Distributed Generation on Rural Electricity Networks – A lines company perspective

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ABSTRACT

A number of electricity assets used in rural New Zealand yield a very low return on investment. According to the provisions of the Electricity Act 1992, after 01 April 2013, lines companies may terminate supply to any customer to whom they cannot provide electricity lines services profitably.

This research was undertaken to assist the policy makers, lines companies, rural investors on the viability of distributed generation in a rural setting from the point of view of the lines company and the investor as well as to provide recommendations to the problem areas.

A dynamic distributed generation model was developed to simulate critical distributed generation scenarios relevant to New Zealand, such as diverse metering arrangements, time dependent electricity prices, peak shaving by load control, peak lopping by dispatchable distributed generation and state subsides, which are not addressed in commercial software.

Data required to run the model was collected from a small rural North Island sheep and beef farming community situated at the end of a 26km long radial distribution feeder. Additional operational data were also collected from the community on distributed resources such as solar hot water systems.

A number of optimum distributed generation combinations involving a range of technologies under different metering arrangements and price signals were identified for the small and the medium investor. The effect of influencing factors, such as state initiatives and technological growth, on the investor and the lines companies were discussed. Recommendations for future implementation in order to integrate distributed generation on to rural networks were also given.

Several key research areas were identified and discussed including low cost micro hydro, wind resource assessment, diversification of the use of the induction generators, voltage flicker and dynamic distributed generation techno-economic forecasting tools.

Acknowledgements

No matter what work experience an international student possesses, it is always a challenging task to undertake academic research in a foreign county immediately upon arrival. Two people were influential in facilitating my task; my supervisor Associate Professor Ralph Sims and Mr. Alister Gardiner of Industrial Research Limited Christchurch.

Associate Professor Ralph Sims not only provided thorough advice and guidance throughout my research but also organized some healthy industrial forums to enable my postgrad colleagues and I to align our work with practical realities. I gained immensely from these forums and hence my first thanks is due to Associate Professor Ralph Sims.

Mr. Alister Gardiner the head of the electro-technical division of Industrial Research Limited led me to very important technical issues on New Zealand utilities, which I managed to grasp quickly and hopefully, propose solutions to some of the problem areas. Mr. Gardiner was also instrumental in proving the necessary hardware for my research through his organization, without which my research would have ended up with dull "desk research." So many thanks to Alister and his team.

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My thanks is also due to wonderful residents of Totara Valley for allowing me to visit their farms to install equipment and collect data. I believe that I have done justice to their cooperation and hospitality by coming up with solutions through my research.

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I dedicate this book to my wife Dileepa and my two young children Dulani and Samitha.

Nihal Jayamaha
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Massey University,
New Zealand

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Thesis Amendments

Some clarifications/amendments have been incorporated in response to examiners' comments. These appear opposite the relevant pages.

An errata is supplied at the end of the thesis.

Executive Summary

I. INTRODUCTION & BACKGROUND

Rural electricity supply is often characterised by long distribution lines and higher proportion of transformers than in urban areas. The quantity of energy conveyed is generally low due to dispersed population densities. In order to realise the required rate of return on distribution assets invested in rural areas, lines companies have to charge rural customers a higher $/kWh tariff for the electricity lines services. However, to date, most lines companies have been providing electricity services to rural customers at cross-subsidised rates, from urban customers. According to the provisions of the Electricity Act 1992, after 1 April 2013 a lines company can terminate its services to any customer to whom they cannot provide electricity lines services profitably. Thereby some rural customers face the risk of either having to pay very high line charges or loose their electricity supply.

Although stand alone remote area power systems and mini-grids are an option for rural communities who may become affected, staying connected to the grid while making use of local energy resources is a preferable option, provided economics allow. This is due to several benefits including better utilisation of renewable energy resources, greater supply reliability and improved voltage profile.

This research project was undertaken to provide analysis for policy makers, lines companies and rural investors on the viability of distributed generation in a rural setting and to provide recommendations concerning problem areas.

Although several commercial software packages are currently available to study the performance and economics of grid connected distributed generation systems, these are not capable of critically analysing distributed generation issues relevant to New Zealand. In particular such issues as

- impacts of diverse metering arrangements;
- time dependent electricity prices;
- benefits of peak shaving by load control and peak lopping by dispatchable distributed generation; and
- the effect of state subsidies;

are not addressed in the commercial software. For this reason, a dynamic distributed generation model was developed to simulate the above scenarios. In developing the model, an effort was made to include generic distributed generation scenarios that would be valid to the whole of New Zealand and not just to a given rural community.

II. METHODOLOGY

Data was collected from Totara Valley, which is a small rural North Island sheep and beef farming community situated at the end of a 26km long radial distribution feeder and used as a case study for several Massey University studies. The primary data collected for this research were the community demographic data, electricity supply and distribution data, real time load data, solar hot water temperature and flow data, photovoltaic data (grid connected), solar irradiation and ambient temperature data. Secondary data required for the model was collected from a variety of sources including Massey University research studies and publications.

In order to realize economies of scale, the metering of a single farm was assumed to be made through the secondary side of its dedicated transformer. Such metering was actually implemented on 3 transformers in the case study community, with a view to implement it for commercial purposes at a later point in time. It was observed that each transformer dedicated to a single property farm distributes electricity to several installation control points such as the farmhouse, cottages, woolshed, freezer shed and the workshop.

Three specific community scenarios were simulated using the model for different distributed generation (DG) and metering configurations. These were;

- Individual farm based DG applications
- Small community based centralised DG applications, and
- Medium community based centralised DG applications.

The size of the small and medium communities, in terms of the number of residential connections, was 32 and 50 respectively. Three metering configurations were also simulated:

- net metering,
- time of use gross import/gross export metering; and
- separate generation/load metering.

In addition, in cases where specific demand side responses are made in response to price signals from the lines company (e.g. operation of a dispatchable DG unit during critical peak periods), it was assumed that there would be a separate, ripple-activated meter to determine the firm capacity/energy supplied to the lines company. Although the computer model was designed to accommodate peak shaving through customer initiated load control as a demand side response, this was not simulated as it was not possible to identify loads of significant magnitude within the case study community.

III. Observations

Micro-hydro turbine

The model outputs showed that from a pure economic standpoint of the investor, only low cost micro hydro technologies would be economical for individual farm based applications. It was also observed for the micro hydro system, as simulated, that net metering was marginally more advantageous to the investor than gross import/gross export metering because of the steady flow of water (hence energy supply) all year round. The relatively low cost micro hydro unit derived its economic advantage through a very simplified electro mechanical technology that involves an induction generator and a reverse engineered water pump.

Small wind turbines

Small wind turbine generators could become acceptable in individual farm based applications only if the state subsidies for wind energy projects were provided, the site had a wind regime in excess of 7 m/s, and the investor also appreciated the social values of wind energy investment. For example if a zero interest loan was made available to finance a small wind project, a wind turbine generator was installed on an 8 m/s site and the farm load was net metered, then the farmer would have an incentive to opt for a wind turbine of 7 kW rated capacity, rather than a smaller one.

The simulations indicated that net metering is less attractive than gross import/gross export metering from a lines company perspective, but would only become a commercial threat in the shorter run if the state subsidised wind projects substantially to encourage implementation or if the cost of the system was reduced.

For community scale centralized applications, given a good wind resource availability, the economic viability of a small wind turbine was found to be dependent on three broad factors;

- whether the generation is separately metered or gross import/gross export metered (for payment purposes)
- state subsidies available and
- the size of the wind turbine generator.

The level per kilowatt of state subsidies required for community wind projects was found to be considerably less than for individual farm based applications, with larger wind projects requiring lower levels of subsidies. For this reason it was observed that, with the appropriate level of subsidy, community scale projects would enable larger capacity wind projects to be realised. The simulations also indicated that the capacity contribution made by wind turbine generators during critical peak periods would of value to both lines companies and investors. However due to the intermittent nature of the wind resource, the value would be of advantage only if the lines company is facing a capacity problem on a more regular basis.

Diesel generation

Simulations also suggested that the use of a diesel standby generator for any form of demand side response (either to take advantage of time of use tariffs or economic incentives provided by line companies for peak lopping) is not economical for individual farm based applications. However, simulations showed that peak lopping could become economical if low cost technologies are used, such as supplying firm capacity through an induction generator being driven by a diesel engine. The induction generator is attractive for small applications if a motor and its inter-connecting switchgear (starter, circuit breaker etc.) had previously been installed for some other economic activity and could be used with minor modifications.

The simulations indicated that the use of a diesel generator in excess of 50 kW for peak lopping, which is only realisable for community scale applications, is a very viable investment option. The larger the installed capacity of the generator the greater the return on investment.

Hybrid systems

Wind diesel hybrids were found to be more profitable than diesel only provided there is some form of state subsidy available for the wind energy component of the project. The simulations also showed that if subsidies are too great they would give lines companies an opportunity to exploit its monopoly position and reduce the rates they currently pay for firm capacity/energy supplied. It was assumed that the lines company would be willing to pay a fee as an annuity (i.e. a payment made every year) that is equal to the avoided marginal cost of capacity augmentation, after deducting a 10% margin to administer the payment scheme. If the 11 kV feeder to the community gets overloaded, it was found that a lines company could afford to pay up to $ 120.00 for each kW of capacity provided during the network overload periods.

Other dispatchable generation units

Simulations also indicated that small scale pumped hydro or a battery (deep cycle lead/acid) storage systems of the order of 15~18 kW would not be economical to provide firm capacity.

Solar systems

Application of photovoltaic (PV) systems was found to be uneconomic at current costs for PV panels, even though they have already been installed at Totara Valley, though this was for convenience rather than to determine an optimum system.

Analysis of real-time data on the installed solar hot water system suggested that it performs well in the summer and autumn (e.g. 27% efficiency in March), but diminishes in winter and early spring when the home occupants use their wetback stove for heating. The solar hot water system was also not designed to cater for the hot water needs of the laundry, which uses a separate electric hot water cylinder. Application and operation of a solar hot water system under such circumstances result in poor financial return on investment with only two permanent residents.

IV. RECOMMENDATIONS

In making recommendations on distributed energy related issues, an attempt was made to accommodate and reconcile the interests of the three key stakeholders; the investor, the lines company and the state.

A potential investor's lack of understanding in order to evaluate different distributed energy options was identified as the most critical problem. This causes small-scale investors to build an extra risk premium which undermines the uptake of DG, because distributed energy projects currently do not generate adequate cash flows to cover the risks. It is recommended that in addition to advising potential investors on the various renewable DG options, they should also be encouraged to select the best renewable energy option to suit the relevant circumstances. For this purpose, it is necessary to list the key decision variables and illustrate how those affect the decision outcome (i.e. the optimum technology combination). In addition to renewables, communities should also be advised on possible opportunities to provide firm capacity (or firm energy) to the lines company and the technology options available to achieve this.

The social benefits of rural distributed energy projects is important for rural investors to consider to create a utility (satisfaction). This would bring a salutary effect in influencing their investment decisions. Any social benefits should be quantified and made as objective as possible.

Establishment of a demonstration community owned, grid connected, distributed generation scheme is a strategy that could be implemented to educate the public on the benefits of renewable energy. Only well informed citizens would be able to best utilise any subsidies in order to maximise personal investment objectives. This in turn would serve to meet the state's objective of maximising the uptake of renewables at the lowest cost.

At current costs state subsidies would be vital to maximise the uptake of small-scale grid connected renewable DG applications.

From a lines company perspective, it is myopic to view DG as inconsequential. Small-scale renewables, technological growth and regulatory control can cause risk to lines companies unless they appreciate the benefits of DG and device plans to manage it. As a general rule, it is recommended that lines companies accommodate small scale DG with minimum charge for inter-connection. As DG is introduced to the network, lines companies can commence gradually removing any cross-subsidies built into rural connections so that part of the foregone revenue owing to rural DG projects could be recovered from rural customers who benefit from DG. It also provides an incentive for rural entrepreneurs to undertake distributed energy projects. At a later point in time assuming an increase in the uptake of DG and lowering of the technology costs, lines companies could introduce inter-connection charges for new DG projects.

For a lines company facing capacity problems, as an alternative to capacity augmentation, it can pay an annuity to DG owners to provide firm capacity/energy at the rate of avoided marginal cost of capacity investment. A lines company could use its monopoly position and reduce this annuity over time, depending on other factors such as carbon credits or subsidies for renewables. A prudent way a lines company could handle community scale centralised DG projects would be to stipulate metering systems that do not directly affect their revenues and device tariffs, which take into account capacity drawn during critical peak periods.

Low cost micro hydro, diversification of the use of the induction generators, voltage flicker on weak distribution networks due to wind turbine generators (and methods of minimising it including the possibility of using wind/diesel hybrids), wind resource assessment (also making wind data available through a geographic information system), devising accurate DG performance producing and economic forecasting tools were the key areas identified as future research areas.

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CHAPTER 1

Introduction

1.1 ELECTRICITY IN NEW ZEALAND

New Zealand is a small country with a land area of 270,535 sq km and a population of 4 million. The country consists of two large islands; North Island and South Island, plus several smaller ones of which Stewart Island being the largest. North and South Islands are separated by the 32km wide Cook Strait. About two thirds of households as well as major industrial and commercial institutions are in the North Island of which the majority are located in and around the Auckland region.

Electricity generation in New Zealand has traditionally been hydro based. Even today, annual contribution from hydro generation amounts to 60% -70% depending on hydro inflows. Major hydro stations are located in the lower half of the South Island. This is one reason why New Zealand's transmission network is associated with long transmission lines including a 350kV DC transmission line linking Benmore Hydro Power Station in the South Island with Haywards Substation in the North Island (located close to Wellington, the capital of New Zealand). This conveys energy flows from the South Island to the North Island across the Cook Strait. New Zealand's electricity grid is depicted in Appendix A.

Approximately 30-35% of the generation comes from thermal power stations while the rest comes from geothermal, the two wind farms in the lower North Island that were installed in the late 1990s and some biomass plants and cogeneration plants. The contribution of wind and biomass power compared to geothermal is small. Much of new generation capacity to date has been around turn-key gas fuelled combine cycle power projects utilising natural gas from New Zealand's offshore Maui gas field and other sources. Critically low hydro storage capacities were reported in 1992, 2001 and 2003 suggesting that the country is overly dependent on hydro and that additional generation capacity ought to be installed as soon as possible, in keeping with the increase in energy demand that accompanies the economic growth of the country (Hooper *et al* 2002).

1.2 AN OVERVIEW OF THE ELECTRICITY INDUSTRY TODAY

Electricity industry in New Zealand is no longer a state monopoly. In order to promote private sector participation sweeping industry reforms have been launched by the government since 1985. Private sector participation in all but the transmission of electricity is commonplace in New Zealand now, as shown in Figs. 1.1 through 1.3.

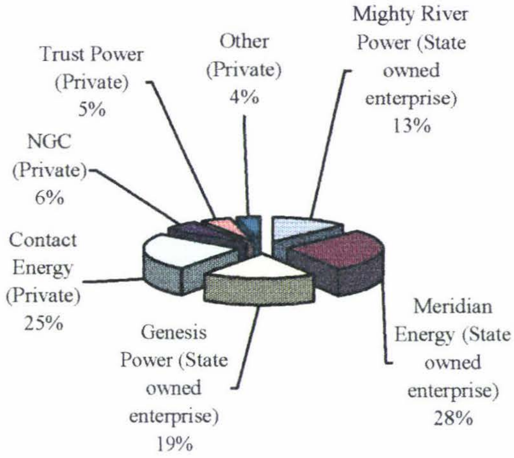

Fig. 1.1: Generation stake in New Zealand as of January 2000 out of a total installed capacity of 8378 MW

(MED, 2000)

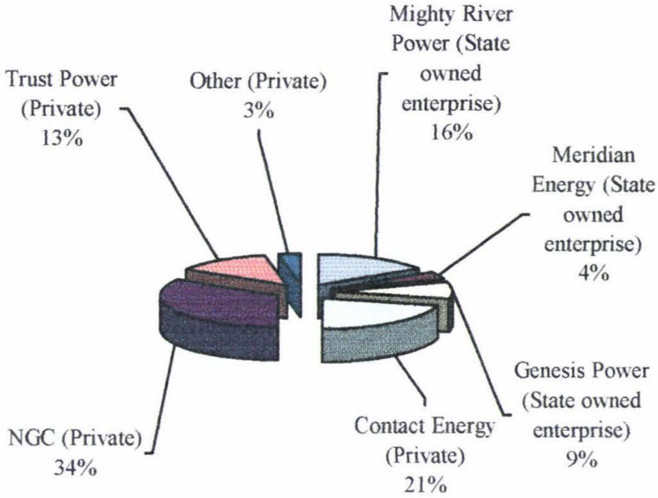

Fig. 1.2: Electricity retailing stake in New Zealand as on January 2000 out of a customer base of 1.7 million..

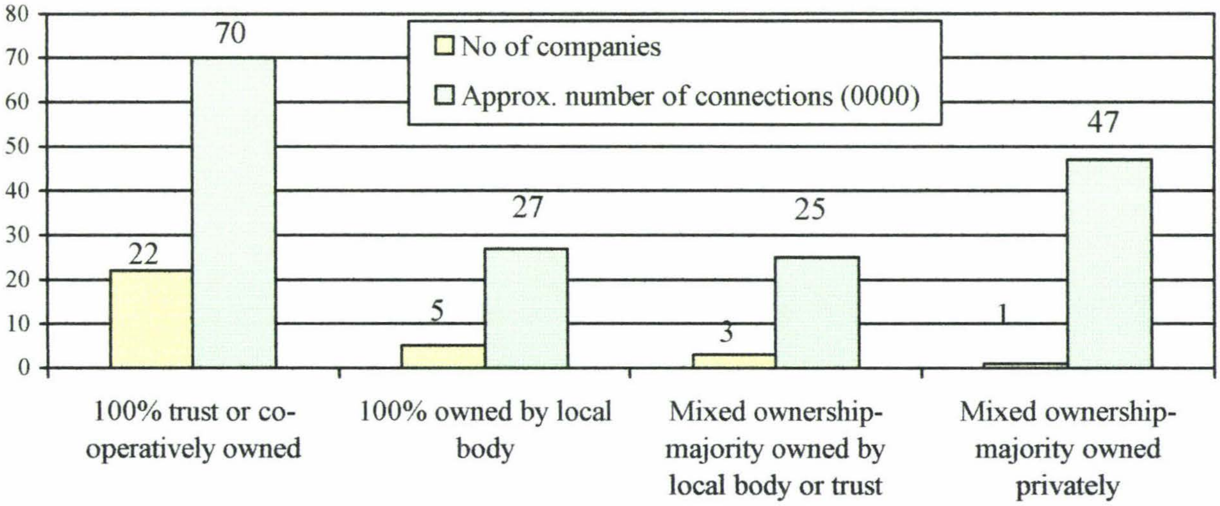

Fig. 1.3: Electricity distribution stake in New Zealand as on January 2000 *(MED, 2000)*

1.2.1 Issues pertaining to distribution companies in New Zealand's deregulated electricity industry

In New Zealand, as in other countries, the conventional model of the electric power industry is characterised by large-scale central generating stations with transmission and distribution systems conveying power over long distances having evolved overtime time with the customers.

Large-scale central generating stations will continue to meet shortfalls in New Zealand energy demand in the foreseeable future. However, the lobbying of pressure groups on environmental concerns pertaining to the new and existing central generating stations is ever increasing. In addition poor power quality to customers towards the end of a distribution feeder has resulted in the industry seeking new technological solutions such as fast response voltage compensation devices. Power quality was not so much a problem 20 years ago when most loads were electric motors and light bulbs. Customer expectations are now higher in that not only do they expect electricity at a competitive price but they also expect a good quality service with minimum impact on the environment. The state has a direct interest on the depletion of natural resources (e.g. natural gas), the harmful effects on the environment as well as the welfare of the citizens. It is seeking ways and means of promoting energy efficiency and renewable generation under the National Energy Efficiency and Conservation Act (2000). These stakeholder interests have to be accommodated by a distribution company in formulation of its corporate plans.

Distributed resource technologies, in particular distributed generation, are increasingly seen as one possible solution to all of the above problems and more. Distributed resources are small-scale electricity generation, storage and control systems located on or near the customer-end of a utility network. Distributed generation (DG) is a distributed resource technology involving generation of electricity from a primary energy source (Sen, 2002).

Energy generation, storage and power control devices can be installed at the customer site to ensure adequate power quality for critical loads. Small-scale generators and larger energy storage devices can alleviate pressure points on the distribution grid, while precluding the need for new central generation and transmission to accommodate uncertain load growth and market share. Demand-side management and controls can also help cushion the network capacity against the need for capital-intensive expansion (Sen, 2000).

Due to low population densities, supplying electricity to some rural areas in New Zealand through conventional methods require considerable commitment of assets such as long medium voltage distribution lines, a large number of distribution transformers (virtually one transformer per customer), for which realisation of financial returns would be a difficult proposition. The legislature has correctly identified this position and has passed laws that make distribution companies or lines companies as they are called in New Zealand, absolved from supplying electricity to unprofitable areas after 01st April 2013.

1.2.2 Possible considerations for issues faced by distribution companies

New Zealand is blessed with an abundance of wind resources (Wellington, Wairarapa and Manawatu regions being good examples), many water streams and a reasonable amount of sunshine from the top of the North Island to the bottom of the South Island[1]. Therefore use of distributed energy resources that incorporate clean technologies looks promising from the nation's perspective. There is insufficient research evidence however to ascertain whether distributed energy resources as a new technology would be a viable option for the year 2013 problem.

Since lines companies may no longer be able to serve some rural customers profitably through conventional means, they may wish to know whether new technology involving distributed resources could be used as a strategic option in order to continue serving less profitable customers. A decision to terminate the supply to a rural customer[2] is the last resort a lines company would adopt since most lines companies have actually evolved from historic electorally established public electricity supply authorities which had a direct and excellent vendor-customer relationship as a service provider.

1.3 THE HISTORICAL BACKGROUND

Generation of electricity in New Zealand for commercial purposes dates back to 4th August 1888 when Reefton Electrical Transmission of Power and Lighting Co. Ltd's 20 kW

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[1] *Although the number of sunshine hours per year drop from around 2450 at Blenheim to 1600 at Invercargill due to change in latitude, the daily average solar energy variation is not very significant; with 4.6 kWh/m^2 at Blenheim to 4.0 kWh/m^2 at Invercargill (Clark, 1999).*

[2] *Although 15% of the New Zealand's population belongs to the rural sector, it does not mean at all mean all rural areas are uneconomical to serve by a utility. For example, about 15% of the rural population is concentrated in so-called rural centers, which are defined as communities with a population between 300 to 999, which is by no means a small customer base (Statistics NZ, 2002).*

Reefton Power Station, sited on the bank of Inanguha River, started its operation by lighting 50 carbon filament lamps at Kater's Oddfellows Hall.

Since then generation, transmission & distribution progressed gradually and in the first 30 years the state, local bodies and private enterprise all jockeyed for position in providing services. However it was the Electric Power Board Act passed in 1918 that provided the fundamental framework for the electricity generation, transmission and distribution in New Zealand. Once the Act came into force, private sector participation in this vital service industry disappeared (Rennie, 1989).

The start point of electricity industry reforms dates back to mid 1980s during which time electricity generation and transmission were amongst the responsibilities of a government department, the Ministry of Energy. The ministry was also responsible for policy advice and regularity functions. Local distribution and supply (retailing) were the responsibility of sixty-one electricity supply authorities (ESAs). These were electorally oriented, statutory monopolies. Inefficiency and absence of customer choice were the main features of these ESAs (MED, 2002).

Meanwhile in the mid 80s, there was a global outcry for structural adjustments of state operations in virtually all capitalist societies for reasons such as waste and inefficiency experienced in state owned enterprises (SOEs) often coupled with political interference. New Zealand was of course no exception and any potentially commercial government operation were converted into a corporate form (Rosenberg, 1999), signaling the privatisation drive of the electricity industry. The reason for corporatisation, as cited by the government, was to give freedom to perform a public enterprise as a commercial enterprise and thereby create responsibility and accountability for its operations (MED, 2002). Recent key developments occurring since then are covered in the next section.

1.4 KEY DEVELOPMENTS INCLUDING FORMATION OF ACTS AND REGULATIONS

Electricity Corporation of New Zealand Ltd (ECNZ) was set up in 1987 as a company, under the State-Owned Enterprises (SOE) Act, to own and operate the generation and transmission assets of the Ministry of Energy. In April 1988 Transpower New Zealand

Limited[3] was set to run the transmission network as a subsidiary of ECNZ, which became solely a generator. In July 1992 Energy Companies Act 1992 came into effect which provided for the corporatisation of the ESAs. Diverse ownership patterns resulted but trust ownership was the most favoured.

The Electricity Act 1993 that came into effect on 01 April 1993 was another key turning point. This act removed distributors' statutory monopolies and the obligation to supply to new connections. However the provisions of the act required lines services to continue their supply of electricity to places that they were earlier supplying up until 01st April 2013 (20 years). The act also provided for information disclosure of the natural monopolies; Transpower and lines companies, which is now fully covered under the statue Electricity Regulations 1999 (e.g. sections 23 and 24 of the act provides for disclosing the pricing methodology).

A competitive wholesale electricity market was established in October 1996 through a multilateral contract – the New Zealand Electricity Market (NZEM). The firm M-co was contracted to act as Market Administrator, Clearing Manager and Pricing Manager, Transpower took the roles of Scheduler and Dispatcher (MED 2000).

The Electricity Industry Reform Act 1998 came into effect in July 1998. The act required corporate separation of lines and energy businesses to be achieved by 1 April 1999 and full ownership separation no later than 31 December 2003 (the full separation was in fact completed more quickly than expected).

