidy) are unlikely to proceed in the current time frame.

Pumped storage based on the Waitakere water catchment has the potential to supply over 1300 MWh of storage capacity and may well be a potential near-term option. Peak power demand for Auckland is near 300 MW in the peak evening period. The opportunity thus exists for a 300 MW pumped storage facility utilising the Nihotupu and Huia catchment areas. Further detailed work will be required to confirm the practicability of any such option.

The secondary, but equally important consideration, is the time frame within which decisions have to be made and the upgrade and/or alternatives have to be actioned. Based upon the projected demand growth for the Auckland region (about 3% per annum), it can be expected that from the year 2009 onwards Auckland will require approximately 200 MW of new generating capacity to be commissioned every three years to maintain the 'n-1'security level.

Although the city is attached to the National Grid, the scale of demand in this one city is sufficient to require its own planning base. It can be argued that a useful step would be for Auckland to meet some of the demand from within the city environs and local resources. To this end there are certain technologies that are worthy of further investigation. These to some extent are specifically Auckland orientated, although in most cases their application may be extendable to other regions of the country.

It is our belief that the advantage of reduced losses, avoided cost of transmission, and improved energy conversion efficiency should be factored in when considering the economics of such embedded, and distributed, new generation. In this respect it can be expected that many of the smaller power station concepts promoted to the commission hydro power station and medium scale gas turbine power stations concepts promoted to the Commission will inevitably become available as their promoters deem the economics to be viable.

Beyond this basis, however, we suggest that the following four sources of energy and conversion technologies should be investigated further as in at least two cases they are very specifically Auckland orientated. These are:

- Municipal solid waste to energy conversion;
- Increasing use of gas turbine and diesel generator sets;
- Tidal current systems; and
- Storage systems including pumped water storage.

Apart from Tidal Current, all of the above are commercially available. Further detailed work on these options is required to establish feasibility and the likely direction that the electricity market will ultimately take. Uptake of these technologies will be dependent on managing the investment risks.

It is clear, however, that diversity of supply will inevitably become a key issue in examining options in support of this country's centralised grid system.

Appendix 1: Pumped Hydro Storage in the Waitakere Range: A preliminary assessment

This is an initial high-level investigation into a pumped hydro storage system for the Auckland region. Many aspects have not been covered, and further investigation is required including: impacts on Auckland's water reticulation, silting issues, RMA requirements, geological factors, capital cost and cost benefit compared with the grid upgrade.

These initial calculations show that such a system, in energy terms, is feasible and could potentially provide a useful storage option, especially if coupled with other forms of renewable intermittent generation.

The Waitakere ranges contain several sites that may be capable of providing pumped hydro storage for Auckland with the modification of existing dams and reservoirs currently used for water reticulation in the Auckland area. Two pumped storage sites have been identified. The topographic map below shows the existing reservoirs in the Waitakere range. It is believed, from a preliminary examination of the issue, that there would be little effect on Auckland's water reticulation if the scheme was controlled in an appropriate manor, although obviously more work would be needed to support such an assumption.

Two parallel reservoir systems exist in both the Nihotupu and Huia catchments. Both catchments contain upper and lower reservoirs that appear ideal for two parallel pumped storage schemes. Both upper reservoirs have volumes of 2.2Mm^3.

Potential energy of a Waitakere pumped storage scheme

The capacities of the reservoirs in question are tabulated below along with the vertical height differential and the gravitational potential energy calculations (assuming an efficiency of 70% for pumped storage).

Obviously these calculations incorporate a number of simplifying assumptions including the assumption that all the water in the upper reservoirs can be drained till nearly empty. This may or may not be possible and will depend on the design of the intake to a penstock/tunnel system and other hydrological or environmental/water quality factors of the upper reservoir.

As shown in the table overpage (ref. 7), the total gravitational potential energy storage of both systems (assuming an efficiency of 70%) is approximately 1300MWh. This, coincidentally, is the same energy that is required to

Reservoir	Capacity (m^3)	Area (m^2)	Height asl (m)	Potential Energy (E_p=mgh)
Upper Nihotupu	2200000 m^3	125000 m^2	200m	$E_p \approx$ 830MWh
Lower Nihotupu	4600000 m^3	529000 m^2	10m	
Upper Huia	2200000 m^3	189000 m^2	160m	$E_p \approx$ 470MWh
Lower Huia	6400000 m^3	503000 m^2	40m	

meet peak demand under Transpower's load curve up to the year 2015. When coupled with the ability to supply reactive power support and spinning reserve, and if proven economic, pumped hydro could become a viable storage option.

From examination of the load profile curve, the 'peaking power' required above the capacity limit is near 300MW in the evening peak period. Hence, up to 300MW of pumped storage facility seems an appropriate basis for further investigated. An example could be a 50MW to 100MW plant for the Huia catchment and a 100MW to 200MW plant for the Nihotupu catchment, or perhaps just one 100 to 200MW storage scheme on in the Nihotupu catchment.