The Electricity Industry Bill 2000 was enacted on 7 August 2001. This bill amended four statutes; the Ministry of Energy Abolition Act 1989, the Commerce Act 1986, the Electricity Act 1992, and the Electricity Industry Reform Act 1998. Electricity Industry Reform Act as amended allowed lines companies to own distributed generation (DG) up to 2% Network's maximum demand or 5MW, whichever is greater and unrestricted distributed generation provided that the source of generation is a New Renewable Energy Source & that the activity is carried out by a separate company having limited affiliation.

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3. *The author shall also use the shorten name Transpower, to refer to Transpower New Zealand Limited.*

1.5 PROBLEM IDENTIFICATION

The crucial issue is that after April 2013 some rural customers could face the risk of either having to pay very high line charges or lose the electricity supply serviced through the network, at the hands of their lines company.

The first impression of distributed generation does not apparently look promising from a lines company perspective, as it reduces the units of electricity conveyed over the lines company assets and a hence lesser quantity of sales volume to recoup the expected returns. However, in a deregulated market electricity is a commodity that carries a time value, as signalled by the price at a given time of the day. The price will reflect the going price for energy at the spot market as well as what a lines company charges for delivery of electricity at that time of the day. There exists opportunities for customers, third parties and lines companies to take advantage of the price signals to make distributed resources a viable technology for all concerned.

Standalone generation is certainly an option for rural communities who are likely to become affected by 2013 problem. However DG as opposed to standalone generation has several other benefits such as better utilisation of resources from a macro perspective (imagine a community having a water stream with a potential to generate 100 kW having to be scaled down to 5 kW due to low community load demand!), higher reliability, improved voltage profile, greater green benefit and so on. Hence a DG solution is more beneficial not only from a community's point of view but also from the nation's view point.

The stage is set for policy makers, utilities (in particular lines companies) and the research community to identify technical and non-technical problem areas and propose solutions so that lines companies can continue to serve New Zealand's rural communities, who provide the backbone to the agricultural economy of the country.

Potential investors, policy makers and experts are confronted with several problem areas such as choosing the appropriate technology for a given situation, choosing the size/capacity required from each technology, choosing the optimum generation dispatch and demand side strategies, and identifying policy changes that are necessary for the uptake of distributed resources. Solutions to these problems can only be proposed through

This research does not provide recommendations to the lines companies as to what they should do with unprofitable lines after 2013. What the research investigates and analyses is the extent to which distributed generation (DG) on rural lines could affect lines companies today and in the future.

If DG applications are rare due to poor financial viability, then obviously lines companies do not have to make their post 2013 decisions or any other strategic decision based on DG, as they pose neither opportunity nor threat to the company.

Therefore, in the opinion of the author, it is important to analyse the financial viability from an investor's perspective (the investor can be a private individual, a collection of individuals or a lines company) and the circumstances that cause DG to become financially viable. A good portion of the research was thus directed to this cause.

The research also analysed in detail the relationship between DG and the foregone revenue of a lines company, the strategies to minimise the revenue losses and maximise network capacity support opportunities which provided a valuable insight for lines companies in projecting their sales forecasts, tariffs and network upgrade investments.

a systematic study and analysis from a multi-disciplinary perspective. The above issues were addressed in order to meet the following objectives.

1.6 OBJECTIVES

The overall aim of the research was to model different distributed generation applications with a view to predict the performance and economics at an acceptable level of certainty and to study rural distributed energy resource application benefits from a lines company perspective, taking into account the interests of the other key stakeholders.

The specific research objectives were as follows.

1.6.1 To study different electricity metering and distributed generation configurations.

1.6.2 To develop a "generic distributed generation model" that can be used to search the optimum distributed resource combination, for a given situation (in a rural context or otherwise).

1.6.3. To identify controllable and uncontrollable loads in a rural community for load profile improvement.

1.6.4 To simulate different distributed generation control regimes involving both renewable & non-renewable sources to ascertain how they affect investors and lines companies.

1.6.5 To postulate distributed generation decision rules (e.g. when to start a standby generator and when to stop) that could be implemented with a view to achieve predefined decision outcomes such as obtaining the required return on investment, improving the network load factor, lowering life cycle costs of investment and reducing network operator's investment costs.

1.6.6 To recommend optimum distributed generation configurations suitable for rural New Zealand communities. The optimum configuration is the configuration that best accommodates investment objectives of the entrepreneurs (as a community) and the network operators.

1.6.7 To identify issues that act as barriers to the viable implementation of distributed generation in a rural context.

1.6.8. To gain a practical experience of different hardware used in distributed generation solutions.

1.7 THE STRUCTURE OF THE THESIS

The remainder of the thesis is chapterised as follows:

Chapter 2 covers the literature review that examines the current state of knowledge of the research area.

Chapter 3 describes the technological and economic aspects and the future scope of PV modules, wind turbines, small hydro units, pumped hydro units, fuelled generator sets and storage batteries. These distributed resources are central to the distributed generation system modelling covered in chapter 6. A brief review on solar hot water systems and fuel cells are also included in this chapter.

Chapter 4 describes how load profiles could be developed in respect of an individual customer as well as a group of customers, using historical load research data. Customer load profile is an input data file that is required to run the distributed generation computer program described in chapter 6.

Chapter 5 describes how necessary data was gathered.

Chapter 6 describes how the models and algorithms were constructed, based on which a computer program was written.

Chapter 7 depicts the descriptive statistics on the data collected. These statistics enabled technical analysis to be conducted and formed the basis for the model.

Chapter 8 analyses the simulation results of different distributed generation combinations for applications at individual customer basis as well as the community basis.

Chapter 9 gives recommendations for future progress.

Chapter 10 sums up the key findings and the scope for further research.

Chapter 2

LITERATURE REVIEW

2.1 THE TRADITIONAL OUTLOOK OF ELECTRICITY GENERATION, TRANSMISSION AND DISTRIBUTION

Chiefly due to economic and geographic reasons, electricity generation, transmission and distribution have traditionally been associated with large generating units, long transmission lines and large utility companies.

The economic reasons for the above situation are associated with economies of scale. Economists attribute four key reasons as to why large-scale production and distribution of electricity (for that matter any good or service) yields economies of scale (Pappas, 1987).

- Large firms are more productive with their labour by way of selecting the right man for the right job (division of labour).
- In respect of a capital intensive operation such as production and reticulation of electricity, technological factors play a major role in that large-scale operation typically permit the use of highly specialised equipment, as opposed to the more versatile but less efficient machines and other capital equipment used by smaller firms.
- Even for a given base technology (say hydro), productivity of equipment frequently increases with size very much faster than the cost. For this reason 500 MW of electricity generation via a single generator costs considerably less than say five hundred 1 MW power stations.
- Large firms typically have greater access to capital markets and can acquire funds at lower rates.

Geographic reasons for the traditional approach are usually associated with hydro power stations and their remote distance from major load centres. Locations suitable for large hydro power stations are usually situated well away from major load centres. This means that large power stations have to be complemented with very long high voltage transmission lines[1] conveying electricity to the substations near the load centres.

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1. *Since available power = voltage*current * power factor, and physical limits do exist in respect of the size of cables and other transmission equipment that could be economically used, large quantities of power over long distances can only be transmitted at high voltages to minimize costs and transmission losses.*

Title to the section 2.2.1 should be changed to "Distributed Energy Systems Involving Electricity Generation, Storage and Control".

2.2 DEFINITION OF DISTRIBUTED ENERGY SYSTEMS

Although there is no universal definition for distributed energy systems, the most widely used definition of distributed energy systems is that *"Distributed energy systems are local small scale systems for energy conversion, production and storage as well as related services (Alanen, 2003)."* The energy production cover electrical power, heat or cold and may be produced from a primary energy source, which may be either a renewable source (e.g. solar, wind) or a non-renewable source (e.g. fossil fuel). The output of a distributed energy system can either be independent or connected to a local electrical or heat network (Appendix – B).

2.2.1 Definition of distributed resources

Distributed resources[2] are a subset of distributed energy systems and covers electrical power devices only. Distributed resources are defined as modular electrical power devices for the supply, storage and control of electrical power located on or near the retail or customer-end of an electrical network (Sen, 2002). Distributed resources cover distributed generation systems (section 2.2.2), energy storage devices as well as demand side management electronics.

2.2.2 Definition of distributed generation

There seem to be a slight confusion over what scope of demand side activity should embrace a definition of distributed generation (DG). The popular definition is that *"Distributed generation is small-scale electrical power generation at or near the load site, which is either interconnected to the utility distribution system or connected directly to the customer's load or both (Foster, 2002)"*.

Combined heat and power (CHP) systems do fall into the definition of DG due to electricity generation at the load site where the heat is also used normally used.

2.3 THE POSITION OF DISTRIBUTION GENERATION IN THE POWER SYSTEM ARCHITECTURE

The business of electricity production and reticulation[3] by nature is highly capital intensive. As evident from the company balance sheets of the main New Zealand generators, Transpower and the lines companies, a major portion of their capital is

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[2] *Some authors refer to distributed resources as "distributed energy resources," which is a little confusing. The actual energy resource can considered to be the primary energy source (e.g. wind, solar etc.).*

[3] *Reticulation covers both high voltage transmission and distribution of electricity.*

invested in fixed assets with the objective of generating the required revenue. Fig. 2.1 illustrates the framework of New Zealand's power system, along with who owns what fixed assets.[4]

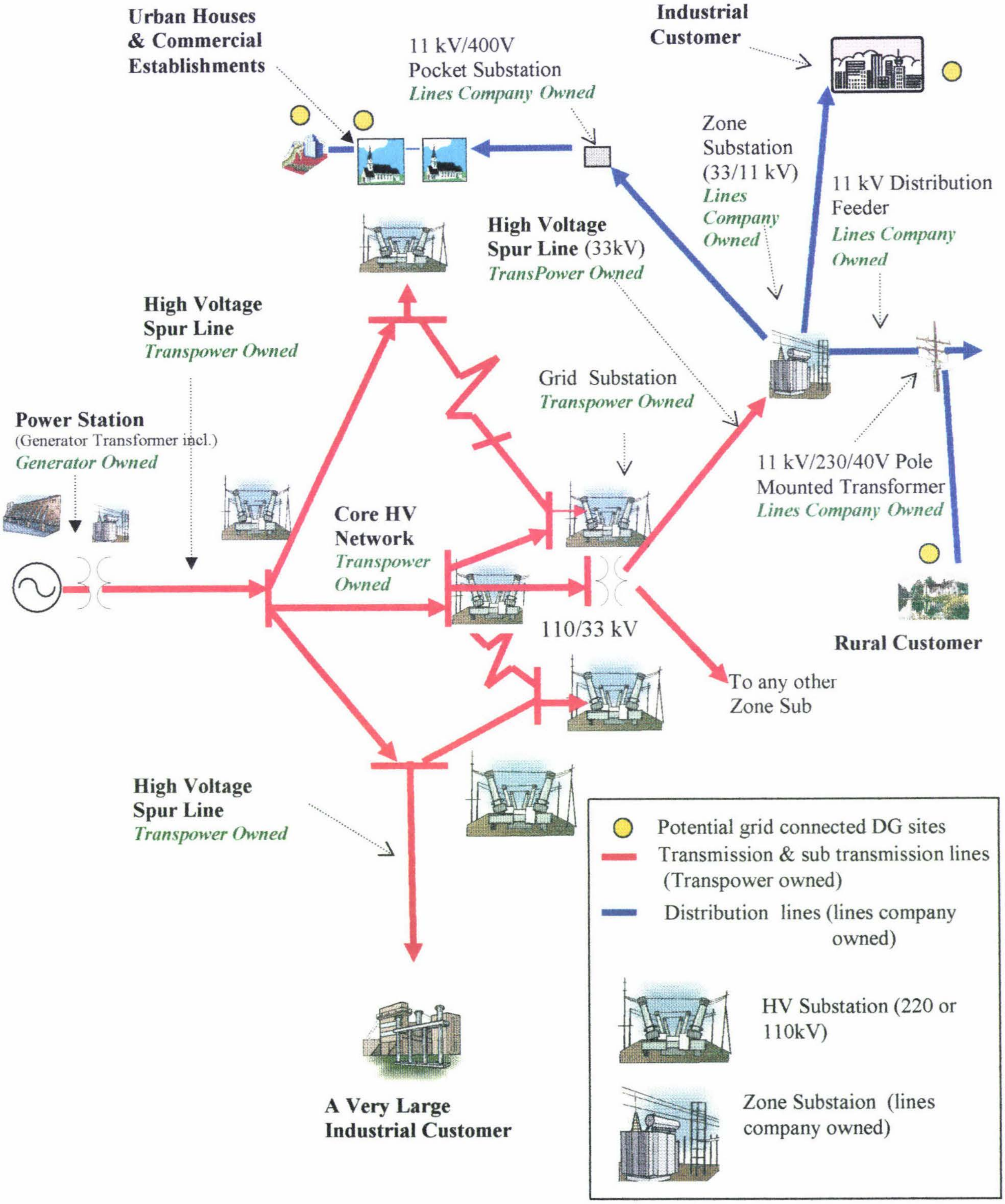

Fig. 2.1: New Zealand's power system framework depicting key fixed assets and its ownership

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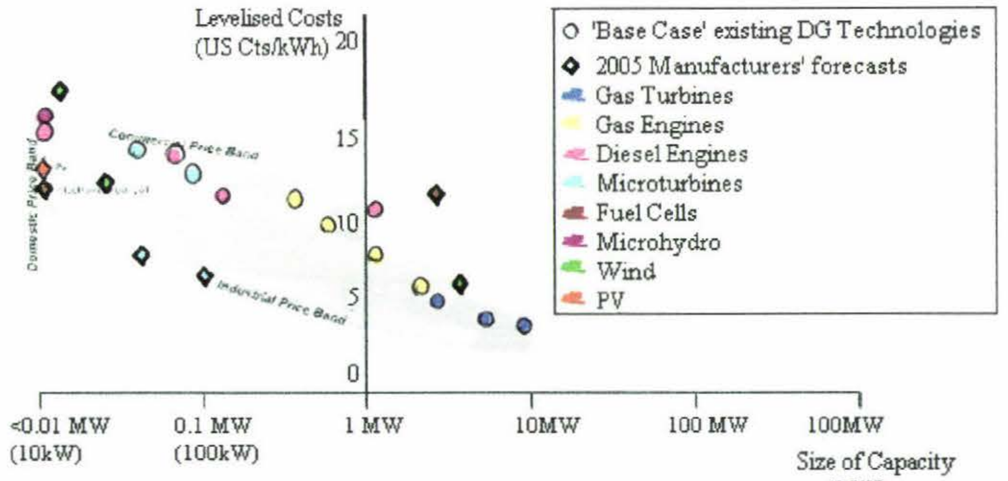
[4] *For the sake of simplicity, the HVDC system between Benmore and Haywards, which is an integral part of Transpower's core HV system, is not shown in Fig 2.1*

The diamond shapes in Fig. 2.2 refer to year 2005 forecasts for different technologies (as identified by their colour code), while circular shapes refer to year 2001-2002 actual figures of these technologies.

Since distributed generation takes place at the customer end of the electricity network, it can be any location down stream of the zone substations of New Zealand's electricity distribution network. As in the case of other countries, in New Zealand, the customer's electricity tariff meter demarcates the interface point between the electrical utility and the customer. The interface point is commonly referred to as the "Installation Control Point (ICP)". When a DG facility is connected to the customer's electrical mains the capacity of the facility is limited by the kW rating of the customer's electricity supply, which is typically 15kW for a residential customer.

2.4 ECONOMICS OF DG

A 1999 US study compared the existing levelised cost of electricity for different DG technologies along with the projected levelised costs by the year 2005 and the corresponding economies of scales resulting from larger DG units (Fig. 2.2). As in the case of New Zealand, the low price band to the US industrial sector for grid-connected electricity (Fig. 2.2) is due to proportionally lower metering and overhead costs to the retailer and network operators' ability to utilise their fixed assets more efficiently, such as using dedicated fixed assets at high load factors for large industrial customers.



Small scale distributed generation will compete with the delivered cost of electricity, not the wholesale cost!!

Fig. 2.2: A USA study on the economies of scale of different modern DG Technologies *(CAE, 2002)*

The study clearly indicates that some small-scale DG technologies would very soon become cost competitive to an average US household. Analysis of the establishment of the price of grid connected electricity to a New Zealand end user would enable formulation of strategies to enhance the value of DG as well as to improve the overall efficiency of the electricity industry.

2.5 PRICE OF GRID CONNECTED ELECTRICITY

With the exception of very large industrial customers who have bilateral contract agreements with the generators for supply of electricity, every other consumer in New Zealand buys electricity from an energy retailer. Principal determinants of the price of electricity to such a customer are:

- the wholesale price of electricity (2.5.1) ;
- the retailer's cost structure and the required rate of return (2.5.2) ; and
- the pricing methodology of the network operators (2.5.3), namely Transpower and the local lines company through whose assets (i.e. the 11kV and 400V network) the electricity is conveyed to the customer from Transpower's grid substation (Fig. 2.1).

2.5.1. The wholesale price of electricity

Electricity is a commodity that cannot be stored economically at the large scale. This means having to match aggregate demand for electricity (which changes every second, every minute, every hour and every day) against the aggregate supply in real time. In physical terms this refers to scheduling and dispatching the necessary generation resources (owned by the generators) to the system, which is a task accomplished by Transpower.[5] In market terms matching supply with demand results in constant positive interaction between buyers (including retailers) and sellers (i.e. generators) in a wholesale market, whose combined actions determine the price of wholesale electricity at any given time.

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[5] *Frequency of the power system (50Hz in New Zealand) acts as the barometer indicating any mismatch of supply and demand. For example when the demand increases relative to the supply, the system frequency drops due to retardation of the turbines due to higher loading. This is sensed by the speed governors of the controllable generation sources. It is necessary for the dispatcher Transpower to ensure that an adequate amount of reserve is made available to the system by issuing proper dispatch instructions to the generators. In addition to stabilising the system at 50Hz frequency within limits, from time to time, the grid operator also issues instructions to generators to adjust (increase or reduce) the voltage at their end to maintain the desired voltage profile in the high voltage network.*

Two types of trading transactions take place in wholesale electricity markets. About 80% of the wholesale volume of electricity is transacted through the New Zealand Electricity Market (NZEM), which is a voluntary self-regulating market[6]. The balance comes under the purview of the Metering & Reconciliation Information Agreement (MARIA) as individual bilateral contracts between large buyers and sellers (MED, 2000). Although retailers also participate as buyers, the bulk of the trading under MARIA[7] confines to large industrial customers (as buyers) directly connected to the national grid and the generators (as sellers).

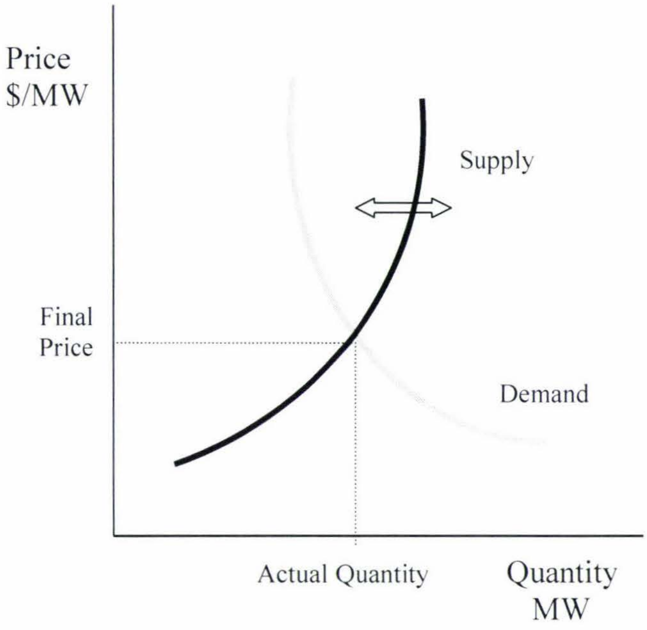

Fig . 2.3: Supply & demand dynamics and how the spot price is discovered in the NZEM. *(M-co, 2002)*

NZEM being a free enterprise system, the spot price of electricity is determined by the aggregate supply and aggregate demand[8]. However the supply and demand changes in real time which makes the spot price very dynamic. For example due to a constraint in the transmission system, the whole generation loading pattern in the national grid may have to be changed quickly as demand changes, meaning adjusting the supply schedule (i.e. the supply curve) relative to the demand, as illustrated in Fig. 2.3.

The NZEM operates within a set of guiding principles developed in consultation with Government and a set of rules developed by the market participants. These rules cover every aspect of trading from entry criteria through to market settlement. The NZEM Rules Committee overseas the general operation of the rules and works to ensure their continuous improvement while the independent Market Surveillance Committee (MSC) monitors compliance. The market participants are primarily the generators[9] that offer electricity into the marketplace and the retailers that buy electricity to supply their customers (M-co 2003).

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[6] *There are a few legislative and Government restrictions however.*

[7] *MARIA's scope on metering performance is not limited to energy flows related to the wholesale market.*

[8] *In economics supply means the whole schedule of prices the producers are willing to supply for different quantities produced under a given condition. Similarly demand means the whole schedule of prices buyers are willing to pay for different quantities (Ahuja 1998).*

[9] H*edging is allowed, subject to a set of NZEM rules, to cover the risks.*

The service providers undertake a variety of services in the market, which is summarised in Table 2.1.

Service Provider	Function
M-co	**Market Administrator**: Provides analytical and administrative support to the MSC and the Rules Committee. Also provides a comprehensive web based market information system (known as COMIT) for the benefit of current participants and potential entrants.
	Pricing Manager: Calculates and publishes NZEM final prices. At present prices are discovered for each half-hour period at 244 different grid connection points (also called nodes) in the national grid.
	Clearing Manager: M-co clearing house settles NZEM, monitors prudential security requirements (to cover any payment defaults by buyers) and producers' invoices for electricity purchased and notifications for electricity sold. It also operates the must run dispatch auction that enables generators to offer electricity into the market at zero price to ensure dispatch.
Transpower	**Grid Operator:** Maintains the security and quality of electricity supply over the national transmission network.
	Scheduler: Provides detailed day-ahead plans of how power stations are expected to generate to meet bids by market participants.
	Dispatcher: Matches real-time demand and generation, then issues dispatch instructions to generators and providers of reserve.
d-cypa (a Transpower subsidiary)	**Reconciliation:** Reconciles metering data against reconciliation contracts. Returns are provided to the Clearing Manager to enable the calculation of the amounts owed to and by participants.
Jade Direct	**Provision of the Registry:** The registry is a database that shows which retailer supplies each ICP so that energy flows between retailers can be reconciled. The registry provider also informs retailers if one of their customers has switched supplier.

Table. 2.1: NZEM Service Providers and their role (M-co, 2003).

"Nodes" referred to in line 1 paragraph 3 of page 18 are also refereed to as grid exit points (GXP) as they demark the interface between the transmission and distribution lines (i.e. ending of the transmission and beginning of the distribution lines).

In practical terms the supply curve is realised on offers made by generators, by way of the least cost offer being dispatched first, followed by the next lowest and so on, until the required quantum of electricity is generated to meet the demand, where the equilibrium is reached. Therefore the price of electricity reflects the final generator's marginal cost (MED, 2000). All generators are paid on the basis of this final equilibrium price irrespective of what they offered, as the final generator's marginal cost defines the price at which the required quantity of electricity could be supplied by the industry, as collection of suppliers.

Grid security is also a factor that determines the final price as actions such as maintaining generation spinning reserve to meet sudden load increases amounts to additional costs. In New Zealand the Multilateral Agreement on Common Quality Standards (MACQS) binds the dispatcher for system security. Grid security committee is appointed as the primary decision making body within the contractual structure of MACQS (Transpower, 2002).

As buyers buy electricity from different locations (nodes) of the grid and generators have to overcome transmission losses and grid constraints to deliver electricity to each location, it is not possible to establish a country wide uniform wholesale spot price (i.e. price at each node to be identical). A key requirement for efficient discovery of price (i.e. at least cost) through supply and demand in an economy is for buyers and sellers to have the required information to make their decisions (Ahuja, 1998). In the NZEM, buyers and sellers are allowed to make bids and offers for each node for each half hour block, 36 hours ahead and then revise the same. However bids and offers are not entertained later than 2 hours before electricity is actually produced and consumed. Transpower calculates (and forwards to M-co) forecast prices for each node taking into consideration these bids and offers, MARIA agreements and projected grid load flow patterns (which also determine grid constraints) and system security requirements (MED, 2000). The bidding and offering gets intensified as the 2-hour cut-off is approached as market participants become more knowledgeable on the possible actual scenarios with regard to the prices.

Due to the dynamic nature of the process, the final price (for each node and half-hour time slot) can sometimes vary considerably from the forecast price that was calculated on the basis of even the most recent information (i.e. the 2 hours before). However the merit of the discovery of nodal price through the market mechanism is the indication of strong investment and location signals to market participants (MED, 2000).

The reader should not confuse "ripple receivers" referred to in line 3 of the final paragraph of page 19 with "ripple transmitting equipment" referred to in line 7 of paragraph 2 of page 23, as they are two different sets of equipment in two different locations.

A ripple transmitter sends a signal (usually along the distribution line) from the substation, which is intercepted at the customer end by the ripple receiver. The ripple receiver manipulates loads such as hot water loads in response to the signal received. In New Zealand, normally the lines company owns the former and the retailer owns the latter (some exceptions exist).

There have been conscious efforts on the part of the government as well as the market itself to effect changes with a view to improve the market efficiency. For example it is proposed that the governance structure of the wholesale market be brought under a single entity. Having separate bodies MARIA, NZEM and MACQS (all of whom share some common service providers) is seen as duplication of resources (MED, 2000). Arrangements were underway to call for a referendum among market participants to merge the three entities to come under the purview of the Electricity Governance Board (EGB) which has been coexisting since 2001. This failed so government is currently in the process of appointing 7 members to an Electricity Commission to overview the industry.

There is also a forum on the merits and demerits of the present method of establishing prices on half-hourly basis vis a vis on a more real time 5 minute interval basis. The rationale for proposing 5 minute pricing is for the spot price to more accurately represent the supply side and demand side dynamics and hence send better signals to the market participants. A typical example of such a dynamic situation is when the winter morning peak starts ramping up at around 6.00 am picking up gradually for the first 20 minutes and then rising exponentially in the next 10 minutes. The existing 30 minute spot price calculation assumes that variations within the time interval to be uniform (hence linear) whereas in reality, for the above-mentioned scenario of load ramping, the pricing should be heavily weighted towards the events of the last 10 minutes (Transpower, 2003). At present 5 minute pricing is published on M-co's website "COMIT free to air" as a trial for the market participants to gain first hand information on it and to promote a healthy forum on its application [10].

2.5.2. The retailer's cost structure and the required rate of return

Retailers are businesses that compete to meet consumers' electricity needs. They provide a full service to their customers by purchasing electricity from NZEM or bilaterally. They also provide some distribution services such as maintaining ripple receivers for electric hot water load control. The customers do benefit if the market it self diciplines the retailers to lower their expected rate of retrun to a level which is commensurate to the business risk they take (and no more). This is caused by creating an environment that promotes

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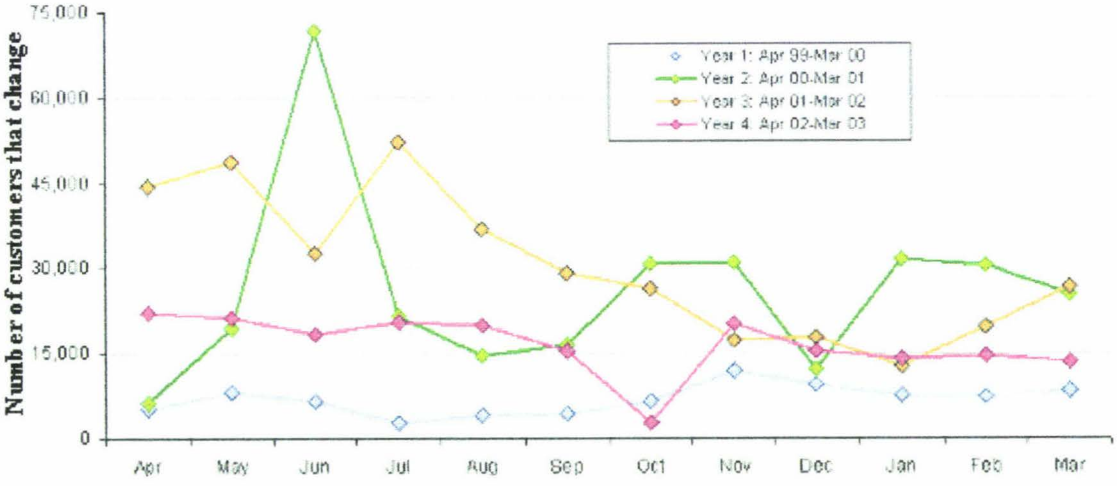
[10] *New Zealand's "COMIT free to air" is credited with the distinction of being the word's first web based electricity wholesale marketing information system.*

Delete the words “**a steady**” from line 3 paragraph 2 of page 20 and substitute the word “**an**”.

Fig. 2.4. shows that customer switch rate has first increased and then stabilised since low cost customer switching was first made possible by MARIA from 01 April 2000. This kind of customer behaviour is typical for any generic new product or service. Since a change is recorded each time a customer changes the retailer, and each change is reckoned as an additional customer in the vertical axis of Fig. 2.4 and one customer can change the retailer several times, Fig. 2.4 is not a 100% accurate tool to depict customer behaviour.

rigorous competion in the retail market[11]. Two indicators that could be used to ascertain competitiveness in the industry are the retailer market share and the customer switch churn rate (MARIA, 2000).

New Zealand's retail market is characterised by a couple of strong competitors, none of which is in a position to dominate the market (M-co, 2000). The customer switch rate of the retailer has also seen a steady increase since low cost customer switching was first made possible by MARIA from 01 April 2000 (Fig. 2.4). The low cost customer-switching regime signals a very important milestone in the annals of New Zealand's electricity deregulation drive as it enabled residential customers the freedom of retailer choice. Previously customer switching was only realisable in respect of customers who were having time of use (TOU) energy meters, which profiled customer energy consumption on a half-hour basis enabling retailers to bill the customers on the basis of going market energy rates. TOU meters that profile load at short intervals (such as half hour) use solid state technology but are too costly at present (NZ $ 250 approx. for supply and installation per domestic single phase meter) and only large consumers can afford them.



This graph is a barometer of customer switching activity, and while not 100% accurate, is likely to reflect the trend. A change is recorded each time a consumer changes supplier, including if a consumer moves house and changes to a retailer other than the retailer already supplying that house.

Fig. 2.4: The progress of retailer switching by customers since April 2000 *(M-co, 2003)*

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[11] *Using the concepts of microeconomics it can be shown that perfect competition causes sellers to receive a rate of return (which is termed as normal returns) that is just adequate to keep them in business (Papas 1987).*

The low cost switching regime implemented by MARIA is called "deemed profiling" because it is based on the presumption that a particular household has a load use characteristic that is typical of a known class of households. The technique clusters households (or to be specific, ICPs) into certain load profile classes of whose time series half hour load data has been obtained using statistical sampling techniques. Based on a load shape, retailers can workout the charge rate (cts/kWh) to be applied to their customers.[12] In doing this they cover the risk (i.e. uncertainties surrounding spot price variations) by loading the charge rate with a premium. To facilitate customer switching, each ICP in the country is given a unique identification number, which is stored in the electronic database maintained by the national registry. Retailers of course have access to the registry.

2.5.3. The pricing methodology of the network operators

2.5.3.1 The general approach and governing rules

A key financial objective of any firm is to price its good or service with a view to obtain a rate of return on its investment, which in the opinion of its shareholders is commensurate with the business risk. The revenue collected after covering its costs should yield the target return on investment. In accounting, investment (equity capital plus debt capital minus the working capital) is equal to total assets. In a utility business, the fixed assets are system assets that form an integral part of the electricity reticulation system or power generation system and non-system assets (e.g. machinery and buildings). For electrical utilities, the bulk of the asset structure will consist of system assets.

By nature network operators are natural monopolies in the sense new entrants are barred from entering the market due to complexities that exist in the electrical power transmission and distribution network. In order to control the exercise of monopoly powers the crown has intervened by passing necessary legal requirements, which the network operators have to comply with.

A key requirement a lines company and Transpower have to comply with is to value its system fixed assets in accordance with the handbook prepared by MED[13]. The handbook

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[12] *In practice however most utilities use one type of MARIA approved load profile; that is the net GXP profile, which is the load profile at the grid exit point minus the sum of all TOU metered load profiles.*

[13] *At the time of writing the valid version of the handbook was the 4th Edition, October 2000. The handbook states that accounting treatment of non-system fixed assets and current assets should be in accordance with generally accepted accounting practice (GAAP) in New Zealand.*

states that the sole purpose of the valuation methodology is to support the disclosure and performance measures of lines companies and Transpower under Regulation 15 of the Electricity (Information Disclosure) Regulations 1999. The valuation methodology is completely detached from the book value of assets and essentially based on the concept "Optimised Deprival Valuation (ODV)".

The aim of applying the ODV methodology is to value the assets at the level at which they can be commercially sustained in the long term, and no more. The resulting value shall thus be the loss to the asset owner if the owner was deprived of the assets and then took action to minimise the loss (MED, 2000).

The ODV of system fixed assets of each segment of a segmented network is the minimum of Optimised Depreciated Replacement Cost (ODRC) and Economic Value (EV) of that segment. The ODRC is the replacement cost of the existing system fixed assets at Modern Equivalent Asset (MEA) value, which has been optimised from an engineering standpoint and depreciated according to age. The term optimised in this instance does not refer to a redesigned network to improve the network performance. It basically refers to removal of redundancies in the network such as lowering larger transformer capacities and removal of spur lines (MED, 2000). In certain sections on the network, because of constraints on tariffs, it may not be possible to make a normal rate of return on segments of network when the segment assets are valued at ODRC. In such cases the handbook allows EV be applied.

The handbook stipulates that it is mandatory to conduct EV analysis in respect of a distribution feeder or its spur line which has (1) an average of 3 or fewer customer connections per kilometre, and (2) an average of less than 20 kVA installed capacity per customer connection. This prescription provides a good platform to identify potentially unprofitable sections of the network.

In order to prevent arbitrary asset replacement cost calculations, the handbook stipulates the upper limits in respect of different assets values and their lifetime (to be used for depreciation) for compliance.

There are two important implications stemming from the ODV procedure. Firstly it enables one to identify which sections of a network is deemed unprofitable from a network owner's perspective (i.e. the sections for which EV is reckoned as ODV). Secondly and perhaps ironically, it provides lines companies an incentive to deliberately hold the maximum demand of all network segments at high kW values (to prevent ODRC going below the 'notionally' optimised network).

In this regard to the second matter a submission has already been tendered by Enermet Limited (Enermet, 2002), a leading consulting company, recommending that the ODV rules should include in the preamble or introduction a simple clause stipulating that in calculating the peak load on any network or sub-network for the purpose of optimisation, the lines companies must assume the use of best industry practice with respect to efficient load control on its network. Enermet argued that a lines company which holds the ownership of ripple transmitting equipment to control loads to keep the maximum demand down, may even gradually wind down its activity. The excuse is that they no longer (with a few exceptions) own the ripple receivers (which are at the customer end) and that they are not being informed about how these assets are being maintained. The majority of the ripple receivers are now being owned by retailers (in few cases being subcontracted to asset management companies) who do not have an incentive to maintain it (Hackett, 2002). The importance of load management is covered in section 2.6.

The implication of the above argument is that DG along with other new demand side management (DSM) technology which invariably reduce the maximum demand, could well be seen as a threat by lines companies, unless there are genuine concerns on the maximum demand capacity which they find difficult to cope with. The current state of knowledge on the impact of DG on lines companies is inconclusive and needs further research.

2.5.3.2 Transpower's pricing methodology

The Transpower's total revenue requirement is calculated on the basis of its capital (total assets) requirements. The capital requirement (related to system fixed assets is the ODRC (as on the date of valuation) multiplied by the Weighted Average Cost of Capital (WACC) after deducting the depreciation cost. Transpower calculates its revenue requirement to realise its capital requirement plus its operating cost, the maintenance cost and the overheads. A key task Transpower undertakes in its pricing is the identification of customer/s for each segment of its network assets (for which ODRC is calculated), for the purpose of correct revenue allocation for cost of capital of system fixed assets, O&M costs and overheads. The cost of capital of non-system fixed assets is embedded in Transpower's overheads charged to the customers. An adjustment charge known as Economic Value (EV) adjustment is levied on customers on account of having to reckon the EV for certain segments of the network (section 2.5.3.1) and having to use estimated parameters such as WACC to determine its revenue requirements (Transpower, 2002). Transpower's pricing methodology obviously conforms to ODV asset valuation rules.

Transpower's system assets are segmented under three broad customer categories, namely the customers to whom the HVDC network could be assigned, customers to whom a spur lines plus the corresponding substations (which connect to the core HVAC) could be assigned and customers to whom core HVAC assets could be assigned.[14]

The HVDC network is assigned entirely to generators in the South Island on account of the fact that they are the party who benefit from the export of power to the North Island. The corresponding charge made by Transpower is called the HVDC Charge. The HVDC charge levied to any given South Island generator is computed by multiplying the HVDC rate ($/kW) by the generator's anytime maximum kW injection (AMI). The rate has been so set to cover Transpower's return on HVDC assets, O&M, overheads and no more.

A spur line (and the associated substations) is assigned to a generator, a lines company or a large industrial customer, depending on the particular spur line and the corresponding substations. The corresponding charge made by Transpower is called the Connection Charge. This consists of four components,

- to realise the required return on connection assets (i.e. spur lines and its substations).
- to cover the operating cost
- to cover the maintenance cost and
- to cover the overheads.

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[14] *As mentioned earlier Transpower's customers are generators, lines companies and very large industrial customers.*

The core HVAC assets, which amount to approximately 60% of Transpower's fixed assets, are assigned entirely to line companies and large industrial customers (i.e. to customers who off-take as opposed to who inject energy). The corresponding charge made by Transpower is called the interconnection charge. Like the HVDC charge, the interconnection charge consists of one component only. The HVAC charge ~~levied to a given South Island generator~~ is computed by multiplying the HVAC rate ($/kW) by anytime maximum kW demand (AMD)[15]. The rate has been so set to cover Transpower's return on core HVAC assets, O&M and overheads (associated with the HVAC assets), and no more.

The EV adjustment charge is allocated to all customers in proportion to their connection, interconnection and HVDC charges. Apart from the connection, interconnection and EV adjustment charges, line companies may also be charged for various services such as voltage support and frequency regulating reserve. These charges are very marginal however.

2.5.3.3 Lines company pricing methodology

The approach adopted by lines companies in calculating the revenue requirement is similar to that adopted by Transpower, except for the fact that in the case of the former, the cost structure also includes charges imposed by Transpower (commonly referred to as the transmission charges).

The manner in which lines companies determine their tariff to cover the cost of capital, O&M cost, the overheads and transmission charges vary from lines company to lines company, chiefly due to customer demographics (the number of residential customers, number of commercial customers, number of urban as opposed to rural customers and so on), loading pattern on the network as well as the shareholders' perception on the value of each customer to the company. The total charged to a customer in general will consist of a fixed supply charge ($/day, based on installed capacity) [16] as well as a variable charge on the basis of energy used. Some lines companies may also load a charge based on the capacity (load) drawn by the network (at the GXP) during certain critical peak periods, where capacity shortages exist (Orion, 2003).

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15. *Based on Transpower's present pricing policy AMD is actually the average of 12 highest maximum demands (in kW) for the pricing year.*

16. *The installed capacity is assumed same for all domestic customers and hence the fixed charge will not change from customer to customer in the same region.*

In setting tariffs, line companies will also have to consider any rule imposed upon them by the government. Currently lines companies are subjected to the "10% rule" which stipulates that lines company pricing should be so adjusted that an average domestic customer of less than 8000 kWh per annum, should always at least have a tariff option of which no more than 10% is made up of fixed charges. The rationale for this is the transparency and incentive for domestic customers to lower their bills by reducing the consumption.

The general approach used by lines companies to signal the urban/rural cost differential is to build a differential in its fixed charges, which when the 10% rule is put into contest would mean that an average urban domestic customer would have a lower fixed charge than 10% as opposed to his or her rural counterpart. As mentioned elsewhere, some lines companies (e.g. ScanPower, Electra etc.) do not differentiate between urban and rural customers in fixing their tariffs.

The money and physical flows of electricity among market participates are shown in Fig. 2.5.

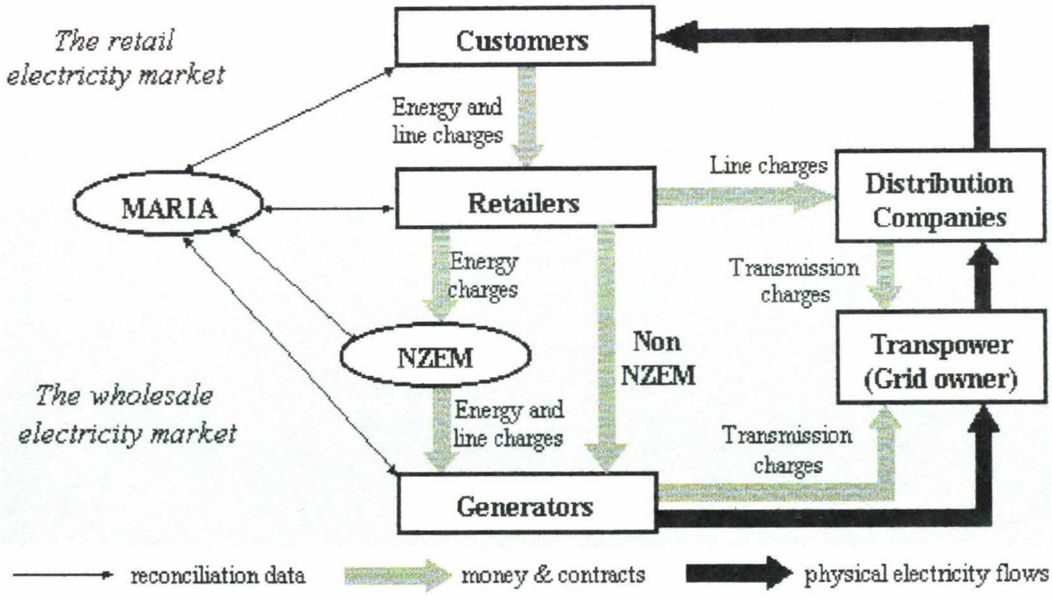

Fig. 2.5: Money flows and physical flows of electricity in the electricity market in New Zealand *(M-co, 2000)*

The traditional approach adopted by a lines company for network management and pricing its product is to maintain and upgrade the network capacity (as the demand grows) by additional investment in system fixed assets and recover the investments through its tariffs.

The answer to whether a lines company would accept a customer into its network after April 2013 may not be very obvious at the end of section 2.5.3.3 (page 27).The answer to this question is complex and depends on the following key factors.

- By law a lines company is not obliged to accept a new customer (even now) if it finds it uneconomical to provide and maintain the supply to that customer (section 1.4).

- A lines company can compensate any lack of revenue from cross subsidies (section 2.5.3.3) and hence customers who are unprofitable on a one to one basis may still be accommodated by having appropriate lines tariffs for different customer classes, as is being done at present by some lines companies.

- More importantly, the terms "economical" and "uneconomical" do not have rigid boundaries as these are contingent on the expected rate of return (profit) of the lines company shareholders. Often a trust owned lines company spells out "community interest" as a corporate objective and consequently a lower return on investment is tolerated. For a private owned lines company a higher return on investment is envisaged as more risks are undertaken by its shareholders (e.g. greater long-term borrowing from commercial banks) and hence commensurate profits. Thus a customer group that is tolerated by a trust owned lines company might not be tolerated if the same group of customers were served by a privately owned lines company.

- As discussed in chapters 8 and 9, distributed generation (DG) on rural networks pose both opportunities (e.g. capacity support for overloaded sections) and threats (e.g. reduction of further revenue). Hence the extent to which DG has an effect on strategic decisions on rural customers (or potential rural customers) varies from lines company to lines company (e.g. some lines companies may not be very comfortable with new technology such as DG), situation to situation (e.g. whether having overloaded sections in the network or not) and extent to which DG expands on rural networks (i.e. DG to become a rule than an exception). The latter depends on technological, regulatory and political factors.

As a strategic alternative to investment in system fixed assets, which is usually a costly investment (as capacity expansion from an engineering viewpoint has to be done in substantial incremental steps, say for example 250 kW blocks), a lines company facing a peak capacity problem can pay a DG owner who can supply just the right amount of capacity at the right time to the network (to release network overload). MainPower and Orion NZ Limited are two line companies who are paying DG owners for such capacity provided as annual payments per average kVA provided during the peak period[17]. The payment rates to the DG service providers are so designed by the two lines companies that when all future payments are discounted to the "present value", it would not exceed the avoided marginal cost of capacity expansion. Under such circumstances payments made to DG owners also forms an integral part of a lines company cost structure (also see Chapter 6 for more details).

2.6. LOAD MANAGEMENT AS A DSM RESPONSE

Load Management is based on the economic concept that a nation's scarce resources should be allocated in the most efficient manner for fulfilling the competing wants and needs of its people. This applies to the electricity industry as well.

Having an unconstrained electricity network means that system generation at all times does increase and decrease to meet rises and falls in customer demand. The generation system must maintain sufficient spinning reserve to be able to meet a rising demand, without contravening frequency and voltage operating constraints (Ganley, 2002).

To meet the above simple demand-supply model, it is necessary to build a generation, transmission and distribution network that can meet the maximum uncontrolled demand. For example from the supply side, as customer demand grows, more generation capacity is required to be built. Without outside constraints, there are at least three reasons why this model is very expensive to maintain and operate. Firstly generation capacity must be capable of meeting an unconstrained maximum demand. Secondly the distribution and transmission network must be capable of supporting high maximum demands. Finally, as the typical daily load profile has relatively few times of high demand, with extended periods of reduced base load, the infrastructure remains unutilised for most of the time (Ganley, 2002).

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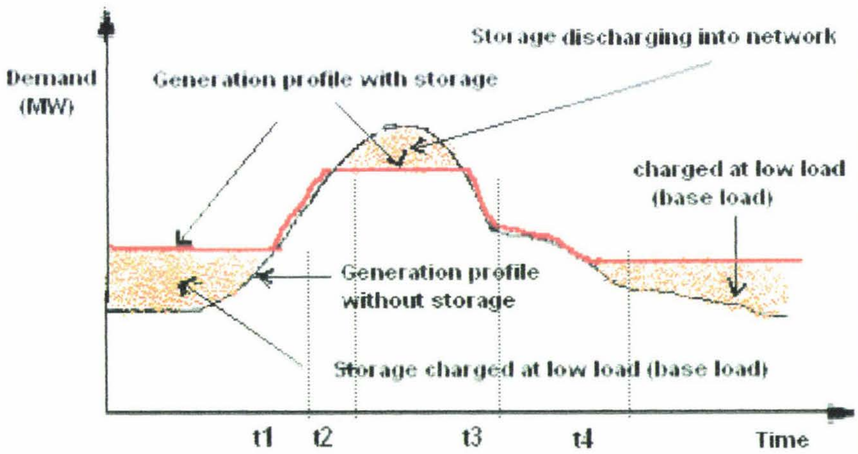
[17] *Orion NZ Ltd., pays small DG owners (who provide capacity during peak periods) on the basis of energy (kWh) provided during the peak period as opposed to (average) capacity provided (kVA).*

There are two traditional approaches that have been adopted universally to counter the above situation; Peak Lopping through energy storage (section 2.6.1) and Peak Shaving by load curtailment (section 2.6.2).

2.6.1 Peak lopping

The traditional method of peak lopping through energy storage has been implemented by building "pumped hydro" storage facilities (fig. 2.6). This is a simple system consisting of two water reservoirs or lakes at different elevations connected by a pump/generator station. During the cheap off-peak time (typically night), water is pumped from the lower lake to the higher one using electric pumps. During peak periods (typically the day), the water flows from the upper lake to the lower one, generating power. The overall efficiency of these systems is usually upwards of 80%. The applicability is obviously tied to geography in that there must be a suitable pair of lakes available (Ganley, 2002). There are no pumped hydro facilities built in New Zealand to date (see section 3.4). One major advantage of pumped hydro is that the reservoir capacities can be designed to hold storage to meet daily demands (say 4 hours) up to seasonal demands of several weeks. Pumped hydro is usually associated with large centralised plants involving large reservoirs. With the advent of new technology there is an increased trend to deal with peak lopping at local level using distributed resources. New technology currently being used, along with their storage



t4 - t1	Storage device starts charging (e.g. starts pumping).
t1	Storage device stopped charging (e.g. pump shutdown).
t2	Storage device starts discharging (e.g. turbine starts generating).
t3	Storage device stops discharging (e.g. turbine stopped).

Fig. 2.6: Illustration of the concept of peak lopping through energy storage *(Price, 2000)*

Although Price (2000) has not listed ice banks as a new storage technology (Table 2.2), certainly some others do include it (see heading "chillers" in page 34). "Hot water" may not qualify as a "new technology" and hence the reason for non-inclusion in Table 2.2.

capacity is shown in Table 2.2. Apart from these technologies fuel cells with hydrogen storage and micro compressed air energy storage (Micro-CAES) systems are also being researched (Price, 2000).

Storage Technology	**Energy Rating**	**Power Rating**
Lead-Acid Battery[18]	1 kWh to 40 MWh	1 kW to 4 MW
Advanced Battery	10 kWh to 100 MWh	25 kW to 10 MW
Flywheel	1 kWh to 5 kWh	5 kW to 750 kW
SMES[19]	400 kJ	750 kW
Capacitors and Super Capacitors	660 kJ	2 MW

Table 2.2: Summary of new storage technologies *(Price, 2000)*

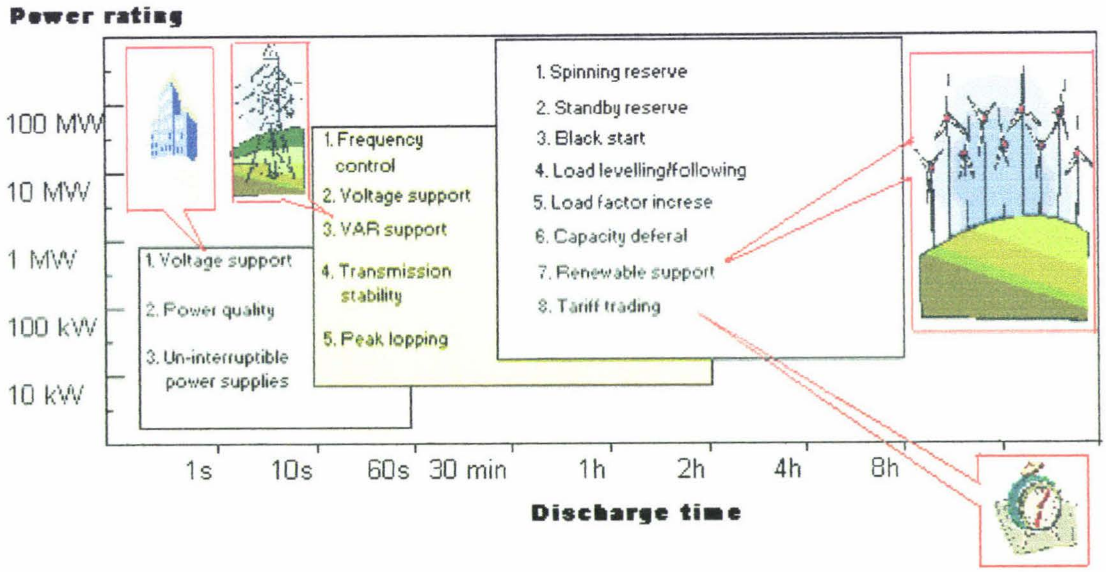


Fig. 2.7: Modern electrical energy storage applications for power systems *(Price, 2000)*

Energy storage solutions for power system applications involving distributed resources can be resolved into three categories, depending on duration of energy required (energy discharge time) for the particular application. The categories as well as the applications are illustrated in Fig. 2.7.