System costs

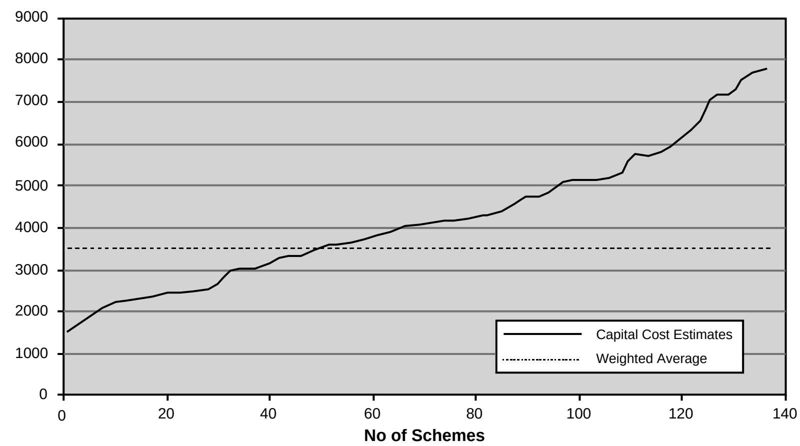
The capital cost of any Waitakere scheme is as yet unclear. However for a generic storage system the capital cost comprises the sum of two parts; one is related to the storable energy; the other depends on the peak power that the storage must deliver (as controlled by the charge-discharge control system) in accordance with demand requirements.

Waitakere has the advantage that the storage reservoirs are part of the existing infrastructure, meaning the capital cost of the central store is likely to be near zero (assuming only minimal modifications to the existing dams). Thus it is likely that the Waitakere scheme will mirror a more conventional hydro power station cost. One disadvantage, however, is the horizontal distance between the two reservoirs, which could affect the cost of discharge and overall efficiencies.

Hydro costs have a large variation. The figure below shows this, giving a range for installed costs from NZ$1500/kW to over NZ$8000/kW with an average of around NZ$3500/kW (ref. 8).

Most pumped storage schemes throughout the world have an underground station. This may add/subtract to the cost on a case-by-case basis. As mentioned above, the horizontal distance between the lakes means penstocks would be very costly unless the station was moved closer to the upper reservoir. One option would be to instead use underground tunnels, not dissimilar to a smaller version of Manipouri Power station. In this instance the powerhouse would be located underground near the bottom reservoir with a long penstock tunnel. The reason for this would be to utilize fast spinning reserve capacity which required a low volume of water to be moved after the power station turbines.

To get some idea of capital cost, the second tailrace tunnel for Manipouri cost $212Million and is 10km long and 10 meters in diameter. A proposed Nihotupu Pumped Storage scheme would be around one third to one quarter the size of Manipouri.



Appendix 2: Energy Source Summary Table

The table below summaries particular special factors for the major energy resources, and the commercial, externality and regulatory issues.

Fuel Type	Commercial issues	Externality issues	Regulatory issues	Special Factors
Bioenergy	Availability/cost of fuel need for waste disposal? Use for heat on or off-site? Principally a heat source	Air and noise emissions	Solution for environmental problems 40 MWth installed annually (for timber drying) Scale issue – too small for viable electricity generation	Growing source of wood, log exports produce waste, competition for fuel fom garden centres Unlikely to be investment in NZ in large integrated wood processing facilities
Wind	Proximity to the network Hydro system back-up Cumulative capacity constrained (20% of network load) Does not solve capacity constraint	Area of outstanding natural beauty? Noise and visual impact access to site	Shared benefits ELBs can own unlimited renewable capacity Can you connect into the network at no greater cost than the national grid?	NZ is a small, long narrow island, in roaring 40's, long coastline. Hydro system back-up opportunity favours wind.
Hydro	Water priority for generation is secondary to its use for irrigation Opuha irrigation was not bankable without generation District water supply schemes is an area of potential – dam outlet & pipeline turbines, retrofit options	Minimum flow in natural water courses Wild river preservation Paternalism – regional strategic growth - parochialism	Water allocation – no value placed on water Long & difficult consenting process – expected that only 10% of potential could be realised for this reason. Excluded under current renewable definition?? Sterilised resource by water conservation orders NB Only 20-30 MW available with irrigation??	Climate impacts generally countrywide, irrigation needs Cultural sensitivity to mixing waters Water supply schemes match daily demand but not seasonal
Fossil fuels	Fuel cost Ability to respond to peak demand signal Ability to parallel with the network Comparatively secure fuels	Noise and air emissions Co-firing with biofuel introduces renewable element	Existing use provisions enable some type of generation Local air quality plans are a potential spoiler Gensets may be portable assets DG is an easy target	Uncertain gas market dynamics, substantial increase in gas price likely Kyoto ratification

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