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18. *Although Lead-Acid Battery is not a new invention, it has seen several refinements over the past 2 decades.*

19. *SMES stands for Superconducting Magnetic Energy Storage.*

As evidenced from Fig. 2.7 and Table 2.2, apart from load peaking issues such as high peak and poor load factor, there are numerous other power system issues that could be efficiently dealt with by new storage technology.

2.6.1.1 Modern energy storage technologies for power system applications involving distributed resources

While all applications listed in Fig. 2.7 are important from a power system perspective, some require large energy storage requirements which are realisable only at grid exit points or large customer feeder lines.

Among low to medium energy storage applications involving distributed resources, applications in power quality/voltage support (section 2.6.1.1.1), load factor increase/distribution capacity deferral (section 2.6.1.1.2), tariff trading (section 2.6.1.1.3) and renewable support (section 2.6.1.1.4) have special significance.

2.6.1.1.1 Power quality/voltage support

Power quality is a multi faceted phrase used to describe the extent to which the supply voltage conforms to a perfect steady sinusoidal waveform (DOE, 2002). Today's power quality problems however for the most part are associated with voltage dips, where the electricity supply voltage can momentarily reduce to between 50 and 90% of its nominal value for typically up to a second. Such events have always existed and are mostly caused by the normal operation of protective devices on the electricity transmission and distribution networks during fault conditions (Collinson, 2000). The power quality problems to a contemporary manufacturing firm would mean having to experience shutting down the plant process for no apparent reason, self resetting of process controllers or crashing down of computer systems, all of which result in costly financial consequences. Short term energy storage capability of capacitors has made it an ideal candidate to counter voltage dips, during which period the stored energy is immediately released to maintain the voltage level.

2.6.1.1.2 Load factor increase/distribution capacity deferral

Perhaps the most well documented benefit of storage is its ability to defer or avoid investment in new distribution assets such as cables and transformers, through increase of utilisation of these assets. This is because the net energy (current) flows through network assets during peak times are kept under control through supplying energy through the buffer storage, which is the principal objective of peak lopping.

Load factor (LF) is an index that is being used to gauge the usage of network or power generating assets. It is an important performance parameter of an electricity network operator. LF is the ratio of average load over a designated period to the peak load occurring in that period (e.g. daily LF, monthly LF, winter LF and annual LF). While large utility scale pumped hydro systems would be beneficial to control load flows through the transmission network and increase its LF, for more local problems (i.e. distribution feeders, transformers and zone substations) one needs to look at smaller scale storage applications that increase the LF of local distribution network assets. This is the area where new storage technologies come into play (Price, 2000).

2.6.1.1.3 Tariff trading

Tariff trading is analogous to trading of shares in a capital market. In theory electricity can be bought at spot rates during cheap times, stored and sold to the buyers (e.g. energy retailers) when the electricity prices are high. For tariff trading to become realisable, apart from investment cost of storage, the sellers need to have clear knowledge of when to buy and when to sell. This task is well facilitated in a well developed computerised marketing information system such as that existing in New Zealand.

2.6.1.1.4 Renewable support

Renewable support refers to complimenting intermittent sources of renewable energy by increasing its dispatchability. Although generation from intermittent sources of renewable energy reduces the production of energy from fossil fuel or nuclear sources, it may not be capable of displacing significant generating plant capacity due to its inherently intermittent nature. Stated alternatively non-renewable generating capacity may still be required to meet real time supply shortages due to shortage of renewable energy flux. This reduces the value of energy from renewable sources, other than from bio energy (Collinson, 2000). Renewable support has advantages for both owners of renewable generators and suppliers of energy storage systems. It also has direct benefit in helping governments achieve their Kyoto greenhouse gas reduction emissions targets.

2.6.1.2 Use of standby generators for peak lopping

Usage of dispatchable DG capacities owned by customers is becoming a popular alternative means of peak lopping at distribution level in several countries including New Zealand. In this regard, reciprocating engines operating in Diesel cycle or Otto cycle have become the DG technology of choice. While the utilities benefit from being able to serve the peak loads without having to resort to rotational load shedding (rolling blackouts) or investment in new capacity, customers do benefit from sale of electricity from idling plant and insulating themselves from rolling blackouts and grid outages.

Many customers have standby generators (also known as emergency generators) as part of an uninterruptible power supply system for their business. Today there are standby generator systems that are tailor made for peak lopping. These systems incorporate a prime-power generator (operated on diesel or natural gas) and paralleling equipment that allows the generator to piggyback on the electrical grid (Flexible Energy, 2003).

The operation of the DG units could also be initiated either on a utility's request or customer's own personal choice (hence induced). Induced operation is realisable if the price of electricity is significantly higher during the local peak load time of the day. The traditional price based approach adopted by lines companies is to signal critical peak periods by imposing high line tariffs and discourage excessive consumption, which to a greater or lesser extent has the same effect as peak shaving strategy implemented via. Ripple Control technology (section 2.6.2). Whenever grid power is more expensive than the running cost of the generator, as a rational investor, a DG owner can switch on the generator to offset demand on the grid. This is particularly attractive for standby unit owners as the capital cost of the generator has already been paid for (White, 2002).

In the past paralleling small generator sets to the grid was deemed uneconomical due to expensive interface devices required for synchronisation. The new technology of low cost efficient rectifiers and grid interactive inverters has now enabled paralleling small generator sets at a relatively lesser cost (DOE, 2002).

As a case study the author has documented in Appendix-C his practical experience on how 3x2MW hydro units with dispatchable generation were used to differ network expansion and pacify certain system crisis situations in Sri Lanka.

2.6.2 Peak shaving by load curtailment.

Instead of lopping the peak by releasing energy to the system through storage or standby generation, the peak can also be shaved by removing energy from the system. This is the design philosophy adopted in New Zealand. Each distribution company has a percentage of controllable loads in their supply area. This load is available to be switched off at times of peak usage. Once the time of peak demand has passed, the load is able to be progressively reinstated. This has the net effect of flattening down the maximum peak demand (Fig. 2.8). Flattening the consumer demand profile reduces the maximum required generation, transmission and distribution capacity (Ganley, 2002).

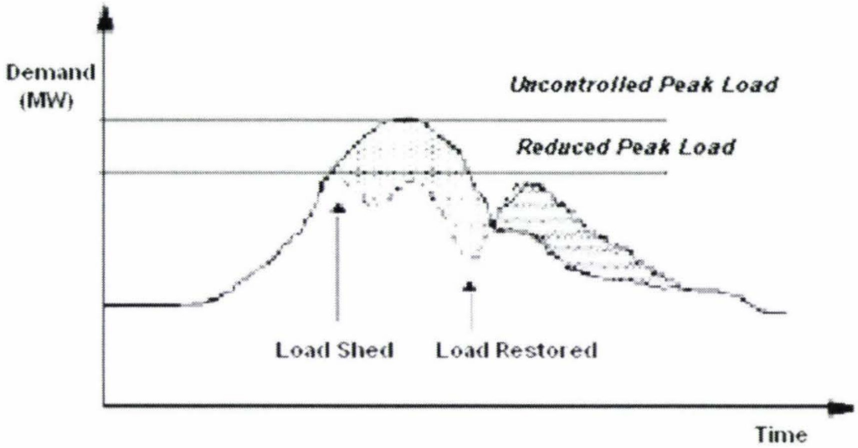

Fig. 2.8: The effect of load shedding on the load duration curve *(Ganley, 2002)*

Downstream of a distribution line, there are a large variety of physical assets and applications that can be switched on or off to control the peak of an electricity network. In addition to these physical assets there are a number of management systems (White, 2002).

Pumps

Many pumps operate to shift water from large reservoirs whenever level drops below or rise above a set level for irrigation. Often this task is not urgent and the pumping could be delayed by a few hours to minimise demand at peak prices.

Compressors

Similar to pumps, air compressors are generally used to re-pressurise a tank when the pressure drops below a certain set point. This task may not be urgent and some time delay may be acceptable to minimise demand at peak prices.

Batch processes

Numerous industrial plants process products in batches (eg wineries, kilns, smelters, quarries etc). Consequently, electricity consumption in the plant can vary significantly depending on the treatment stage the product is going through at a given time. If sufficient notification is given, these processes could be scheduled to minimise consumption at times of expected peak demand. Some difficulty may be encountered if this interferes with scheduling of labour.

Chillers

Air-conditioning and refrigeration applications generally involve cooling a building or storage room to a set temperature at which point the refrigeration system turns off. Significant thermal inertia keeps the room cool for a while until the temperature rises back to an unacceptable level, at which point the refrigeration plant starts back up. This cycling can be controlled to some extent to minimise demand and peak prices. Greater thermal inertia can be put in the system using ice-banks or similar technology. Alternatively, if permissible, set point temperatures can be elevated to minimise load and delay start-up.

Since storage of meat and milk produce is part and parcel of the agricultural livelihood of rural New Zealand, controlling the electrical load of cold storage appears to be a viable option for larger communities, especially if the cooling loads could be consolidated to a compartmentalised single large cold room for which a separate meter and a ripple control receiver could be supplied (section 6.2.2.1). Obviously supplying load control equipment such as ripple receivers for small freezer units or cold rooms is not viable because of the very load and hence energy/line charge being based on GXP loading (similar to a standard customer) which does not take into account the actual load profile at the ICP.

Electric heating

Domestic hot water systems commonly use night storage or ripple control so that non-essential hot water heating does not occur during times of peak power usage (or price). For ripple controlled remote switching, apart from the signal transmitter installed at the substation, each customer (load) should be fitted with a ripple receiver which picks up the signal and operates a relay switch connected to the load. This option is already in place in New Zealand, although the efficacy of the ripple control systems, as mentioned elsewhere, is now being questioned.

Energy efficiency and power factor correction

Energy efficiency from a nation's perspective would mean better utilisation of scarce resources and lowering greenhouse gas emissions. Numerous opportunities are available for reducing energy consumption through technologies such as efficient lighting, variable speed drives, energy efficient buildings and hot water systems etc. These technologies reduce demand and help reduce load in constrained localities. Having installed energy efficient technology, consumers would be expected to use it year round irrespective of whether it was required for a demand side response. Consequently, energy efficiency is not so attractive to power industry retailers who earn less revenue from lower electricity sales.

While power factor correction does not reduce energy consumption at the point of use, it does increase network capacity as it lowers the current flow for a given kW demand. Consequently, power factor correction is particularly attractive to lines companies. However coupling energy efficiency with power factor improvement may become less attractive to lines companies if they end up with a reduced volume of electricity over which it can spread its asset costs.

2.7 THE SIGNIFICANCE OF DG AND BARRIERS TO THE UPTAKE OF DG

Interconnecting a DG unit to the grid can bring many benefits to many stakeholders. From a customer's view point DG could be beneficial for economic reasons as well as improving the quality and reliability of the supply of electricity. From a utility's view point it can be an opportunity in that capacity expansion decisions could be avoided or differed. Utilities can also use DG to improve the quality of service by improving the quality of the electricity supply. At the same time DG could also pose a threat to utilities. These could be related to either technical issues such as affecting the power system protection settings (hence safety) or commercial issues such as loss of revenue for retailers and lines companies. From the state's point of view DG make efficient allocation of resources and help to reduce greenhouse gas emissions. Therefore the state has a direct interest in promoting the use of DG.

The barriers to the uptake of DG should be understood in the above context. Unfortunately DG is not widely embraced in New Zealand as yet. Therefore it is important to learn about the barriers to DG in other counties and strategies they adopt to defeat those barriers.

An "auto recloser" is a switch that operates if the line impendence (as seen by its relay) drops beyond a certain value. The line impedance drops when a line fault such as a short circuit occurs. There is an "upper set limit" on the impedance because the auto recloser would otherwise open for faults (e.g. a branch of a tree touching a line) occurring at a long distance away disturbing the supply to a large number of customers downstream. Because the current as seen by the auto recloser relay drops when DG is also supplying current towards the fault (known as "feeding the fault"), the impedance as seen by the relay (i.e. voltage ÷ current) is increased. Therefore if the fault occurs at the fringe of the operating zone of the auto recloser (Fig. 2.9), because of DG, the relay may mistakenly interpret the impedance as being greater than its "upper set limit" and hence fail to clear the fault for long periods either due to non-opening or delayed opening of the auto recloser.

If the "time to disconnect" the fault is excessive (say above few hundred milliseconds) it may result in grave consequences (depending on the severity of the fault) as currents flowing in the line under (severe) fault conditions are several hundreds and few thousand times higher than the rated capacity of the cables and switches!

The National Renewable Energy Laboratory (NREL) USA has identified three powerful barriers to DG. NERL's observation was based on a sample survey conducted in the year 2000 that reviewed 90 US DG projects with capacities ranging from 300W to 26MW (Nakarado, 2000). Review of New Zealand and Australian literature reveals that NERL's study could be generalised in a global context. The three barriers identified by NREL were; technical requirements for interconnection (section 2.7.1), business practice and contractual requirements (section 2.7.2), economic regulatory issues (section 2.7.3).

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2.7.1 Technical requirements for interconnection

There are four universally accepted operational priorities any electrical utility would pursue. They are safety of the people, safety of the equipment, quality and reliability of supply and dispatch of electricity at a least possible cost (also known as economic dispatch). Among these priorities, safety comes first (Senevirathne, 1985).

One of the most important safety issues for small scale customer sited DG systems is a condition called islanding. Islanding is where a portion of the utility system that contains both loads and a DG generation source is isolated from the remainder of the utility system (e.g. via an auto recloser) but remains energised. Such cases can cause serious safety threats to lines maintenance personnel of a utility company. The other safety threat is the possibility of upsetting the lines company protection system (and hence the lines company assets) in the event of certain line faults (Fig. 2.9) (Van Holde, 2002).

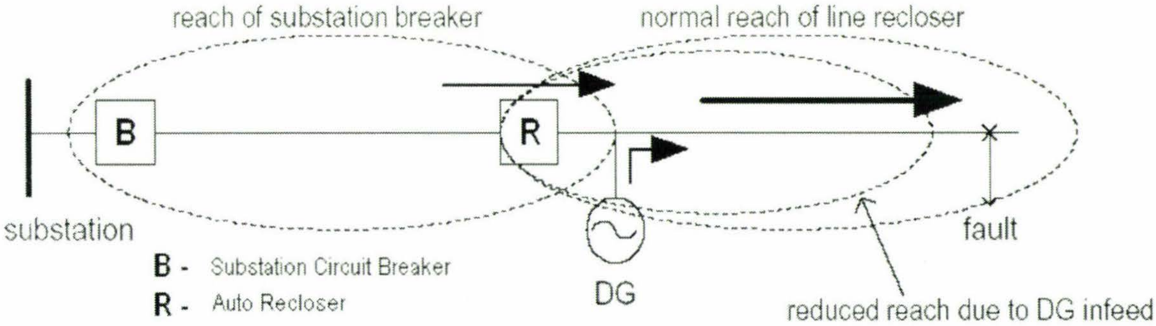

Fig. 2.9 – The effect on the feeder protection scheme upon connecting a large DG unit *(Van Holde, 2002)*

An important observation made by NREL is that interconnection issues that are related to small DG units are very different from interconnection issues related to large DG units. In particular, small scale DG units are usually interconnected to the grid via inverters, which effectively act as the buffer between the DG source and the utility supply, and hence the need to have separate quality standards for small inverters, to circumvent power quality problems such as injection of dc and harmonics to the system.

NREL argue that utilities face a conflict of interest because they have an incentive to discourage self-generation by customers and hence the need to seek uniform adherence to codes and standards developed by nationally recognised independent authorities, such as Institute of Electrical and Electronic Engineers (IEEE), Underwriter's Laboratory (UL) and National Energy Council (NEC) (Nakarado, 2000).

Australia is one of the countries that have a very streamlined standardised approach to dealing with technical issues related to small DG units. The recently released Australian standards AS 4777.1 -2002, AS 4777.2 -2002, AS 4777.3 -2002 have been drafted to address all technical issues in relation to interconnection of small DG units via inverters less than 30 kW capacity. These standards cover installation requirements, inverter requirements and grid protection requirements respectively (Spooner, 2002). Having AS 4777 series means that the only other standard an installer needs to adhere to is the national standards AS/NZS 3000:2000 – SAA related to wiring. The Sustainable Energy Industry Association Australia (SEIA) is working very closely with inverter manufacturers and lines companies to compile a list of inverters which have been tested against AS 4777.2-2002 (or equivalent) and which have been approved for use by electricity utilities. The list is now accessible through the SEIA website http://www.seia.com.au.

2.7.2 Business practice and contractual requirements

NREL observed that some utilities subject customers seeking interconnection of small DG units the same contracting requirements as the developers of large 250 MW cogeneration facilities (Nakarado, 2000). NREL have created an awareness among legislators and regulators that the cost of negotiating and establishing interconnection needs to be commensurate with the size and type of DG facility. Consequently US regulators and legislators have now started recognising the need for simplified, standardised contracts for small facilities.

Other important issues raised by NREL included interconnection agreements containing restrictive terms and conditions (e.g. additional liability insurance requirements, unilateral indemnification requirements and restriction on transfer or sale of DG facility) as well as imposition of fees and charges that reduce or eliminate any incentive for self-generation.

According to the New Zealand Wind Energy Association (NZWEA, 2002), one of the main price disincentives for self-generation is Transpower's pricing policy which places traditional generating companies at a comparative advantage over distributed generators. NZWEA argue that since lines companies levy line charges[20] on all grid inject customers (i.e. DG generators), the same way as they would for an off take customer, and that a significant portion of line charges would consist of interconnection charges levied by Transpower upon the lines companies, the cost of DG generation is inherently higher than traditional generation. As explained in Chapter 2.5.3.2, Transpower does not levy any charge on traditional generators for use of core HVAC assets and hence there are no 'Interconnection charges.' NZWEA propose that Transpower's allocation of costs in connection with core HVAC assets should be shared equitably between both generators as well as lines companies (and direct supply industrial customers) and not the latter alone.

NZWEA also argue that in order to promote the uptake of DG, Transpower's 'Interconnection Charges' be based on energy plus load burden (Anytime Maximum Demand) and not the latter alone as renewable DG is not always able to deliver on demand energy and obtain any benefit of lowering the 'Interconnection Charges' due to the intermittent nature of such resources as wind and solar (NZWEA, 2002).

2.7.3 Tariffs and metering

Economic and regulatory issues pertaining to tariffs and metering refer to different practices the utilities adopt in charging DG owners through various tariffs (through diverse metering schemes), which discourage the uptake of small scale DG.

Appendix-D depicts some common metering schemes for metering utility customers (energy users) engaged in generation of on-site small scale grid connected DG units.

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[20] *Very few New Zealand lines companies however, do not charge for grid injection.*

While there are many options for metering an electrical system consisting of both loads and generators, in a very generic sense, all the options do have a star circuit topology with three legs joined at a common point where at any time the power in any one leg is equal to the sum of the powers in the other two legs. Such a system can be metered by installing meters either on the grid leg only or on the generator and load legs illustrated in Fig. 2.10 below (Roche, 2001).

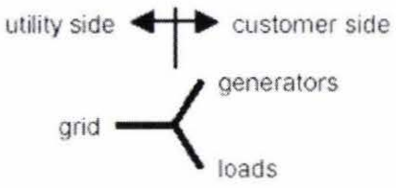

Fig. 2.10: Illustration of the star topology in metering *(Roche, 2001)*.

However different utilities recourse to different metering schemes (and associated tariffs) and not all schemes render similar benefits to the customers (refer to Appendix-D for a detailed analysis).

From a potential DG residential or small commercial customer point of view, the ideal metering/tariff system would be the continuation of the existing metering scheme on a true net metering basis by replacing the existing conventional induction disc type energy meter/s with an identical bidirectional meter/s [21,22].

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[21] *By convention any conventional energy meter is bidirectional. In other words any conventional meter is able to turn backwards for reverse power flow (i.e. generation), unless the disc is detented (i.e. restrained) by fixing a anti-reverse device for security reasons. Like in most other countries, for security reasons all house energy meters in New Zealand are fitted with disc anti-reverse devices.*

[22] *Although it is theoretically possible to use the existing unidirectional conventional energy meters by removing the disc anti-reverse device like some Australian utilities have done in the past with a view to pass benefits to the customers, it is technically unacceptable (hence illegal!) as the meters have never been type tested for reverse power flows (Roche, 2001). For this reason Australian utilities do not now allow the existing meter to be used. Instead two separate unidirectional conventional meters wired in opposite polarity is used (please refer to the metering scheme 2a depicted in Appendix-D). Net metering benefits are still passed to the customers because of the application of the same tariff for both meters (i.e. the import meter and the export meter).*

Countries such as USA use the true net metering scheme and customers enjoy the apparently significant benefit of net metering, which is treating electricity import and export on the same tariff[23]. Moreover having a bi-directional conventional meter will eliminate the customer having to incur a substantial upfront cost on otherwise having to go for a more elaborate metering scheme[24] (schemes 2a through 6b in Appendix-D). Elaborate metering schemes often involve replacing the meter box (on account of having to accommodate more metering equipment) and wiring additional cables between the meters and the customer's main switch at the distribution board.

Also in a true net metering scenario, in terms of the star topology (Fig. 2.10), no meters are connected either to the generator leg or the load leg and are hence considered to be more secure against tampering, which is also a reason often sited for adopting it (Roche, 2001).

It is estimated that upfront cost on meter changing for a more elaborate metering scheme would be of the order of 350 to 400 NZ$, which is a significant portion of the initial cost of a small residential level renewable energy project (e.g. it is 20-25% of the cost of a 200 Wp grid connected photovoltaic module set), which is a main deterrent (Roche, 2001).

The next deterrent for the uptake of small scale DG projects is related to the customer perception on billing and tariff issues. Based on overseas examples, it has been found that regardless of which metering scheme is used, most customers shall be happy with their metering and billing arrangements provided they are given a fair price for the electricity they generate and are provided with a bill that is transparent and easy to understand (Roche, 2001).

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23. *History shows that there is no such thing as true net metering. The truth of the matter is that from a lines company perspective, irrespective of the level of energy use through its network, the company has to charge the customers to obtain the required rate of return for the company to sustain. Hence utilities use various pricing techniques to achieve this objective. For example in USA, it has been found that customers who generate part of their energy requirements (in any given billing interval) are charged at a higher rate for the net metered energy. In the case of customers who generate more than their energy requirements for a given billing interval, the difference is carried forward as a credit (not paid to the customer) for the next billing interval and any outstanding credit due to the customer at the end of the billing year it is written-off (Schedin, 2002).*

24. *The rationale of customers having to bear the upfront cost on having to have a new metering scheme, which is more often the case, is a matter of debate. Some argue that in countries such as Australia and New Zealand, where utilities compete in a competitive wholesale electricity market where price of electricity is established every half hour, it is in the best interest of the utilities to replace existing conventional meters at their own cost by TOU meters in even small DG projects as all customers in any case ought to be billed on a time of use basis at a future point in time . Therefore incurring on TOU meters for DG customers is actually a case of having to bear a possible future cost at present. They also argue wide spread use of renewable energy generators is a social good and hence a social responsibility on the part of a utility to bear the upfront cost on metering (Roche, 2001).*

In many cases, customers have found the tariffs at which they are credited and/or the billing system used by their utility falls short of these ideals (Roche, 2001). Except in the case of the true net metering scheme, in all the other schemes utilities do distinguish between consumption and generation (or import and export) since generation, from the point of view of an energy retailer, who has to buy the electricity produced by the customer, only helps in avoiding costs which would otherwise have to be paid for buying electricity from the wholesale market. Wholesale price of electricity does not contain the value addition involved in having electricity delivered all the way to the customer through the distribution assets (owned by lines companies). Therefore, from a utility company's point of view price paid/credited for electricity generated can be significantly less than price charged for electricity consumed.

2.8 USE OF DISTRIBUTED RESOURCES IN NEW ZEALAND

2.8.1 Distributed Generation in New Zealand

Up until the late 1940s to early 1950s many rural dwellings did not have grid electricity. At the time customers wanting electricity used local hydro, if it was available, or diesel generator set. Therefore DG is not a unfamiliar resource technology to New Zealand (Hooper, 2002). However with cheaper grid electricity becoming accessible all round the country, there was no incentive for anybody to maintain or undertake new DG projects in a larger scale.

New Zealanders enjoy one of the lowest electricity prices among people in the developed world (Fig. 2.11). This coupled with narrow domestic (low) tariff bands for New Zealand households means that DG is not competitive on pure economic terms, which partly explains why DG is not yet widely adopted on a wider domestic scale in spite of new technological innovations.

The limited natural gas reticulation system in the country, which is only confined to the main centres in the North Island, is considered a reason that hinders the uptake of DG at domestic scale (Hooper, 2002). However New Zealand has an abundance of renewable energy sources, most notably wind, solar, geothermal and biomass, of which very little use has been made so far.

Colour bars in Fig. 2.11 (page 42) stands for the following:

Red: Europe
White: New Zealand
Blue: Rest of the world

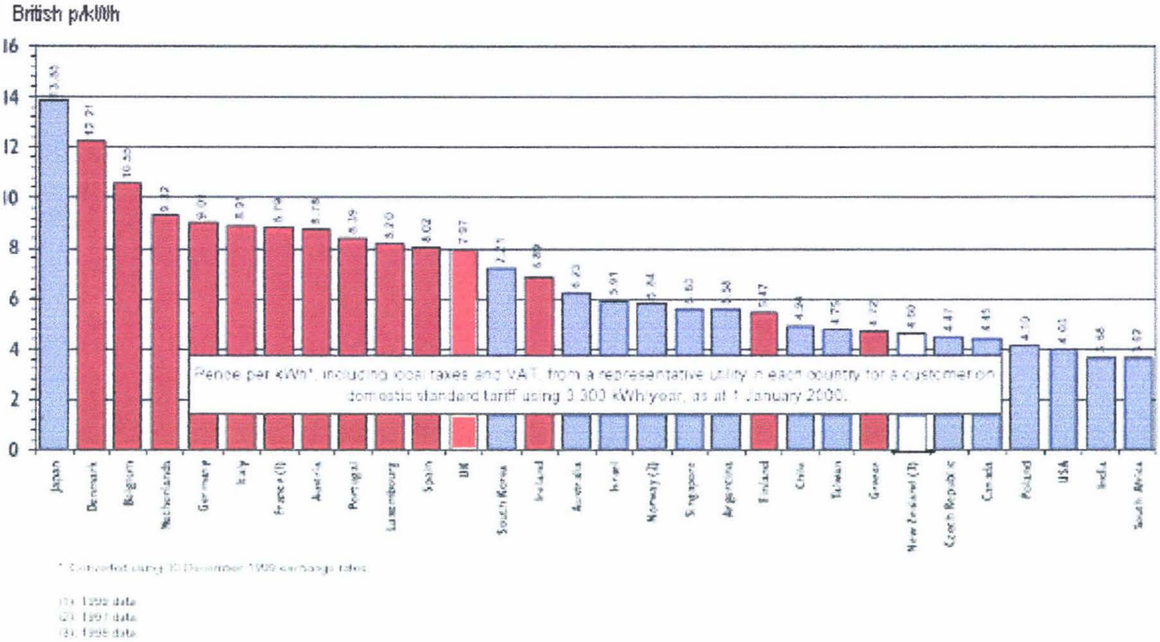

Fig. 2.11: World Domestic Electricity Prices *(Electricity Association UK, 2001)*

On the other hand over reliance on hydro power has seen critical energy storages such as in winter 1992, 2001 and 2003. Building more large-scale generation to offset energy shortfalls (which occur during winter peaks) have at times faced opposition due to environmental concerns and the reduction of natural gas resources. Apart from generation shortfalls, grid security in the country was questioned after the widely publicised calamity to the Auckland Central Business District (CBD) in 1998 on account of a HV cable fault (Hooper, 2002).

Interest levels on DG especially using renewable energy have arisen in recent times, due to GHG concerns, emerging new technologies, the structural reforms in the industry, uncertainties and risks surrounding large generation plants, the grid security issues and the energy crisis (Hooper 2002). A positive stem in this regard was the formation of a study in 2002 by the Centre for Advanced Engineering (CAE) attached to the University of Canterbury, Christchurch, with the objective of investigating the likely implications for the operation and configuration of New Zealand electricity system arising from a possible wide-scale introduction of DG. The study looks at all the relevant market influences, international technology trends and externalities and how various factors may influence the uptake of DG and, as well, the probable likely future impacts on the adequacy of the overall system to meet future demands (Hooper, 2002).

While wide-scale DG is non-existent in New Zealand, as mentioned in 2.5.3.3, a few line companies (e.g. Orion NZ Ltd., MainPower, Eastland) make use of standby generators for system security and peak lopping. For example in Orion's network in the Canterbury region, there are 2x800 kVA diesel generators for system security/peak lopping and a collection of approximately 40 sites owned by private parties. This collectively amounts to 25 MVA (approximately 3% of Orion's maximum demand). Peak lopping is controlled by a signal broadcast over the network by ripple control when Orion has reached a level of 60% controllable load shed. Management of Orion's peak has so far enabled deferment of network capacity reinforcement, which is far more expensive than payments made to the generators for grid support which in 2002 stood at $ 81.92/kVA/yr. Orion documents that as a result of peak lopping initiatives its load factor has improved from 50% to 60% over the last ten years and that investment in a fifth circuit from Twizel substation costing $80 million has been deferred (Hooper, 2002).

The industrial sector on its own initiative has been providing useful DG support chiefly in the form of cogeneration[25] (e.g. Kiwi Dairies 4x10 MW plants) and standby diesel generation (e.g. Port Company's 2x800 kVA sets).

2.8.2 Application of other distributed energy systems in New Zealand

Apart from wood burning stoves, solar hot water (SWH) systems are the most widely used distributed energy systems in New Zealand and currently provide more than 40GWh of equivalent electricity consumption per year. It is believed that by 2010 this figure could be upwards of 600 GWh per year (SIA 2003). Apart from green benefits, SHW technology has direct benefit on load control as 50 to 75% of water heating energy for domestic requirements could be supplied by a well fitted SHW system. Nearly 50% of the total electrical consumption of an average New Zealand household is on hot water consumption.

Energy efficiency, in particular energy efficient building and equipment design, industrial processes and controls that could be used for peak reduction is an area New Zealand is pursuing of late. The country has promoted energy efficiency for over ten years through the Crown entity Energy Efficiency and Conservation Authority (EECA), which also has had a large involvement in determining the National Energy Efficiency and Conservation Strategy (NEECS) released in September 2001 (Hooper, 2002).

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[25] *Collectively, cogeneration capacity in New Zealand amounts to 300 MW, which is about 5% of the total generation capacity of the country. However large cogeneration plants such as the 65MW Te Rapa plant can not be reckoned as DG.*

2.9 SOME RELATED NEW ZEALAND RESEARCH

Irving (2000) in his thesis "Community Owned and Operated Renewable Energy Schemes in Rural New Zealand" observed that there is a strong willingness on the part of rural communities to undertake renewable energy projects where costs and resource consents permit. Electricity supply through a community owned stand alone power supply involving renewable sources would on average be 4.5 times more costly than being supplied with electricity from existing grid connections, chiefly because of having to use battery storage to buffer the intermittent energy supply of renewable sources. In 60% of the cases surveyed, community owned stand alone renewable power systems were less costly than smaller individually owned stand alone renewable power systems. Of the 40% balance the individually owned systems have become less costly because either the owners have had hydro resources readily available to them or they were situated a long distance away from the rest of the community (hence having to bear the distribution cost in the event of a community owned scheme). The optimum legal ownership structure was found to be contingent on the size of the community. In general however, the researcher recommends that "incorporated society" type of an ownership structure would suit most communities.

Redman (2002) researched DG applications at a residential level with a view to develop decision support software to evaluate opportunities in the residential market. The software which operated within the Microsoft Excel framework was capable of outputting the economics of operating fossil fuelled DG units operating on electrical only mode or CHP mode on different operational modes such as base load, load following mode (controlled generation) as well as the economics of DG units that operated from renewables (uncontrolled). The economics of a selected DG mix (i.e. one or more units of same or different technologies) operating in a selected mode outputted four economic parameters; the NPV (net preset value), payback period, ROI (return on investment) and IRR (internal rate of return). The economic parameter calculation was based on the expected net cash inflows in each year during the life cycle of the DG unit/s. A major assumption made in the model was the assumption of a constant avoided cost of electricity, irrespective of the time of operation of the DG unit. Other useful components of the software module included load profile development for either different types of individual households or a network of households.

The crown research entity Industrial Research Limited (IRL) is researching on ways and means of finding how distributed resources including DG could be used for value addition such as improving the network capacity and power quality. With regard to IRL's research on rural New Zealand electricity supplies (Brough, 2002) several important observations can be made.

Firstly rural feeders, which are invariably radially connected from the substation, are characterised by sporadic load growth and it is typical to come across 11 kV distribution feeders spanning in excess of 20km. Unlike in the case of higher voltages, at 11 kV, the AC resistance of the distribution line is a very significant component of the total impedance of the line. Therefore even though rural feeders are lightly loaded, it does not leave room to connect significant switching loads due to voltage flicker[26,27] (Brough, 2002).

Secondly, according to IRL, the voltage regulating systems currently existing in New Zealand, in connection with weak[28] distribution networks are too slow to respond being traditional voltage regulating equipment and voltage support through modern distributed resources are deemed more viable solutions to voltage flicker problems (Brough, 2002).

Thirdly and most importantly, stemming from the first issue, connecting renewable DG such as wind turbines to weak networks can cause serious voltage flickers [29,30] (due to wind turbine power output fluctuations on account of wind speed fluctuations) and could

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[26] *Any electrical conductor transmitting power is limited by two constraints. Firstly, it is constrained by the current carrying capacity of the conductor, which is a function of the cross sectional area of the conductor. A lightly loaded transmission/distribution line will not be subjected to this constraint. Secondly a conductor can be constrained on the maximum allowable voltage drop (typically 10%) which is a function of the impedance of the conductor. For example a switching load such as an induction motor, which typically draws about 5 to 6 times its rated current at the time of starting up (to be precise up until the motor attains speed and develops a sufficient back emf) can cause unacceptable voltage dips across the network, if the motor switching current and network impedance are high.*

[27] *As mentioned earlier, voltage fickler is becoming an increasingly important problem to be tackled effectively, due to widespread use of computer systems.*

[28] *The phrase 'weak line' is used in electrical engineering to characterise a line with high impedance.*

[29] *In the case of wind turbines, effects of voltage fluctuations are exaggerated because their fluctuation characteristics include the most sensitive voltage flicker frequencies (Craig, 1996), as cited by (Brough, 2002).*

[30] *A classic example is the voltage flickers occurring in the distribution network of the state of Tami Nadu, India, due to integration of large number of wind turbines (installed capacity of 900MW approx.) into the distribution network (Sørensen et al 1997). In many ways this is similar to a hypothetical situation of integrating a significant number of wind turbines to rural New Zealand networks without supplementary fast response voltage support equipment being installed.*

limit integration of potentially good renewable sources such as wind. However additional investment in modern distributed resources such as fast response voltage compensation devices can overcome this problem (Brough, 2002). The important implication stemming from this is that any DG configuration, especially as applied to rural New Zealand networks involving renewable sources such as wind, should be technically acceptable in that additional hardware may have be included to minimise voltage flicker.

To date, there is no universally accepted yardstick to measure voltage f$\overset{l}{\wedge}$ickler. This might also be a contentious issue in the future (in the absence of consensus about power quality standards) among entrepreneurs wanting to develop renewable DG sources in rural areas in New Zealand and utility companies.

While there are plenty of opportunities for the integration of distributed resources in the future, further development is necessary to ensure that the power quality is not jeopardised by widespread use of renewable distributed resources such as wind turbine generators on weak distribution networks.

Chapter 3

Technological and Economic Aspects of Distributed Energy Systems

This chapter describes the technological and economic aspects and the future scope of PV modules, wind turbines, small hydro and pumped hydro units and fuelled generator sets and storage batteries. These are central to the distributed generation modeling covered in Chapter 6. A brief coverage on fuel cells and solar hot water systems is also included.

3.1 PHOTOVOLTAIC (PV) MODULES

3.1.1 PV Performance

The building block of a PV module is the solar cell. Solar cells are assembled in a series circuit to constitute a PV module. Solar cell manufacturers may either assemble the cells in a different solar panel production line or sell them to module manufacturers. Most solar cells are manufactured from either crystalline silicon (Si) wafers or wafers made through advanced thin film technologies. In the crystalline silicon wafer versions the Si wafers are cut from either a large single crystal ingot (single-Si) or through a casting process involving molten silicon. As the latter process results in a polycrystalline structure, the wafers cut from it are called polycrystalline silicon (poly-Si). Single-Si process is a more refined manufacturing process and hence more costly. However the cost is compensated by the fact that single-Si cells are more efficient in terms of energy conversion (14-18%), as compared to poly-Si cells (10-14%).

Upon ionising the atoms in the silicon, the internal field produced by the junction separates some of the positive charges ("holes") from the negative charges (electrons) within the photovoltaic device. The holes are swept into the positive or p-layer and the electrons are swept into the negative or n-layer. Although these opposite charges are attracted to each other, most of them can only recombine by passing through an external circuit outside the material because of the internal potential energy barrier.

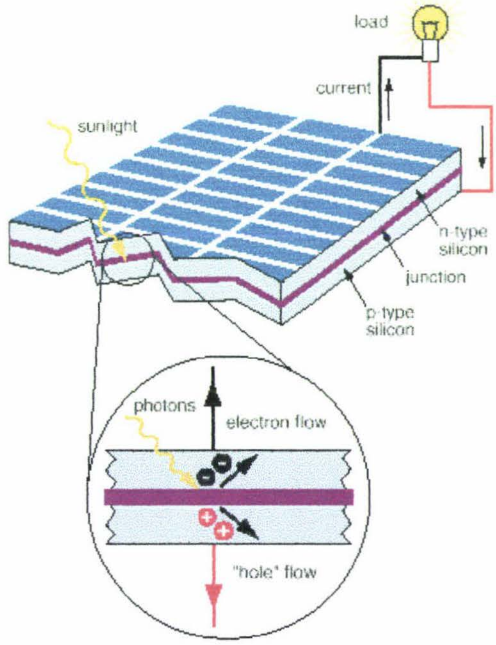


Fig. 3.1: The photovoltaic effect in a solar cell *(ACRE, 2002)*

Accordingly if a circuit is made (as shown in Fig. 3.1) power can be produced from the cells under illumination since the free electrons have to pass through the load to recombine with the positive holes (ACRE 2002). The amount of electrical power available from a solar cell is thus determined by the type and area of the material (Si wafer), the intensity of sunlight (solar radiation) and the solar spectrum (i.e. the wavelengths of sunlight). Apart from these variables, like any other semiconductor device, a solar cell's performance is retarded by temperature (i.e. a negative temperature coefficient of power output).

The standard test conditions (STC) as applied to PV module testing, refer to a solar irradiance level of 1000W/m^2 (which is approximately the maximum sunlight one would expect to receive in summer) at a spectrum AM 1.5 at a cell temperature of 25^{0}C. A typical single-Si solar cell of 100 cm^2 at STC will produce approximately 1.5W of power under optimum conditions, suggesting an efficiency of 15%. Of particular importance to renewable energy design engineers are the operating characteristics of a given PV module.

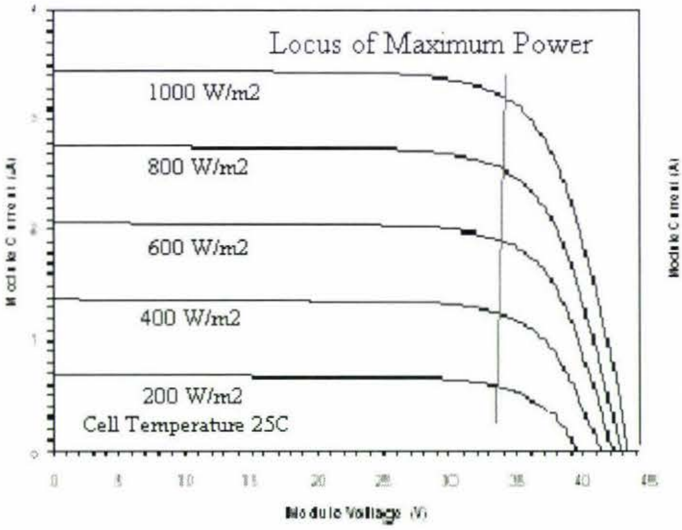


Fig. 3.2 I-V characteristics of Shell SM110-24P PV Module for varying irradiance levels

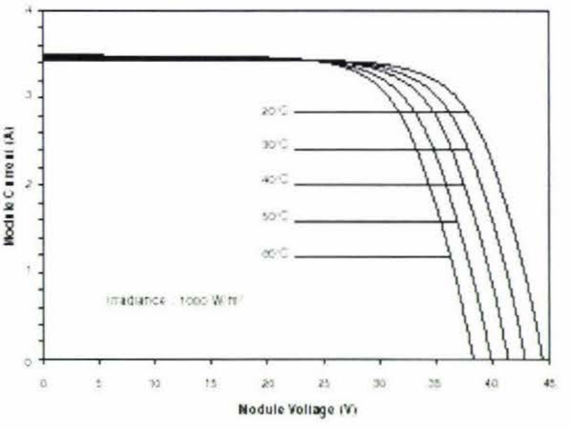
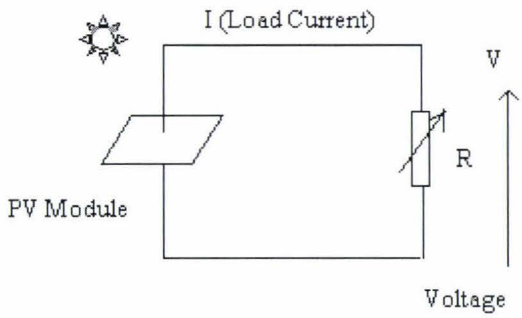


Fig. 3.3 I-V characteristics of Shell SM110-24P PV Module for varying cell temperatures at 1000 W/m^2 irradiance level

Fig. 3.2 depicts how the load current varies with the voltage in a typical PV module under different solar irradiances at 25^{0}C while Fig 3.3 depicts how the characteristics vary under different solar cell temperatures. The experimental set up for voltage and current measurements for determining above I-V characteristics is illustrated in Fig 3.4. The vertical axis values in Fig. 3.2 and 3.3 correspond to short circuit conditions (i.e. $R = 0$ in

Fig. 3.4) while the horizontal axis values refer to open circuit conditions (i.e. $R = \infty$). It has been found that short circuit current of a solar cell or a PV module is very nearly linearly proportional to irradiance. This principal has been applied in the production of one category of commercial pyranometers. The underlying assumption is that solar spectrum remains essentially unaltered.



Another important characteristic of a PV module, as depicted in Fig. 3.2 is that at any given solar irradiance there exists a unique load resistance (i.e. unique V and I value) such that the power dissipated in the load (i.e. the V*I product) becomes maximum. Peak Watts of a module (abbreviated W_p) refers to this value at STC.

Fig. 3.4: The experimental set up for determining I-V characteristics of a PV module

As the maximum power delivery occurs at approximately the same voltage (Fig. 3.2) it follows that in order to deliver the maximum power, the load impedance has to be increased as sunlight drops and visa versa. As summarised by Duffie and Beckman (1991) in practice the matching of solar cell characteristics with load characteristics is accomplished in real time by an interface device known as the maximum power point tracker (MPPT), which acts as a DC to DC converter that sets the load impedance as referred to the PV module side such that it remains at maximum power point V,I values at all times (i.e. under varying solar irradiance). The concept is illustrated in Fig. 3.5.

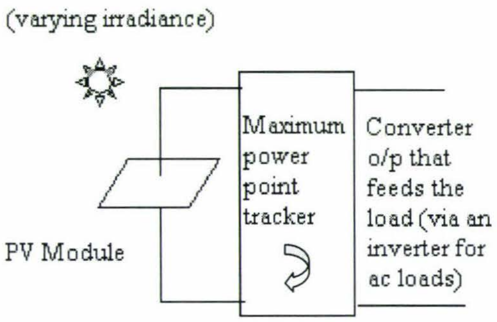


Fig. 3.5: The concept of Maximum Power Point Tracking

The electronic circuit a MPPT sets the input impedance at a value (nearly) equal to maximum power V and I value of the solar cell for any given solar irradiance. Duffie and Beckman (1991) observed that maximum power point tracking devices often achieve high efficiencies of the order of 90%.

Duffie and Beckman (1991) have specified a mathematical model to compute power output of a PV module following a maximum power point tracking operating point, for any ambient temperature and solar irradiation level, given the maximum power point performance (efficiency or power output) of the module for any reference condition such as STC. The underlying assumption made is that DG configurations involving PV modules shall always incorporate a MPPT.

3.1.2 Economics of PV Technology

Although renewable energy generation through PV modules does not involve any significant future cost (in terms of operation and maintenance), the initial cost of a module is still beyond pure economic justification for most DG applications in spite of growing demand.

The average module price as it now stands around US$ 4-6 per/W_p which is a significant improvement compared to the scenario 30 years ago when the price stood at a staggering US$ 100/W_p. Historical cost trends for Si PV modules exhibit an experience curve industry-wide of about 75 to 80%. The experience (or learning) curve shows the module cost behaviour for increasing module production and it is a measure of the economies of scale as well as the technological progress (Menna, 1996). The relationship is defined by the exponential equation $Y = aX^b$ ($a>0$ and $b<0$). Alternatively;

$$\ln Y = \ln a + b \ln X \qquad \text{Eq. 3.1}$$

Y refers to the unit production cost for accumulated production level X. The index 'b' of the above equation is defined as the learning parameter where 'a' is the unit cost at first production. The term *progress ratio* (usually expressed as a percentage) refers to the ratio between the unit cost now with the unit cost when the production is doubled. Specifically progress ratio is defined as;

R_{progress} = (Unit cost when the present production level[1] doubles)/Present unit cost. Eq. 3.2

For the last 20 years, learning curves exhibiting progress ratio of 75-80% have been reported for Si solar cells technology, which means for each doubling in production, costs

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[1] *The production level referred to in Eq. 3.2 is the industry aggregate production level.*

have decreased by 20 to 25% (Menna, 2002). The practical implication of this observed behaviour is that as more and more PV applications are produced in the future, the module prices should come down to a level so that PV generated electricity would become competitive with utility tariffs and hence more applicability in grid connected configurations[2]. As at present, out of the total global PV market only 10% commands for grid connected applications while the balance being used for stand-alone power systems, telecommunications, vaccine refrigeration, security lighting and water pumping (Menna, 2002).

An important economic concept in PV technology is that it is a modular technology in that however big the application is, the generation source would still be built up using commercially available standard PV modules (typically 50Wp to 100Wp). The PV array necessary for a given application is assembled by connecting the necessary number of modules in series and parallel, to obtain the necessary dc busbar voltage (e.g. dc side voltage of the inverter in grid connected applications) and the power rating. Therefore there is little realisation of economies of scale by resorting to large-scale PV applications (Barlow, et al 1997). The unit cost of PV generated electricity would not therefore change much, depending on the size of application other than for possible discount for bulk purchase.

3.2 WIND TURBINE GENERATORS (WTG)

3.2.1 WTG Performance

The kinetic energy in the wind is a promising source of renewable energy with significant potential in many parts of the world. The power contained in the wind (P), which is the rate of change of kinetic energy, is given by;

$P = ½*(\text{wind mass flow rate})*(\text{wind velocity})^2$.

Since wind mass flow rate is proportional to the wind velocity, it follows that power contained in the wind is proportional to the cube of wind velocity. The output of a wind

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2. *However the PV module price over the past 4-5 years has been static, which is probably more a market driven phenomenon than production driven. This is marketers perception that profits can be maximised by increasing mark ups (i.e. by increasing profitability ratios) as opposed to stimulating a greater sales volume by offering a lower unit price (i.e. by decreasing the profit margin ratios). In economic terms, it is the marketer's perception that the price elasticity of demand of PV modules is less than unity (that is if the price of the commodity is increased by one percent, the demand will not be lowered to a level equal or below one percent).*

turbine is therefore highly dependent on the local average wind speed, which suggests that wind projects are generally more financially viable in "windy" areas. Regions that normally present the most attractive potential are located near coasts, inland areas with open terrain or on the edge of bodies of water. Some mountainous areas also have good potential but are often a long distance away from the load to be connected.

In spite of these geographic limitations for wind energy project siting, there is ample terrain in most areas of the world to provide a significant portion of the local electricity needs with wind energy projects (Gipe, 1999).

Wind turbines can be classified in several ways. One is on the basis of the axis of rotation, being either vertical or horizontal (Figs.3.6 and 3.7).

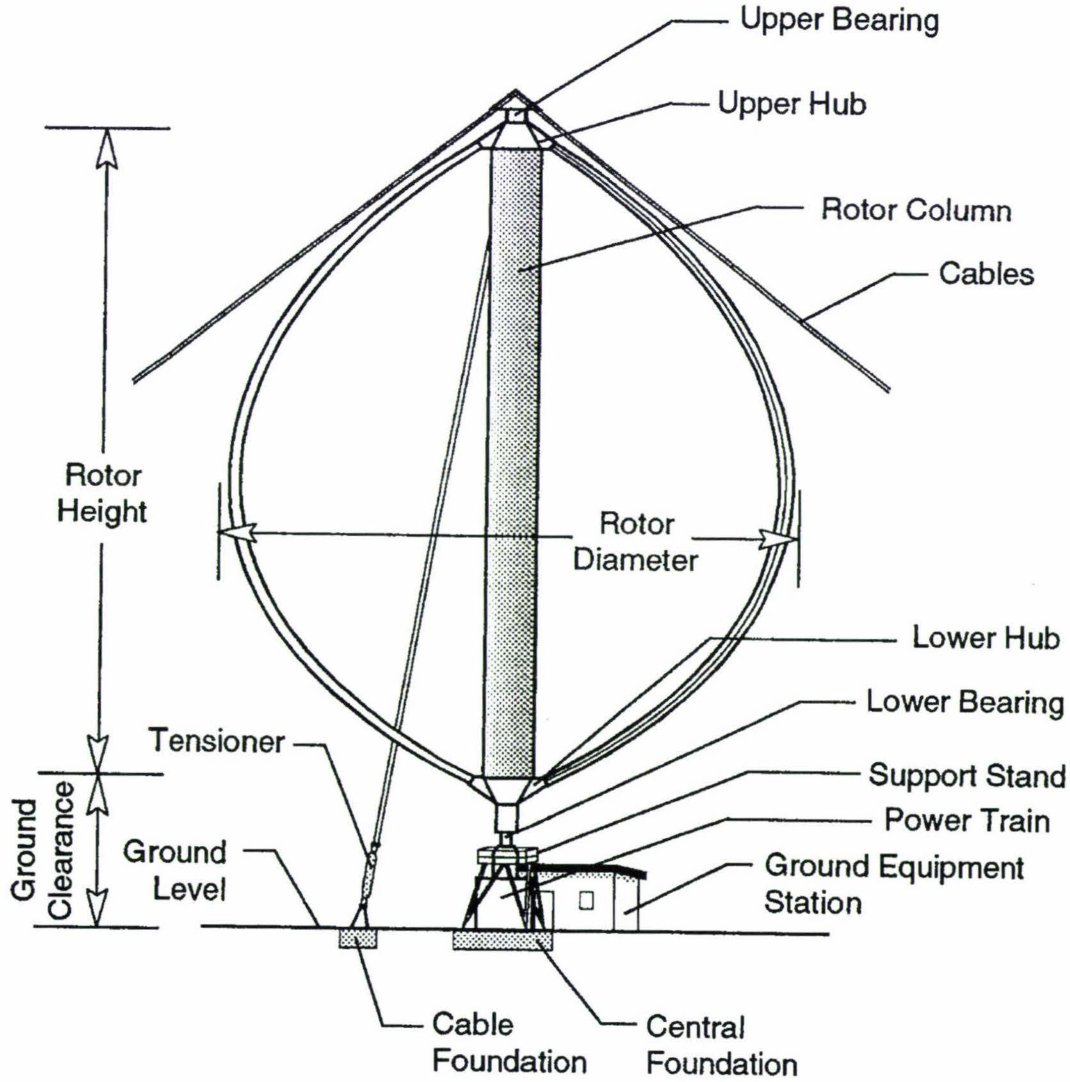


Fig. 3.6: General Configuration of a Vertical-Axis Wind Turbine (VAWT) *(Spera, 1997)*

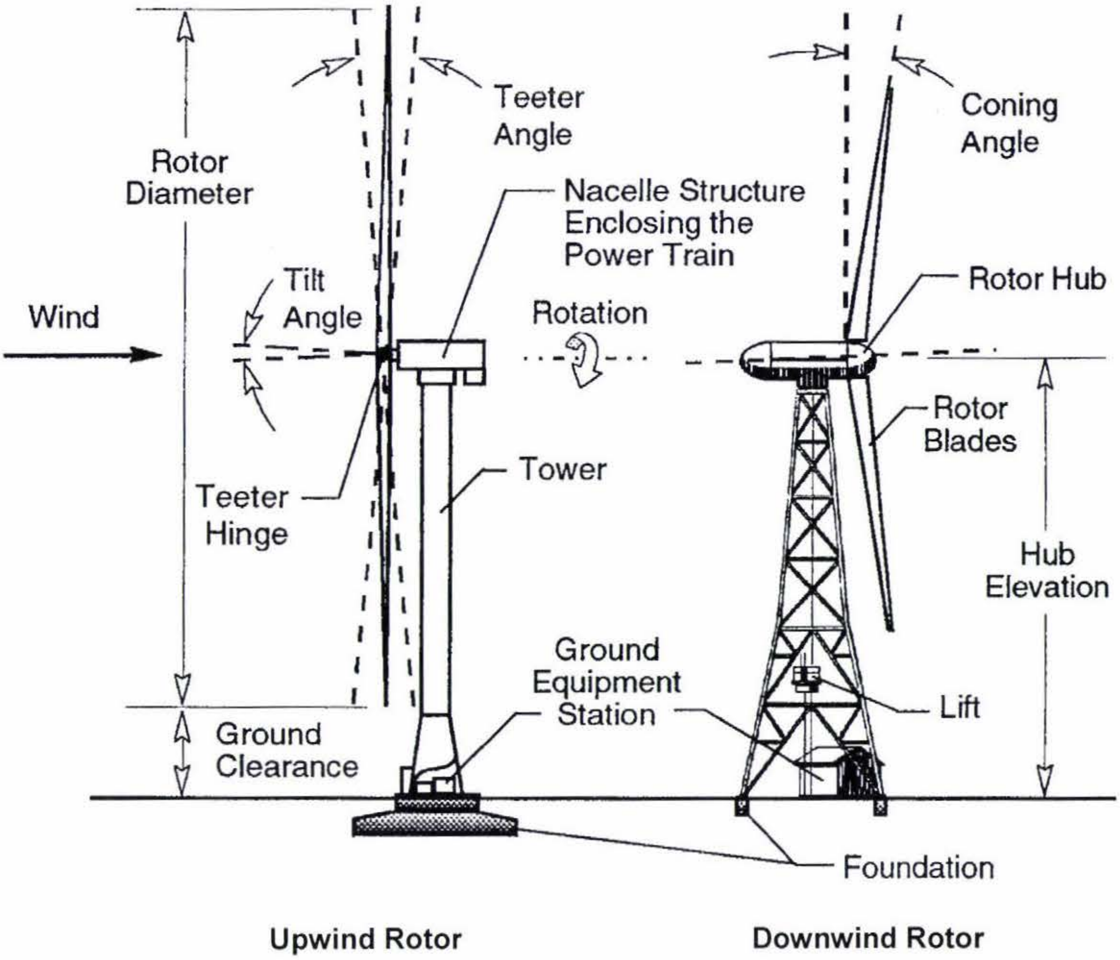
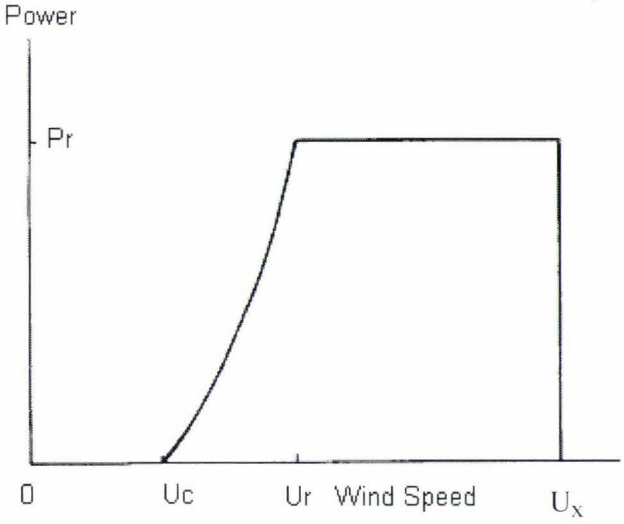


Fig. 3.7: General Configurations of Horizontal-Axis Wind Turbines (HAWTs) *(Spera, 1997)*

Although vertical axis wind turbines (VAWTs) offer some advantages such as simpler control system (e.g. the question of aligning the turbine for changing wind direction does not arise) and ease of maintenance (e.g. major equipment such as the gear box and the generator are located at the ground level) over horizontal axis wind turbines (HAWTs), the latter continue to dominate the world wide wind turbine market. In any case it has been found uneconomic to produce small VAWTs and there aren't any in production of late (Spera, 1997).

Shutting down a turbine in high winds in the case of a small HAWT, can be easily realised by allowing the turbine to furl by turning the rotor (blades) parallel to the wind direction naturally.

The "cut-in wind speed" (Uc) is the speed at which the wind turbine starts to produce power (Fig. 3.8) while the "cut out wind speed" (U_X) is the wind speed at which the machine shuts down to prevent damage. The "rated wind speed" (Ur) is the wind speed at which the "rated power" is achieved, where generally the turbine performance is maximised (MUERI, 2003). Typical Uc, Ur and U_X, values of a small wind turbine are 3.0 m/s, 14.0 m/s and 16.0 m/s and 24.0 m/s respectively (Spera, 1997).



A proper match between wind power curve characteristics and frequency distribution of the local site wind speed is necessary to maximise annual energy generation. A rule of thumb is to select a turbine whose rated speed is 1.5 times the annual average wind speed of the site (De Montfort, 2003).

Fig. 3.8 The Power Curve of a typical large[3] modern wind turbine
(MUERI, 2003)

In many systems, the power output above the rated wind speed is mechanically or electrically maintained at a constant level by shedding excess wind power, allowing more stable system control (AWEA, 2003). Stall regulation is one modern technique of mechanical regulation where the rotor is aerodynamically designed such that its properties limit the torque produced at high wind speeds. Current research is also directed in designing wind turbines for low wind regimes (DOE, 2002), in particular for wind power class 3 (Table 3.1) involving greater wind turbine rotor hub heights.

Wind measuring devices (anemometers) are typically installed at a 10m height above ground, in keeping with the industry reference height of 10m for wind measurements. Usually the hub of a wind turbine rotor will be at a higher elevation (larger the turbine,

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[3] *Larger wind turbines have more sophisticated turbine control systems to achieve the operating characteristics close to what is depicted in Fig. 3.8. In a strict sense this is characteristic of an idealised wind turbine.*

higher the elevation) to take into account the positive correlation of wind speeds with height. One established relationship between the two variables is based on the power law. According to this law, the wind velocity V at any elevation H (above ground) is given by the equation (Gipe, 1999):

$$V = V_0 \, (H/H_0)^{\alpha},$$

where V_0 is the velocity at any reference elevation H_0 (where $\alpha>0$). The coefficient α is referred to as the roughness exponent (also called wind shear exponent) which is a function of the roughness of the terrain. For example the value of α, which is typically 0.1 on water or ice increases to 0.14 on low grass or steppe (Gipe, 1999).

Wind power class	**Height of wind measurement: 10m (33 ft)**		**Height of wind measurement: 30m (98 ft)**	
	Wind power density (W/m^2)	**Wind speed (m/s)**	**Wind power density (W/m^2)**	**Wind speed (m/s)**
1	0-100	0-4.4	0-160	0-5.1
2	100-150	4.4-5.1	160-240	5.1-5.8
3	150-200	5.1-5.6	240-320	5.8-6.5
4	200-250	5.6-6.0	320-400	6.5-7.0
5	250-300	6.0-6.4	400-480	7.0-7.4
6	300-400	6.4-7.0	480-640	7.4-8.2
7	400-1000	7.0-9.4	640-1600	8.2-11.0

Table 3.1: Wind power classification used in US research *(Manwell, 2002)*

The electrical interface required between the wind turbine and grid supply varies from design to design. The modern trend among small wind turbine manufacturers is to produce wind turbines with variable frequency alternators (Manwell, 1998). The AC supply produced by the alternator of such a wind turbine should be rectified and inverted via a grid interactive inverter before grid connection. Apart from variable frequency alternators, manufacturers also use synchronous generators (which are essentially constant speed machines) and induction generators. Induction generators have lower efficiency than synchronous generators but natural torsional damping is provided through induction generator slip, which reduces the cost of the power transmission system (Spera, 1997).

Christchurch based New Zealand manufacturer Wind Flow Technology Limited is using synchronous generators in their new design to take advantage of increased efficiency with a patented 'torque limiting gear box' to achieve the necessary damping and control. Wind Flow Technology also opt for a two bladed HAWT design (as opposed to the more common 3 bladed design) to reduce turbine fatigue load and material and production costs. Their 500kW design currently under evaluation is claimed to be 20% to 50% less costly than three bladed machines available from competitors in the world market today.[4]

Like any rotating machine, a wind turbine needs maintenance, during its designed operating life, which is typically 20 years. The actual lifetime of a wind turbine depends both on the quality of the turbine and the local climatic conditions such as the amount of turbulence at the site and the resulting fatigue loads (Dan Wia, 2003).

Small turbines are designed to have very few moving parts and hence require less regular maintenance compared to their larger plants. In addition to regular maintenance, wind turbines could come across forced outages resulting in unscheduled maintenance, owing to failure of mechanical, electrical or power electronic components (Lynette and Gipe, 1994). Obviously all the major maintenance work will have to be carried out by outside contractors.

A study done on the 5000 wind turbines installed in Denmark since 1975 showed that newer generations of turbines have relatively lower repair and maintenance costs than the older generations. The study compared maintenance costs at different phases of the life cycles of turbines (i.e. at the same age) of different generations from the early 1970s to late 1990s. Older Danish wind turbines between 25-150 kW rated power had annual

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[4] *However this capacity is far too large to be interconnected to a rural distribution grid. See section 2.8 for issues in connection with interconnection of renewable DG to weak lines/grids.*

maintenance costs on average of around 3% of the original turbine investment cost, while projected annual costs of the newer turbines were around 1.5% per year of the original turbine investment (Dan Wia, 2003).

3.2.2 The Environmental Issues Related to Wind Turbine Generators (WTG)

Although wind turbine generators have relatively little impact on the environment compared to other conventional power plants, there is some concern over the noise produced by the rotor blades, electromagnetic wave interference (e.g. interference to radio, TV & microwave communication signals), aesthetic (visual) impacts and mortality of birds (by flying into the rotors). Most of these problems have been resolved or greatly reduced through technological development and industrial standards[5] or by properly siting the plants (Spera, 1997). According to Gipe (1999), the only major environmental concern in connection with small wind turbines is the possible noise disturbance to neighbours, when these are sited in or close to urban areas. Siting of small wind turbines in a rural New Zealand setting should not be a major externality issue that needs addressing at the present point in time.[6]

3.2.3 WTG Economics

The world-wide demand for wind turbines has been growing rapidly since the early 1980s. The total global wind based installed capacity at the end of 2002 was 32,000 MW. USA and several European countries headed by Germany, Spain and Denmark have been successful in developing wind based capacities in power generation. Over the last five years, the average annual growth of wind based turbine generators world-wide has been in the region of 30-40%. This has been propelled by technological advances in the wind-generated designs and state incentives (NREL, 2002). For example it has been reported that 14,000 small wind turbines were sold in USA for domestic use in 2001. The major application of these being to serve as grid connected distributed resources to help offset

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5. *For example NZS 6808:1998 is applicable for Australian and New Zealand installations for assessment and measurement of sound from wind turbine generators.*

6. *Even for small wind turbines, according to the provisions of the Resource Management Act 1991 (RMA), the consent of the local governing body (district councils for rural areas and city councils for urban areas) has to be sought in connection with the use of land (commonly referred to as a land use resource consent) to erect the unit, if the local governing body's environment plan calls for such a consent. Almost all district/city council plans call for a land permit (ME, 2003). However, the resource consenting procedure and its associated costs are not considered to be major barriers for the uptake of small wind turbines in New Zealand.*

electricity bills from the utility company. US consumers have discovered that electricity generated by small wind turbines in places with a good wind resource are competitive at the current retail utility rates. This is especially true for states that have small-wind financial incentives, including rebates and price buy-downs (NREL, 2002).

However, unlike PV, for wind technology economies of scale apply, meaning larger machines are able to produce electricity at a much lower cost. For example in the USA, in some areas, large-scale wind energy projects yield levelised cost of wind electricity in the range of 0.04 – 0.08 US$/kWh making large wind projects competitive with conventional power plants (AWEA, 2003).

Considering the fact that progress ratio for wind technology is as good as PV technology (80% approx.), one could expect small wind turbines to be a viable DG option in the future for most locations in New Zealand. Application of small wind turbines until recently has been in remote area stand-alone power systems or for battery charging and water pumping functions in developing countries.

Advancing the technology is one way to make small wind technology more cost effective. NREL researchers believe that by developing and incorporating advanced technology for small wind turbines, by 2007, the levelised cost of energy could be reduced to US$ 0.10–0.15/kWh for wind turbines designed to class 3 winds (Table 3.1).

3.3 MICRO-HYDRO SYSTEMS

3.3.1 Micro-Hydro Performance

Water turbines used for micro-hydro applications (< 100 kW) are scaled-down versions of turbines used in conventional large hydro developments (Penche, 1998). Electric power is produced when potential energy of a mass of water, flowing in a stream with a certain head is converted to electrical energy through appropriate electromechanical gear (Penche, 1998). This concept is illustrated with respect to a typical hydro power station layout (Fig. 3.9).

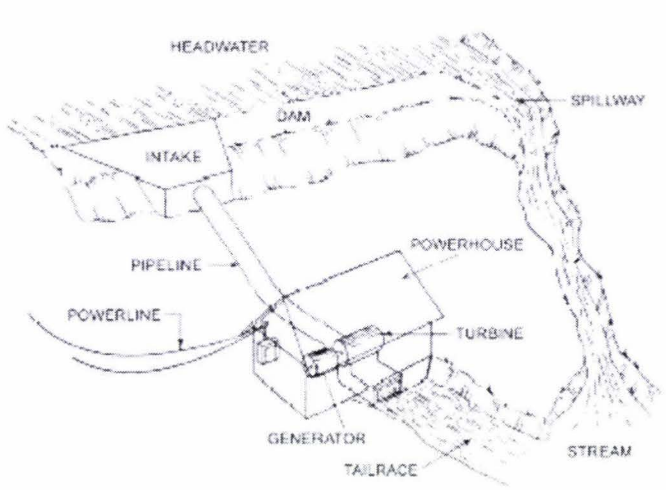

Fig 3.9. The layout of a micro-hydro power station[7]
(BCMAF, 1985)

The hydraulic power of water is equal to the rate at which its potential energy is converted. That is;

$$P_{\text{hydraulic}} = d/dt\,[(\rho_w V)gH] = \rho_w gH\,(dV/dt) = \rho_w gHQ \qquad \text{Eq. 3.3}$$

where $P_{\text{hydraulic}}$ = hydraulic power (W)

ρ_w = density of water (kg/m^3)

V = volume of water that causes the potential energy (m^3)

g = gravitational acceleration (m/s^2), which is 9.81 m/s^2.

Q = water flow rate (m^3/s)

H = Total net water head available (m)

Due to losses taking place in the system, the turbine would not capture all the available hydraulic energy. If η_{turbine} and η_{gen} are the efficiencies[8] of the turbine and the electrical generator (including efficiency of any transmission system available) respectively, then electrical power output from the generator is given by;

$$P_{\text{electrical}} = \eta_{\text{turbine}} * \eta_{\text{gen}} * P_{\text{hydraulic}} = \eta_{\text{turbine}}\,\eta_{\text{gen}}\,\rho_w gHQ \qquad \text{Eq. 3.4}$$

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[7] *This figure actually depicts a high head hydropower scheme, which need not be the case always.*

[8] *Efficiency also drops when water is conveyed via the piping system through to the turbine, due to friction and turbulence. These hydraulic losses are typically included in the total net water head H, which is the total head net of the hydraulic losses.*

Substituting 1000 for ρ_w and 9.81 for g and[9] combining the two efficiencies to one overall efficiency (denoted as η), the power output (electrical) from the plant in kW could be denoted as[10]:

$$P_{out} = \eta 9.81HQ \qquad \text{Eq. 3.5}$$

Often small hydro systems are classified into two categories. A system in the 100 kW to 1 MW range is referred to as a "mini-hydro" and system less than 100 kW is referred to as a "micro-hydro" (NRCan/CEDRL 2002). Based on this classification, micro-hydro plants are the ones that are suitable for connection to a rural New Zealand distribution line[11].

Small-hydro plants[12] require little maintenance over their useful life, which can be well over 50 years. Normally, operation and routine maintenance of a small-hydro plant can be handled easily by one part-time operator (e.g. cleaning the intake screen). Periodic maintenance of the larger components of a plant will usually require help from outside contractors (NRCan/CEDRL 2002).

Generally, small-hydro projects built for application at a remote community are run-of-river developments. "Run-of-river" refers to a mode of operation in which the hydro plant uses only the water that is available in the natural flow of the river. It implies that there is no water storage or flooding and that power fluctuates with the stream flow. The cost of large water storage dams cannot normally be justified for small waterpower projects and consequently, a low dam or diversion weir of the simplest construction is normally used.

Specific speed is one of the useful parameter used in connection with turbine design, which represent the turbine characteristics. The specific speed N_s of a turbine is given by (Bhattacharya, 1984);

$$N_s = N \sqrt{P} / H^{1.25} \qquad \text{Eq. 3.6}$$

---

[9] *For all intents and purposes the density of water and the gravitational acceleration can assumed to be constant values; of 1000 kg/m3 and 9.81 ms^{-2} respectively.*

[10] *It can also be proved that input electrical power required to pump water to an upper reservoir constituting a total head of H metres is given by, $P_{in} = (1/\eta)9.81HQ$. The hydraulic power in this instance is multiplied by the inverse of the overall system efficiency $(1/\eta)$ to take into account the energy conversion losses. The equation $P_{in} = (1/\eta)9.81HQ$ is used in the pumped hydro model (Eq. L.21, Appendix L).*

[11] *Please see Appendix-E for typical feeder impedance data for a 11 kV rural electricity feeder.*

[12] *The phrase 'small hydro' is used more in relation to the kW installed capacity than the physical size (dimensions) of a plant. The latter can vary considerably depending on the operating head. A low head turbine is considerably larger than a high head plant with the same kW capacity to accommodate a greater volume (discharge) of water.*

Specific speed is defined as turbine (runner) speed of a geometrically similar turbine (to the original turbine operating under a head H at a speed N rpm) delivering 1 unit of power under a hypothetical unit head. Geometric similarity refers to reduction in size of a prototype maintaining a fixed ratio for all homogeneous lengths (Penche, 1998).

As different types of turbines operate optimally under different operating conditions, specific speed is used as a benchmark in selecting the most appropriate turbine for a given operating condition. The most appropriate turbine in this instance refers to optimisation from an efficiency viewpoint. Engineers have also attempted to fit regression curves linking the operating net head (H) and the specific speed (Ns) for such optimized designs in respect of different turbine types. These results are shown in Fig. 3.10 and Table 3.2.

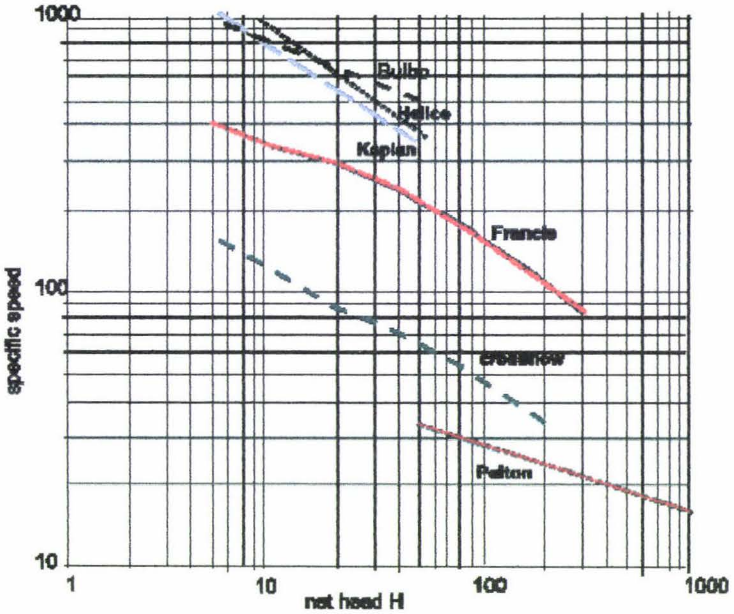

Fig. 3.10 The specific speed and net head of different type of turbines, optimized from an efficiency viewpoint.
(Penche, 1998)

Turbine Name	**Relationship**
Pelton (1 jet)	$Ns = 85.49/ H^{0.243}$
Francis	$Ns = 3763/ H^{0.854}$
Kaplan	$Ns = 2283/ H^{0.486}$
Cross flow[13]	$Ns = 513.25/ H^{0.505}$
Propeller	$Ns = 2702/ H^{0.5}$
Bulb	$Ns =1520.26/ H^{0.2837}$

Table 3.2: Established statistical relationships between specific speed and net head for different turbine designs.
(Penche, 1998)

Using the equation in Table 3.2 for the limiting specific speeds depicted in Fig. 3.10, the optimum operating net head range for each type of turbine can be specified as follows:

Kaplan and Propeller:	$2 < H < 40$
Francis:	$10 < H < 350$
Pelton:	$50 < H < 1300$
Cross Flow:	$3 < H < 250$
Turgo:	$50 < H < 250$

---

[13] *Cross flow turbines are sometimes referred to as Michell-Banki turbines; named after the inventors as in the case of most other turbine types.*

3.3.2 The Economics of Micro-Hydro

Since micro-hydro installations are very site specific and labour intensive (the owner/operators may do much of the labour), costs can vary widely. The topography of the site, the location in relation to the power demand, the availability of used equipment and the ability of the individual to perform the labour, affect costs. The same could be said about the unit size (cost per kilowatt goes down as output goes up), the head (high head sites are generally cheaper than low head sites of equal output) and the amount of site work required (BCMAF, 1985).

Micro-hydro is traditionally considered to be feasible only when grid electricity is very costly, either as remote area power supplies or where there are high line charges. Based on Canadian estimates, the up front costs for a 10 kW micro hydro scheme can range from NZ$ 800 to over NZ$ 5000 per kW. However interest in grid connected micro hydro with storage capacity and small pumped hydro systems have grown due to the value addition of such schemes for rural distribution networks in providing firm energy[14]. The financial viability of micro hydro schemes geared to provide firm energy is greatly improved if existing ponds/wires could be harnessed (this reduces civil engineering costs greatly) and ordinary water pumps could be used as turbines (this cuts down on the electro-mechanical equipment costs greatly). Some of these aspects are covered in section 3.4.

3.3.3 The Environmental Issues Related to Micro-Hydro

The environmental impacts associated with micro-hydro developments can vary significantly depending on the location and configuration[15] of the project. In New Zealand, almost invariably, some form of resource consent will have to be sanctioned from the local and regional authorities to implement a hydro project. The statutory provision that stipulates legal requirements in respect of environmental risks in respect of projects which have an environmental impact on air, water and land is the Resource Management Act of 1991 (RMA). This act provides for the use of natural and physical resources while maintaining environmental sustainability. Environmental decision-makers are those most

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[14] *The only limitation in using a centrifugal water pump to run as a turbine in a medium head application is its inability to operate efficiently at different discharge levels. It is easy to design a standard water pump to operate as a turbine efficiently under a fixed head and fixed discharge (Penche, 1998). This is not a limitation for grid connected applications.*

[15] *For example the effects on the environment of developing a small hydro plant at an existing dam are generally minor and similar to those related to the expansion of an existing facility.*

closely affected by the use of that resource (e.g. residents in the neighbourhood). They are the party who have to deal with the effects and who best understand the environmental issues at stake. Decisions are usually made at a regional or district level, although sometimes central government may need to step in (ME, 2003).

According to the provisions of the Act, the regional and district/city councils have to identify the environmental risks in their area, and develop a plan for responding to those threats. The role of central government is to provide national guidance and standards for environmental management (ME, 2003). In general, project activities that are to do with subdivision or coastal use or with discharges to air and land, or with water use, the project developer will need to obtain a resource consent from the regional council.[16] As regards the land use, noise and subdivisions, the applicable authority is the district and city councils. [17]

Having to obtain a water use resource permit to take dam or divert water and having to obtain a land use permit to build a structure on a river or lake bed (and possibly disturbing clear vegetation from erosion prone land) for hydro projects does mean that costs related to these externalities have to be taken into account for DG models using micro hydro and pumped hydro applications. For example, with regard to Horizons.mw[18], for a notified resource consent, it costs $ 550.00 for the application plus overhead charge based on the regional council's staff charges ranging from $ 115.00 per hour for the highest paid employee to $ 55.00 per hour for the lowest paid employee.

3.4. LOW COST PUMPED HYDRO SYSTEMS

"Pumped storage" development, which is a special kind of a storage development, is where water is "recycled" between downstream and upstream storage reservoirs. Water is passed through turbines to generate power during peak periods and pumped back to the upper reservoir during off-peak periods (Fig. 3.11). The storage requirements (hence the cost of civil works) will be minimal as water is frequently recycled between the upstream

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16. *The only exemption being if the regional plan specifically permits the specific activity (ME, 2003). For micro hydro projects, in general, there are no exemptions.*

17. *To be specific, according to the RMA, a land use resource consent is only necessary if the district/city council plan requires a permit for a specific activity (ME, 2003). This is the case invariably, for hydro and wind turbine projects.*

18. *Horizons.mw is the trading name of the Manawatu-Wanganui regional council.*

and downstream reservoirs. Pumped storage systems have special significance because of the availability of (short term) energy storage capability and thus enhancing dispatchable capacity (supply of capacity on demand) due to generation of electricity during peak periods during which the price of electricity is expected to be at a premium.

Pumped storage systems have traditionally been associated with high capacity plants. However, of late use of centrifugal water pumps as turbines has caught the attention of micro hydro designers. It has been found that use of pumps as turbines, if engineered correctly, can be very cost effective and efficient.

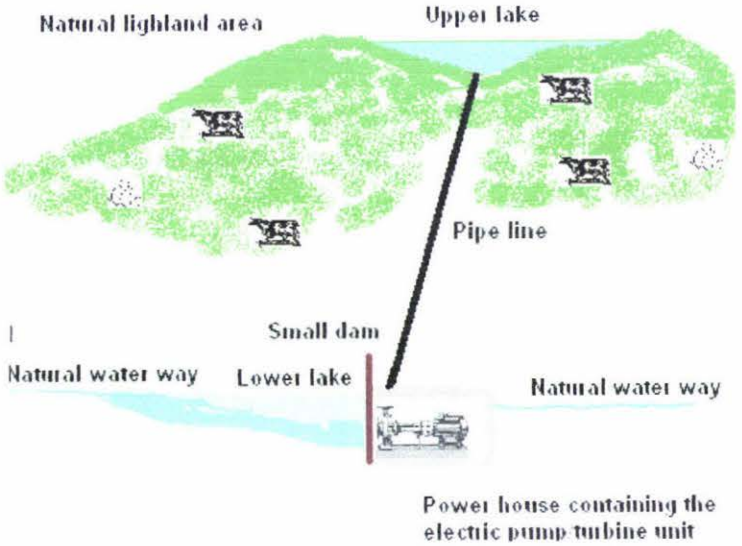


Fig. 3.11: Impression of a low cost New Zealand rural pumped hydro project

The concept is to use a normal centrifugal water pump, reverse engineer the pump curve for running the pump backwards efficiently, and run the penstock into the normal discharge outlet. In effect, the pump runs backwards, and acts as a turbine. Efficiencies as high as 85%-90% have been documented (Williamson, 2002). In one case in British Columbia, Canada a particular water pump was installed on a head of 83m, producing up to 200 kW. The cost of the unit was less than Can$ 25 per installed kW. Several other cases have been reported from countries such as UK, USA and Pakistan (NTU, 2003). Research show that these pumps are most efficient between 13m and 75m of gross head.

The engineering challenge of the use of a water pump system is the reverse engineering of the pump's operating characteristics. Research based on testing several centrifugal pumps has shown that just any pump will not work efficiently since the characteristic curves of the pump does not apply in the reverse direction as a turbine (Williamson, 2003). Another

T&D support in Fig. 3.13 (page 65) refers to supply of firm capacity (or firm energy) to the transmission and distribution network when required (also see paragraph 1 of page 27 and section 2.6.1.2).

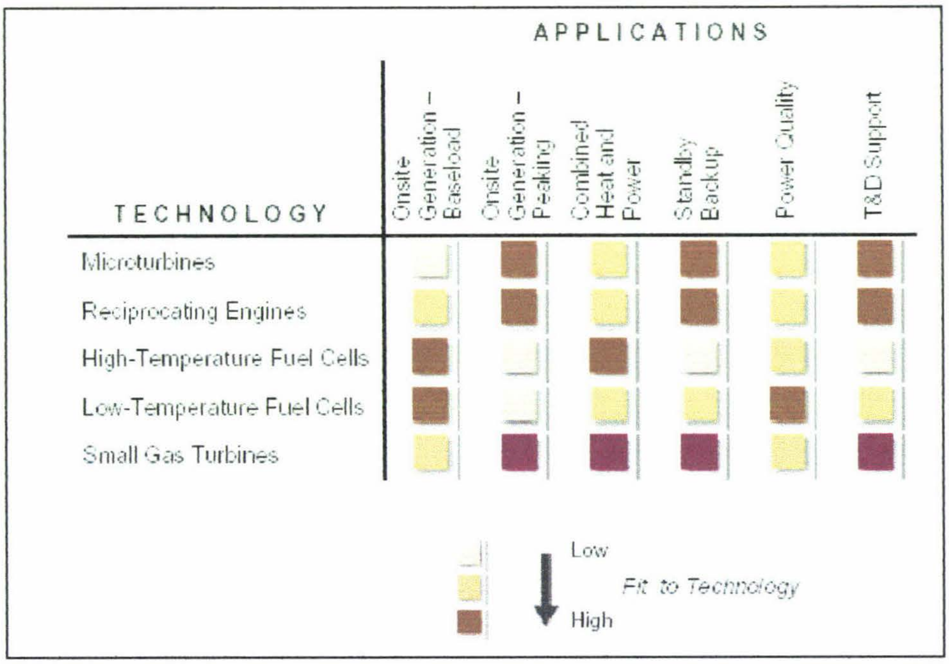
major advantage of this system is the use of the pump's induction motor as an induction generator, which eliminates the complication of synchronising a small synchronous generator to the grid or use of a costly inverter to connect a variable frequency alternator, which is the case for a conventional micro hydro system. Since grid supply is essential for the operation of the induction generator (to magnetise the core), it de-energises in the event of a grid failure, thus exhibiting anti-islanding properties.

3.5 FUELLED GENERATING SETS

Fuelled generating sets (FGS) are energy conversion devices that transform chemical energy contained in fuels to electrical energy. Reciprocating engines, micro turbines, small gas turbines, Stirling engines and fuel cells come under this category.

One advantage of using a FGS in a DG configuration is the possibility of using these (in most cases) for a combined heat and power (CHP) applications due to availability of residual heat for heating (e.g. process heating, space heating) or cooling (e.g. vapour ammonia refrigeration) applications, thus improving the overall thermal efficiency significantly.

The other advantage is that since fuel can be stored, FGSs can supply energy on demand for standby operation or peak lopping, for distribution support (Figure 3.12).



	APPLICATIONS					
TECHNOLOGY	Onsite Generation – Baseload	Onsite Generation – Peaking	Combined Heat and Power	Standby Backup	Power Quality	T&D Support
Microturbines	⬜	🟫	🟨	🟫	🟨	🟫
Reciprocating Engines	🟨	🟫	🟨	🟫	🟨	🟫
High-Temperature Fuel Cells	🟫	⬜	🟫	⬜	🟨	⬜
Low-Temperature Fuel Cells	🟫	⬜	🟨	🟨	🟫	🟨
Small Gas Turbines	🟨	🟪	🟪	🟪	🟨	🟪

⬜ Low
🟨 *Fit to Technology*
🟫 High

Fig. 3.12: Application-technology match of different FGS technologies *(Energy International Inc., 2003)*

3.5.1 Reciprocating Engines

Although reciprocating engines can be fuelled by a variety of liquid and gaseous fossil fuels and biofuels[19], in a New Zealand context, at present the only economically viable fuel for DG applications is diesel.[20] Diesel standby generating sets are the world's fastest selling DG technology with a proven and rugged performance. It is also the DG technology with the least up front cost (Lowrey, 2002).

However compared to renewable DG units, the operation and maintenance (O&M) costs of diesel gen sets are considerably high. The operation cost of a diesel gen set for the most part includes cost of fuel, and any labour used in operating the unit. Diesel generator maintenance can be subdivided into a number of categories. During the lifespan of about 25,000 operating hours, there is the regular changing of oil and oil filter (approximately every 250~400 operating hours); a top overhaul needs to be carried out after around the 6000 operating hours in which the turbocharger, injectors, cylinder heads and head gaskets are inspected and tested; and a major overhaul needs to be carried out after around 15,000 operating hours, which involves the stripping and reconditioning of the whole engine[21] (Pryor, 2002).

Typically, diesel engines loaded at less than 30% will not achieve a good operating temperature resulting in poor combustion and degrading of lubrication oil. Hence this constraint is normally incorporated when designing RAPS and DG control algorithms (Hazel, 2000).

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19. *Biofuels such as biodiesel and bioethanol are renewable fuels. At present cost of production of bio diesel and bioethonol far exceeds the ex-refinery price of diesel. There is continuing research on this fuel world wide (Sims, 2002).*

    In New Zealand biodiesel could be synthesised from oil seed rape or inedible tallow, a by product from the meat industry. The fuel can be used as a direct substitute for diesel with no engine modification. The operational performance of bio diesel is nearly identical to diesel (Sims, 2002).

    With Carbon taxation for fossil fuels and efficient product development, biodiesel could become a viable alternative for operating generator.

20. *In smaller capacity ranges, petrol generator sets also compete with diesels. In other countries, natural gas is used as a substitute to petrol, which is costly.*

21. *Typically, a major overhaul costs about 60-70% of the initial cost of the generator set, while a top overhaul costs about 30-40% of the initial cost.*

Fig.3.13 depicts the input-output characteristics (to be specific the normalised[22] fuel consumption Vs normalised prime power rating) of a diesel generating set. As indicated in Fig. 3.13, clearly, the part load performance of a diesel generating set is not satisfactory.

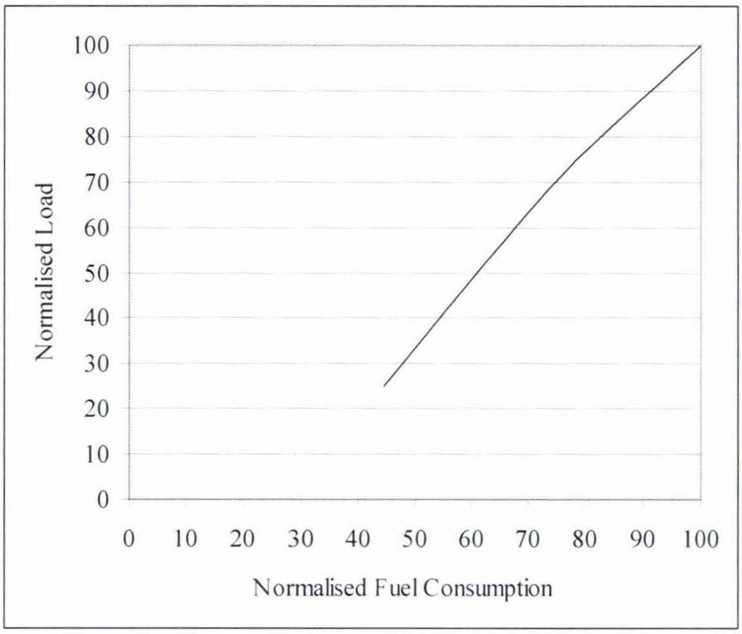

Fig. 3.13: Input-output characteristics of a diesel generating set

Standby generator sets are typically rated based on their use in standby applications. The generator standby rating, which is typically what is mentioned in the name plate, is the maximum power rating the generator is able to deliver during the duration of a utility outage. This is typically limited to 2 hrs out of a 12-hr period. The generator set supplier assumes that because the generator set is not paralleled to a utility source, the actual load on the generator set will vary somewhat over the time that it is running. Sustained operation at the standby rating level shortens the life of the engine and may even cause it to malfunction. This gives rise to including an additional power rating, namely the prime power rating. If a generator set is expected to be used in an utility plant (such as in an on-site interruptible application, grid connected DG), then it is important to size the generator set based on its prime rating. Generally, the prime rating of a generator set is approximately 10% less than its standby rating. Operating at the prime rating allows the engine life to be significantly improved (Olson, 1996).

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[22] *A normalised parameter is a parameter rescaled by dividing the actual value by the rated value (in Fig. 3.13 it is expressed as a percentage). Working with normalised parameters enables a researcher to detach from the specifics of the operating characteristics of generating sets manufactured by different manufacturers for different kW capacities. Fig. 3.13 is based on the data specified by the manufacturer M/S Cummins for a 400V, 50HZ standby generator with a prime capacity of 18kW*

In theory, since the electrical generators used in standby units are synchronous alternators, there exists the possibility of paralleling the unit to the grid directly via a synchronous scope. However for smaller units (< 250 kW) it has been found that the hardware costs[23] of the paralleling gear (synchronous scope and the electronic circuits) far exceeds the benefit gained by being able to transfer the 100% output of the alternator (Olson, 1996).[24]

3.5.2 Fuel cells

A fuel cell is an electrochemical device that converts the chemical energy of a fuel directly into electrical energy. All fuel cells consist of two electrodes (anode and cathode) and an electrolyte (usually retained in a matrix). Fuel cell operation is analogous to a battery except that the reactants (and products) are not stored, but continuously fed to the cell (ECW, 2000). Figure 3.14 shows the flows and reactions in a simple fuel cell.

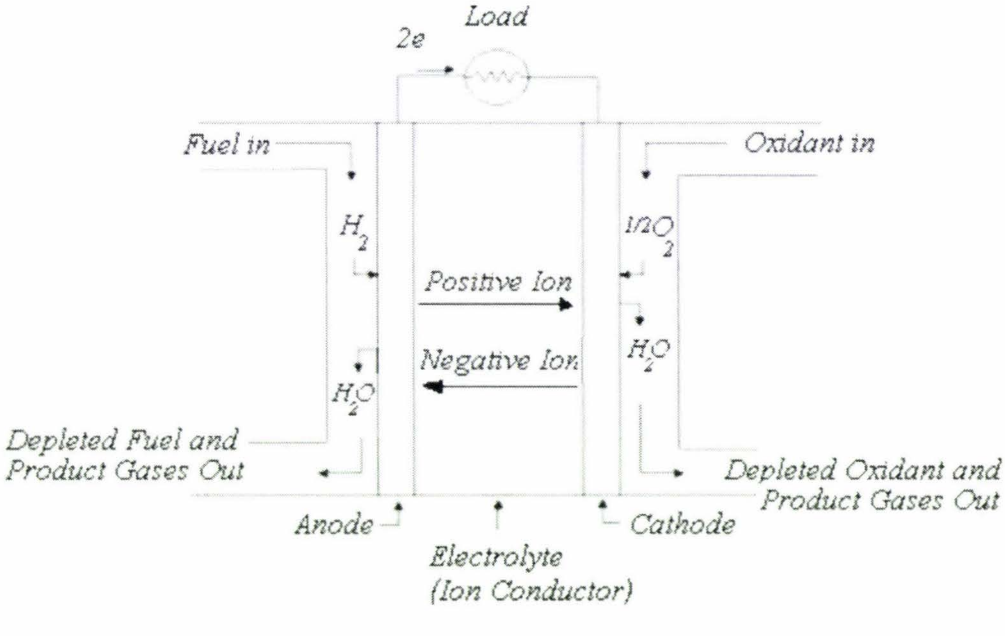

Fig. 3.14: The flows of reactants of a simple fuel cell
(Hirschenhofer, 1998)

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[23] *Apart from the synchronizing, in paralleling a generator directly to the grid, complications also arise with respect to speed governing and voltage control. This is because standby generator sets are normally designed to operate independently (isochronous mode), adjusting the fuel flow rate with varying load to lock the frequency at 50HZ, while maintaining the supply voltage via. the voltage regulator. When the generator set is in parallel with the utility supply, since the utility supply is much stronger, it will determine the system frequency and the system voltage. The governor will therefore be used to control the active power output of the engine, and the voltage regulator will control the reactive power output of the generator. The generator set must know in which configuration it is operating in order to be able to switch the governor and voltage regulator operation from frequency and voltage control (isochronous operation) to active and reactive power control (parallel operation). Auxiliary contacts from the switchboard are normally used to provide the necessary information to the generator governor control circuit (Hazel, 2000).*

[24] *The standard procedure for coupling a small diesel generator set to the grid is by rectifying the output to DC and inverting it to AC via a grid interactive inverter. This means about 20% of the generator output is lost when conveyed though the power conditioning devices through to the grid (see section 8.2.4 for further details).*

Although fuel cells were first invented in 1839, as a technology it remained dormant until the late 1950s when NASA engineers used precursors of today's fuel cell technology as power sources in spacecraft (ECW, 2000).

Unlike ordinary combustion, fuel (hydrogen-rich) and oxidant (typically air) are delivered to the fuel cell separately. The fuel and oxidant streams are separated by an electrode-electrolyte system. Fuel is fed to the anode (negative electrode) and an oxidant is fed to the cathode (positive electrode). Electrochemical oxidation and reduction reactions take place at the electrodes to produce electric current. The primary product of fuel cell reactions is water (ECW, 2000).

Currently, fuel cell research efforts are driven mainly by the automotive industry in a quest to use clean fuel economically. However the fact that hydrogen is the fuel of choice in energy efficient fuel cells and that it is the least complex and most abundant element in the universe, will trigger many more applications. It is argued that using hydrogen as fuel can fundamentally change mankind's relationship with the natural environment. It is nearly an ideal energy carrier, and will play a critical role in a new, decentralised energy infrastructure that can provide power not only to vehicles but to homes, commercial buildings and industries. Hydrogen boasts many important advantages over other fuels in that it is non-toxic, renewable, clean to use, and packs much more energy per unit mass (RMI, 2003).

There are at least six different fuel cell types in varying stages of development, four of which are receiving the most attention. In general, the electrolyte type and operating temperatures differentiate between fuel cells. Listed in order of increasing operating temperature, the four fuel cell technologies currently being developed are (ECW, 2000):

Proton exchange membrane fuel cell (PEMFC) - 80^0C
Phosphoric acid fuel cell (PAFC) - 200^0C
Molten carbonate fuel cell (MCFC) - 650^0C
Solid oxide fuel cell (SOFC) - 1000^0C

Being a new technology the upfront cost of DG units using fuel cell technology is too high for residential and commercial use. So far, no manufacturer has been able to reduce the price of a 5kW fuel cell below US$30,000 (i.e. US$ $6,000/kW). Most market research indicates that consumers won't be interested in the technology until it drops much closer to the price of a petrol-powered home generator, at around US$ 250/kW (Wardell, 2003).

3.6 LEAD-ACID STORAGE BATTERIES

Although lead acid battery applications are more common on remote area power supply (RAPS) systems to complement intermittent renewable energy, in theory, as a storage device, it can provide valuable grid support (peak lopping). From an economic stand point, if price signals are such that peak electricity prices are significantly high (as opposed to off peak price) or payments are made by a lines company for capacity supply during critical peaks periods (faced by the lines company), battery storage technology could be a viable technical option, with the appropriate time of use metering.[24,25]

For distributed resource (DR) applications, the batteries of choice are deep cycle lead acid batteries, which have heavy grid structures and additional features to produce a long operating life. Starting-lighting-ignition (SLI) batteries used in automobiles are considered unsuitable due to their construction. A deep cycle lead acid battery has thicker and consequently fewer plates than a SLI battery of the same dimensions. The more robust plate construction allows it to be discharged deeper and more often than an automotive starting battery before the lead in the plates disintegrates. Due to having more plates, therefore more surface area exposed to the sulphuric acid, it is able to supply greater amperage for a short period than a deep cycle battery, which is essential for the starting motor of an automobile. However, since the plates are thinner the battery plates do disintegrate after fewer discharge cycles (Winlow, 2001).

Due to exclusive applications in RAPS systems, several manufacturers have advanced the lead acid stationary battery technology. One such recent technical advancement is special design of batteries that require regular discharging to relatively lower levels followed by charging partially or completely (Pryor, 2002).

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24. *The operation of a 40MWh lead-acid battery plant in Chino, USA is one example where the technical feasibility of battery storage has been successfully demonstrated on a large scale, for grid support (ACRE, 2003). Apart from the life cycle cost of batteries, the cost of power conditioning equipment (i.e. rectifiers and inverters) also determine the economics of batteries for peak lopping.*

25. *Currently the research efforts involving battery storage devices are directed towards newer technologies involving advanced batteries which incorporate different electrode types and electrolytes.*

Two battery parameters that are relevant for DR systems design are the battery capacity and the cycle life.

The battery capacity defines how much energy can be extracted from the battery, at a given discharge rate. It is generally measured in Ampere-hours (Ah) and is denoted by its discharge rate Cn. The Cn value of X Ah denotes that the battery is capable of supplying a constant current of (X/n) amps for n hours before being classed as flat or fully discharged (Pryor, 2002). The nominal rating of a battery is its capacity at the C_{100} discharge rate (Fig. 3.15).

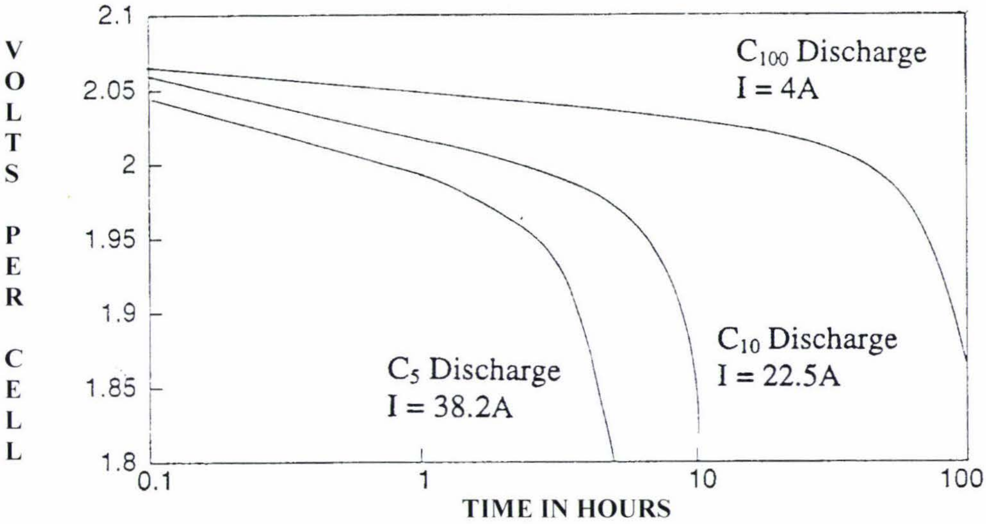

Fig. 3.15: The discharge curve of a deep cycle battery with a nominal rating of 400 Ah. *(Pryor, 2002)*

At a moderate discharge rate (say C_{25}) it can be assumed that the battery voltage remains approximately constant over a discharge interval that is not long enough (say 4 hours at C_{25} rate) for the battery to attain a low discharge depth .[26]

The cycle life of a battery in a DR application depends on how often it is cycled and to what depth of discharge it is taken. Depth of discharge (DOD) is defined as how much current (hence energy) has been extracted from the battery compared to its capacity at those conditions (Pryor, 2002). Accordingly a fully charged battery has a DOD of 0% while a fully discharged battery has a DOD of 100%. Literally all deep cycle battery manufacturers provide information as to how cycle life (i.e. the number of cycles that a battery can undertake before it is classified as unusable) varies with depth of discharge (Fig. 3.16).[27]

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26. *This observation was used for making a simplifying assumption in the mathematical models on lead acid batteries (Eq. L.17 of Appendix L). The assumption is justified on the grounds that peak lopping is conducted over 2-3 hours only per day, once a day (i.e. one charge cycle per day) at C_{25} discharge rate.*

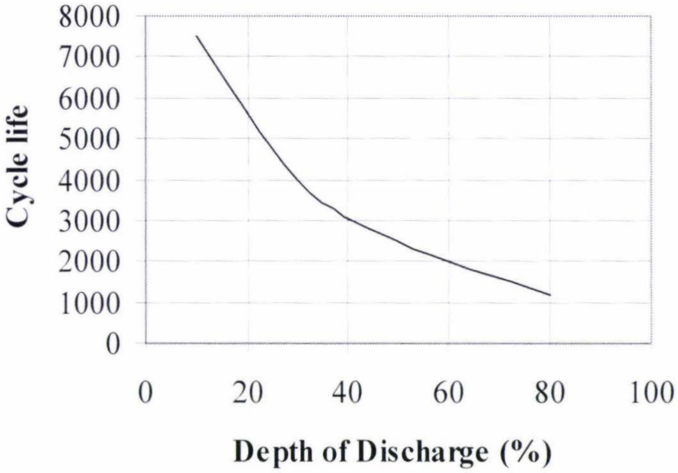

Fig. 3.16: Cycle Life Vs Depth of Discharge of BP Solar PVSTOR battery models

The performance of the battery charging system also makes a significant contribution towards the life cycle cost of a battery system as a peak lopping DR. There are three common methods of battery charging.

- Constant voltage charging is a process where the voltage across the battery is held constant at the level required by the battery in its fully charged state. The current is large at first[28] and tapers off as the battery becomes charged (Pryor, 2002).

- Constant current charging is a process that involves applying a supply voltage that is much higher than the battery voltage and limiting the current flow by placing a resistor in series with this applied voltage. The currents in the charging process vary much less in this method of charging (Pryor, 2002)[29].

- Taper current charging is a process where the current is high at the start of the charge and tapers off to a low current at the end. The drop of current occurs because of the increase in voltage of the battery as the battery charge level increases. The initial current is generally limited to the 4 or 6-hour rate (Pryor, 2002).

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27. *In a grid connected DR context, if one makes the assumption that the role of batteries as a peak lopping device is to inject a constant current for a fixed period of time each day , battery life (and hence the replacement interval) could be determined using a linear relationship.*

28. *The current in the early stages may need to be limited to prevent excessive levels of current being forced into the battery (Pryor, 2002).*

29. *As far as the initial cost is concerned constant current charging is the cheapest due to simplicity of the control system.*

In addition to the above, in most battery banks it is generally important to provide an equalisation charge on a regular basis, say once a fortnight or once a month. This involves raising the charging voltage above the normal level and maintaining this charging until all the cells in the battery are fully charged. This removes any variations between the states of charge of the component cells and batteries that arise due to the inevitable slightly differing properties and characteristics of the component cells and batteries (Pryor, 2002).

3.7 DOMESTIC SOLAR HOT WATER SYSTEMS

A solar water heating system consists essentially of a "collector", which absorbs the solar radiation and heats the water and a means of circulating the heated water to the storage cylinder. This is achieved by natural convection (thermosyphonic action) or forced circulation by an electric pump. Available solar energy is absorbed by collectors and then transferred into the water, which is stored in an insulated tank until ready for use. An electrical or gas[30] heater is used for auxiliary heating to provide any balance heat required to maintain the hot water tank at the desired temperature. In some cases, additional primary heating devices such as wetbacks are also connected to the system (Clark, 1999). Fig. 3.17 illustrates a SHW system incorporating a wetback.

The overall performance (and hence the economics) of a solar water heating system at a given location is the resultant of the characteristic performance of the collectors, the area of collectors, the arrangement of the collectors (including inclination and orientation) and the arrangement of the system as a whole including such factors as the size of the storage cylinder in relation to the collector type and area. It depends also on the management regime of the system including factors such as thermostat temperature, water draw-off pattern and auxiliary heating pattern. For these reasons it is not easy to predict the performance of any given system in the field and the full testing of a system under standard conditions is a lengthy and expensive process (SIA, 2003).

Collector tests are described in detail in AS/NZS 2535:1999 and system tests are described in NZS 4613 1986.

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30. Form a grid connected distributed energy perspective, a domestic solar hot water (SHW) system could be thought of as an electrical load possessed by a customer with special characteristics, even when no electricity is required for the system at all (i.e. in the case of gas auxiliary heating). Such a view point would help a DG researcher to identify patterns of occurrence of auxiliary energy requirements and its relationship with variables such as hot water demand, solar isolation and so on (Fig. 7.16).

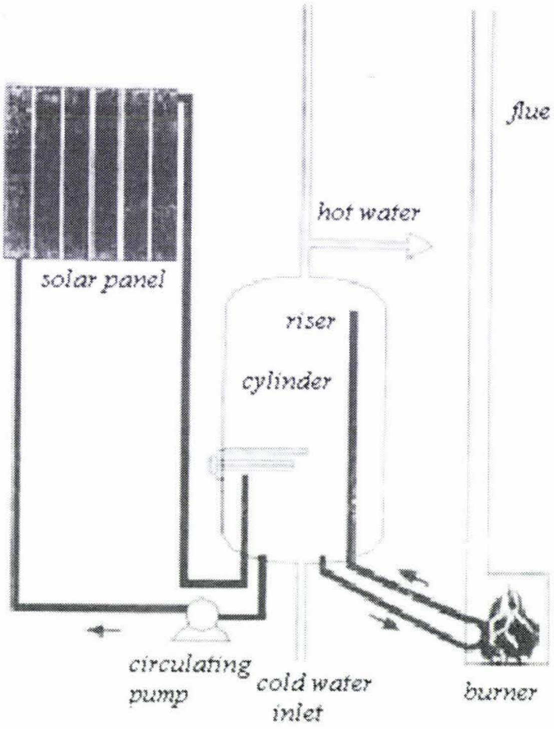

Fig. 3.17: A domestic solar hot water system incorporating a wetback.
(SIA, 2003)

A wide range of distributed energy technologies are currently available. Their selection depends on the initial costs as well as a range of other factors, as discussed in sections 8 and 9.

Note that the variables V and I in the equation; active power = $\frac{1}{T}\int_{0}^{T} VI\,dt$ (page 75)

are instantaneous values of voltage and current waveforms.

By expanding the right hand side of the above equation, it can be proved that active power = $V_{rms}*I_{rms}*\cos ø$

Where;

V_{rms} is the root mean square value of the voltage.
I_{rms} is the root mean square value of the current.
ø is the phase shift (as an angle) between the current and voltage waveforms.

(Note: Cos ø is defined as the power factor)

CHAPTER 04

Load Profiling and Synthesis of Load Data

This chapter describes how half hour time series load data (i.e. the daily load profile) of an individual customer, a group of homogenous customers or a large group of heterogenous customers could be synthesised from historical load data. Much of the methodology is based on load profiling techniques. Simple form load profiling concepts are covered in this chapter whose accuracy is deemed sufficient for this research.

In a deregulated market, electricity is a commodity that carries a time value (although for small customers the retailer absorbs the price fluctuations through agreeing on a fixed price, due to metering difficulties). The time value is dependent on which time of the day, month and the quantity of electricity delivered.

Half hour load data is a key input data that is necessary to simulate different dynamic distributed generation models for individuals as well as communities, under certain metering regimes.

4.1 'LOAD' AND THE TIME DOMAIN USED FOR AVERAGING

In alternating current (AC) both voltage and current oscillate in time, as determined by the frequency of the system. The instantaneous power flowing through a circuit is defined as the product of voltage (V) and the current (I). It can be proved that instantaneous power flow, over a certain time (say *T*), oscillates over a certain average value, which is termed as the active power.

Stated mathematically, active power = $\frac{1}{T}\int^{T} VI\,dt$

The term 'load' means the active power as defined in the above equation. The traditional method adopted by utilities for charging electricity consumed is on the basis of flow of active power[1]. The active power flow is a variable quantity in real time as electrical

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[1] *The amount of complexity of household electrical equipment has increased tremendously over the last few years. For example, electronic ballast lighting and computer monitors are non-linear loads that generate signal harmonics. Under non-linear loads summation of active power over sampling intervals (i.e. active energy) no longer represents the total energy delivered and hence the accuracy of billing using conventional methods is open to question (Moulin, 2002). As a response to improve billing, measurement of reactive power flow (which is the oscillating component of power flow, whose average is zero) is gaining interest. For example, Italy's leading energy distributor is in the process of replacing more than 20 million conventional household energy meters by new metering systems that meter the active power flow as well as the reactive power flow.*

equipment switch on and off due to user's personal choice (e.g. switching on an electric bulb by a customer, switching on of the customer's electric hot water system by a utility using ripple control) or automatic control (e.g. operation of a thermostat in a refrigerator).

The term 'load' is also used in a billing context to denote energy flow over a given time interval, which is the integral of active power over that time interval. As the energy flows are accounted for on a half hourly basis in New Zealand, both retailers and network operators, the pricing for electrical energy used in respect of any generic customer, for the purpose of mathematical modeling, can assumed to be based on measurements made over half hour intervals.[2] In the case of active power flows, half-hourly values could be either actuals metered through time of use (TOU) meters or in the case of the computer model described in section 6, estimated quantities on the basis of load profiling.[3]

4.2 LOAD PROFILING

4.2.1 Load Profiling Applications

Load profiling is defined as the process of taking the cumulative energy (kWh) usage of a customer over a billing cycle and assigning it to individual hours in the cycle, based on the aggregate characteristics of the customer segment in which the customer resides (Shepherd, 1997).[4]

Although the rationale for load profiling is to charge each market participant correctly for their usage,[5] as the market clearing price for energy in a competitive, open access environment changes from half hour to half hour, load profile data and the statistical techniques used for profiling can also be used for load forecasting as well.

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[2] *In respect of small customers who are not TOU metered, the assumption still holds good because the model algorithms can take care of the actual situation. See Appendix – M, section M.3.1 for algorithms pertaining to net metered customers.*

[3] *Under certain lines services pricing regimes based on certain peak periods (faced by a lines company), the amount charged to the customers would be based on actual times of occurrences of peaks and may not coincide with half-hour time intervals. Some simplifying assumptions were made for the computer model (section 6.2.1.4).*

[4] *This comprehensive definition is in agreement with MARIA's definition of load profiling, that is "load profiling is the estimation of a consumer's half-hourly consumption through the use of a 'profile' of that consumer's load shape" (M-co, 2003).*

[5] *If TOU metering could be economically implied (i.e. to install and administer) across all the customers, load profiling would be grossly redundant. However for residential customers, as mentioned in section 2.5.2, the costs are too prohibitive.*

Load forecasting has traditionally been used for distribution system planning. For the distrusted generation (DG) algorithms referred to in chapter 6, load-profiling techniques were used to synthesise the loads of an individual customer (section 6.2.2.1) as well as a wider community (Appendix N).

4.2.2 Load Profiling Methods

There are three load profiling methods documented in the literature of which only the first method is used in New Zealand.

- Static load profiling is based on historical load research data that are usually differentiated by season, month and day. These load profiles are used as a proxy for a customer's actual load shape. A major issue with this technique is its lack of a weather adjustment mechanism. Weather differences from the historical period to the current load profiling time frame are not considered. However weather is a significant determinant of a customer's demand and energy usage, and ultimately their load profile (Shepherd, 1997).

- Dynamic modelling makes use of historical load shapes but incorporates a weather response function into the profiling method (Shepherd, 1997).

- Dynamic load profiling requires that load research sample meters be read, data validated and load profiles produced daily for each customer segment. This approach is essentially a "real-time" construction of a customer segment's load shape. This technique captures all of the current factors that drive the shape of a load profile, but at a substantial increase in equipment and processing costs (Shepherd, 1997).

For this study, to meet the objective of synthesising a time series load data, the accuracy of static profiling is assumed to be adequate and the details pertaining to it are covered in section 4.2.3.

4.2.3 Static Load Profiling

The historical load research data required for static load profiling is derived through stratified sampling. In the stratification process, all customers who do not have TOU meters (i.e. the 'population' in statistical terms) are divided into a number of sub-groups (also known as customer classes) to the extent that each sub-group is homogenous as far as electrical energy use is concerned (e.g. customers with dairy milking sheds, residential customers with electrical hot water heating that is switched according to a given switching regime etc.).

In simple form load models, it is assumed that the shape of the load profile of any two customers of the same customer class is scaleable, that is the half hour load profile for every day of every year can be derived from a generic load profile for the customer class by rescaling it through an appropriate scale factor. The concept is illustrated in Fig. 4.1. The scale factor applied to customer B in Fig. 4.1 is twice as great as that applied to customer A.

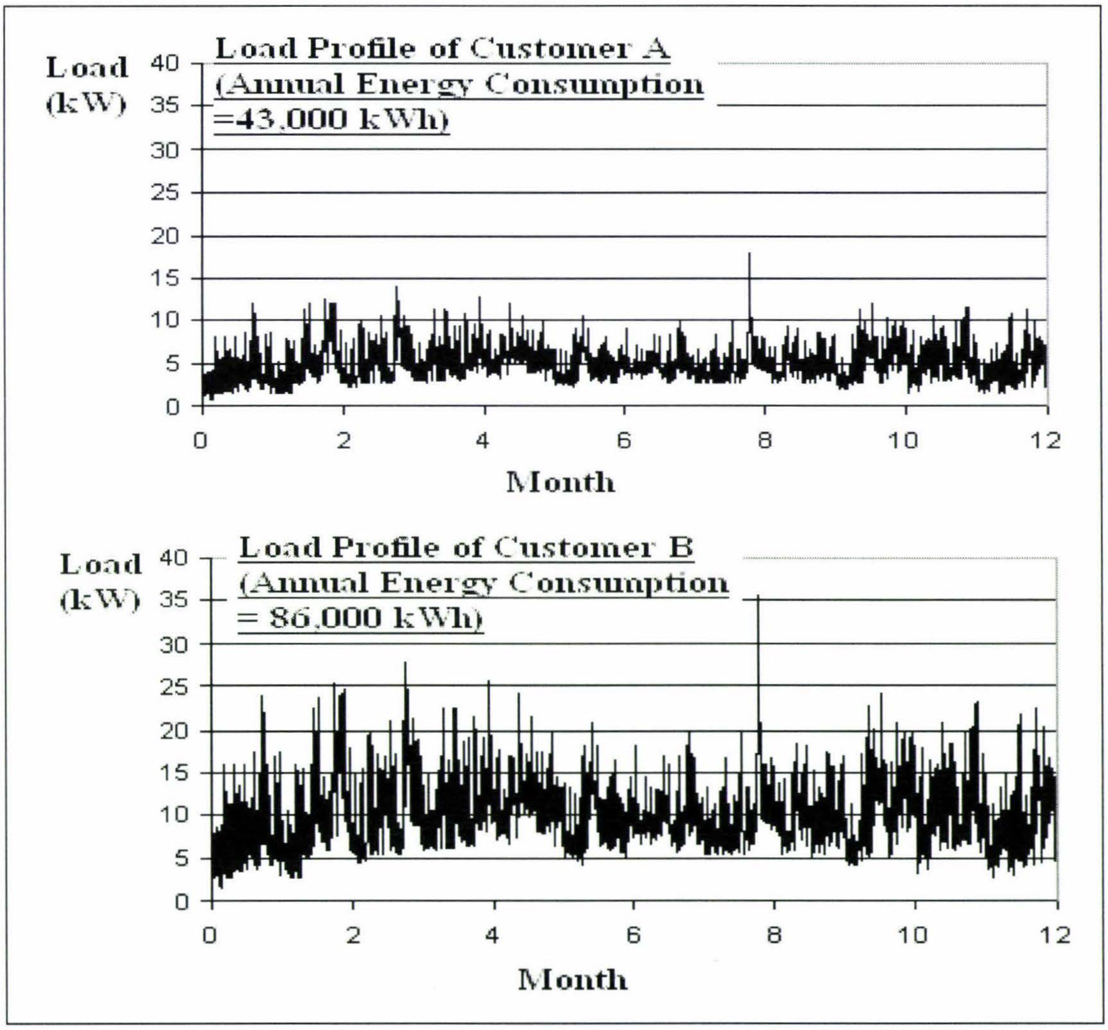

Fig. 4,1. Assumed shapes of load profiles of two customers of same customer class, under simple form load models[6,7]

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[6] *Half hourly load data may also be recorded in kWh, instead of (average) kW.*

[7] *The data required to plot the graphs were obtained from a real time load data logger referred to in section 5.8.1.*

Upon classification of the customer class, a sample is drawn at random for statistical analysis. The statistical analysis assumes that a customer's average half hourly load could be described by a random variable with mean $\overline{P}(t)$ and a standard deviation $S_p(t)$. In simple form load models, these parameters are expressed as linear functions of customer's annual energy consumption W_a as shown in Eq. 4.1 (Seppälä, 1996).[8]

$$\left.\begin{aligned} \overline{P}(t) &= L_c(m(t),d(t),h(t)) * W_a \\ S_p(t) &= S_{Lc}(m(t),d(t),h(t)) * W_a \end{aligned}\right\} \qquad \text{Eq. 4.1}$$

where $m(t),d(t),h(t)$ are classifying functions resulting in a category where a specific half hour t belongs. In general $m(t)$ is a month, but may be any other period depending on the accuracy required, $d(t)$ is day type (usually day of week or working day/holiday) and $h(t)$ is the half hour interval 1…48 for the day (Seppälä, 1996). The suffix 'c' denotes the class to which the customer belongs. Table 4.1 depicts how the $m(t),d(t),h(t)$ could be configured to obtain the desired accuracy required.

The parameters L_c and S_{Lc} are estimated from load research data of the customer class from the mean and standard deviation of the variable *half hour average kW load* of each customer (denoted $W_{h,c}(m,d,h)$ in Eq. 4.2) divided by the customer's *annual kWh energy consumption* (denoted $W_{a,c}$ in Eq. 4.2) for each customer in the customer class sampled (Seppälä, 1996). This is shown as a mathematical expression in equation 4.2.[9]

$$\left.\begin{aligned} L_c(m,d,h) &= E\left(\frac{W_{h,c}(m,d,h)}{W_{a,c}}\right) \quad \textit{for all customers in the customer class 'c'} \\ S_{Lc}(m,d,h) &= \sigma\left(\frac{W_{h,c}(m,d,h)}{W_{a,c}}\right) \quad \textit{for all customers in the customer class 'c'} \end{aligned}\right\} \quad \text{Eq. 4.2}$$

---

[8] *Once the shape of the probability density function is known, parameters, mean and standard deviation are sufficient to estimate the load of a given customer, for a given level of (statistical) confidence. For example, if a symmetrical bell shaped (Gaussian) probability density function is assumed (i.e. a normal distribution), it could be inferred that the load shall be* $(P(t) \pm 1.96\, S_p(t))$ *at 95% level of confidence. Gaussian distribution is the commonest probability distribution assumed in load research (Lehtonen, 1996).*

[9] Symbols E and σ *are the usual mathematical operators used in statistics to refer to the expected value (i.e. mean) and the standard deviation of a given variable. In this case the variable is* $W_{h,c}(m,d,h)/W_{a,c}$

The major drawback of the simple form load models is the sample bias when sample data is generalised to the whole customer class (i.e. the population). The bias occurs in generalisation because simple form load models do not consider the sample size (relative to the population) but an arbitrary variable, viz. the annual energy consumption[10] (Särndal, 1984).

Seppälä (1996) proposed two procedures to minimise the effect of sample bias. The first is for each energy retailer to undertake its own load research on the customers it serves and thereby narrow down the gap between the population and the sample size. This is already been implemented by New Zealand energy retailers. The other procedure is to reconcile the estimated community load profile (based on load research data) with the medium voltage (MV) feeder load profile (or a proxy such as the feeder current profile) at critical time intervals (i.e. peak times).

The above procedures were not used in this research because load data was obtained from a very small sample (N=3) which in any case is statistically not representative of a customer class (i.e. population) of any size.

Configuration of a model	**Application**
24 hourly values for 7 days a week for 12 months a year: $m = 1.....12,\ d = 1.....28(29)/30/31,\ h = 1.....48$	The is the most complete form, which is used mostly with pricing applications where the complete year's load data is needed. New applications for load forecasting and network load monitoring require this model. Specific for one year's calendar.
24 hourly values for 3 days (working day, Saturday and Sunday) for 12 months a year: $m = 1.....12,\ d = 1.....3,\ h = 1.....48$	Suitable for simple pricing applications. No specific calendar.
24 hourly values for 3 days (working day, Saturday and Sunday) for 26 two-week periods of the year: $m = 1.....26,\ d = 1.....3,\ h = 1.....48$	Traditionally used in long term production planning applications and also network planning and load flow applications. No specific calendar

Table 4.1: Different configurations of load models and their applications (Seppälä, 1996)

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[10] *The rescaling/generalisation can also be done through any other interval in the billing cycle such as monthly energy consumption. However it is preferred to use annual energy consumption in this study, as it is used in line company product pricing strategies.*

4.3 ESTIMATING THE REAL TIME LOAD OF ANY ONE SINGLE CLASS OF CUSTOMERS

Let $\overline{P}_{i,j}(t)$ and $S_{p\ i,j}(t)$ denote the mean and standard deviation of the i^th^ customer of the j^th^ customer class (j = 1, 2, …., n). Let X_i denote the number of customers under each customer class (i = 1, 2 …., n) and $Wa_{,i,j}$ denote the annual energy consumption of the i^th^ customer of the j^th^ customer class (j = 1, 2, …., n).

Now, according to Eq. 4.1, the mean load of the i^th^ customer of the first customer class is $L_1(m(t),d(t),h(t)) * Wa_{,i,1}$, while the standard deviation of the i^th^ customer is $S_{Lc}(m(t),d(t),h(t)) * Wa_{,i,1}$.

Since in statistics, the mean of the sum of any number of independent random variables is equal to the sum of the means of each random variable, assuming that the load of one customer in a given customer class is independent of the other customer of the same customer class, using Eq. 4.1, the mean load of the first customer class $P_1(t)$ is given by:

$$\overline{P_1(t)} = \sum_{i=1}^{i=X1} L_1(m(t),d(t),h(t)) * Wa_{,i,1} / X_1 = [L_1(m(t),d(t),h(t))] / X_1 * \sum_{i=1}^{i=X1} Wa_{,i,1} \quad \text{Eq. 4.3}$$

Eq. 4.3 is a very useful simple formula that could be used to estimate the mean value of the load of any customer class at any given half hourly interval. All one needs is the total annual energy consumption of that customer class and the load research data that is representative of that customer class.

Since, the square of the standard deviation (i.e. the variance) of the sum of any number of independent random variables is equal to the sum of the squares of the standard deviations (variances) of each random variable, assuming that the load of one customer in a given customer class is independent of the other customer of the same customer class, the standard deviation of the load of the first customer class $\sigma(P_1(t))$ is given by:

$$\sigma^{2}(P_{1}(t)) = \sum_{i=1}^{i=X1} (S_{L1}(m(t),d(t),h(t)) * Wa_{,i,1})^{2} \qquad \text{Eq. 4.4}$$

$$\text{Hence } \sigma(P_{1}(t)) = S_{L1}(m(t),d(t),h(t)) * \sqrt{\sum_{i=1}^{i=X1} (Wa_{,i,1})^{2}} \qquad \text{Eq. 4.5}$$

One limitation in using Eq. 4.5 is that the estimator needs to know the annual energy consumption of each of the customers in the class. The aggregate annual energy consumption of the customer class is not sufficient to compute the standard deviation of the customer class. To circumvent this difficulty, the following procedure is proposed.

It is assumed that the standard deviation of the load of one customer in the customer class is approximately identical to the standard deviation of any other customer in the same customer class, and can be expressed as a common variable $\sigma_{one\ customer}$.

Based on the above assumption; $\sigma_{one\ customer} = \sum_{i=1}^{i=X1} (S_{L1}(m(t),d(t),h(t)) * Wa_{,i,1}) / X_{1}$

Also, $\sigma^{2}(P_{1}(t)) = X_{1} * \sigma^{2}_{one\ customer}$.

$$\text{Hence, } \sigma^{2}(P_{1}(t)) = X_{1} * \Big(\sum_{i=1}^{i=X1} (S_{L1}(m(t),d(t),h(t)) * Wa_{,i,1}) / X_{1}\Big)^{2}$$

$$= (1/X_{1}) * \Big(\sum_{i=1}^{i=X1} (S_{L1}(m(t),d(t),h(t)) * Wa_{,i,1}\Big)^{2}$$

$$\text{Thus, } \sigma(P_{1}(t)) = S_{L1}(m(t),d(t),h(t)) * (1/\sqrt{X_{1}}) * \sum_{i=1}^{i=X1} Wa_{,i,1} \qquad \text{Eq. 4.6}$$

Eq. 4.6 is more amenable compared to Eq. 4.5 in that all the estimator needs (apart from the standard deviation scaling factor $S_{L1}(m(t),d(t),h(t))$ derived from load research) is the aggregate annual energy consumption of the customer class and the number of customers.

Also consider the coefficient of load variation of the customer class; $\overline{P_1(t)} / \sigma(P_1(t))$.

From Eq. 4.3 and Eq. 4.6;

$$\overline{P_1(t)} / \sigma(P_1(t)) = L_1(m(t),d(t),h(t)) * \sum_{i=1}^{i=X1} Wa_{,i,1} / S_{L1}(m(t),d(t),h(t)) * (1/\sqrt{X_1}) * \sum_{i=1}^{i=X1} Wa_{,i,1}$$

Hence, $\overline{P_1(t)} / \sigma(P_1(t)) = (L_1(m(t),d(t),h(t)) / S_{L1}(m(t),d(t),h(t))) * (1/\sqrt{X_1})$ Eq. 4.7

Eq. 4.7 suggests that the coefficient of load variation of the customer class is inversely proportional to the square root of the number of customers in a customer class. Accordingly, it follows that if it is possible to group a larger number of customers to a customer class, the resulting load profile would be more definitive as opposed to the resulting load profile of a smaller group of customers.

4.4 ESTIMATING THE REAL TIME LOAD OF A COMMUNITY

In a broad sense, the real time load of a community (i.e. the average load on a MV feeder, every half hour, could be thought of as the summation of real time residential electrical loads and commercial electrical loads. Commercial electrical loads are the loads that are to do with the economic activity of the businesses and non-residential buildings within the community.

Development of a community load profile that consists of n types (classes) of customers is explained here. However, it is believed that some form of homogeneity exists in a New Zealand rural community and hence all the customers[11] could be assigned to either one of two residential classes (a main house such as a fully equipped farmhouse or a cottage) or one of two or three industrial/commercial classes (Fig. 4.2).

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[11] *In a strict sense, "customers" can considred to be installation control points (ICPs) because lines companies and energy retailers consider each ICP as a separate customer, each is identified with a separate electricity account.*

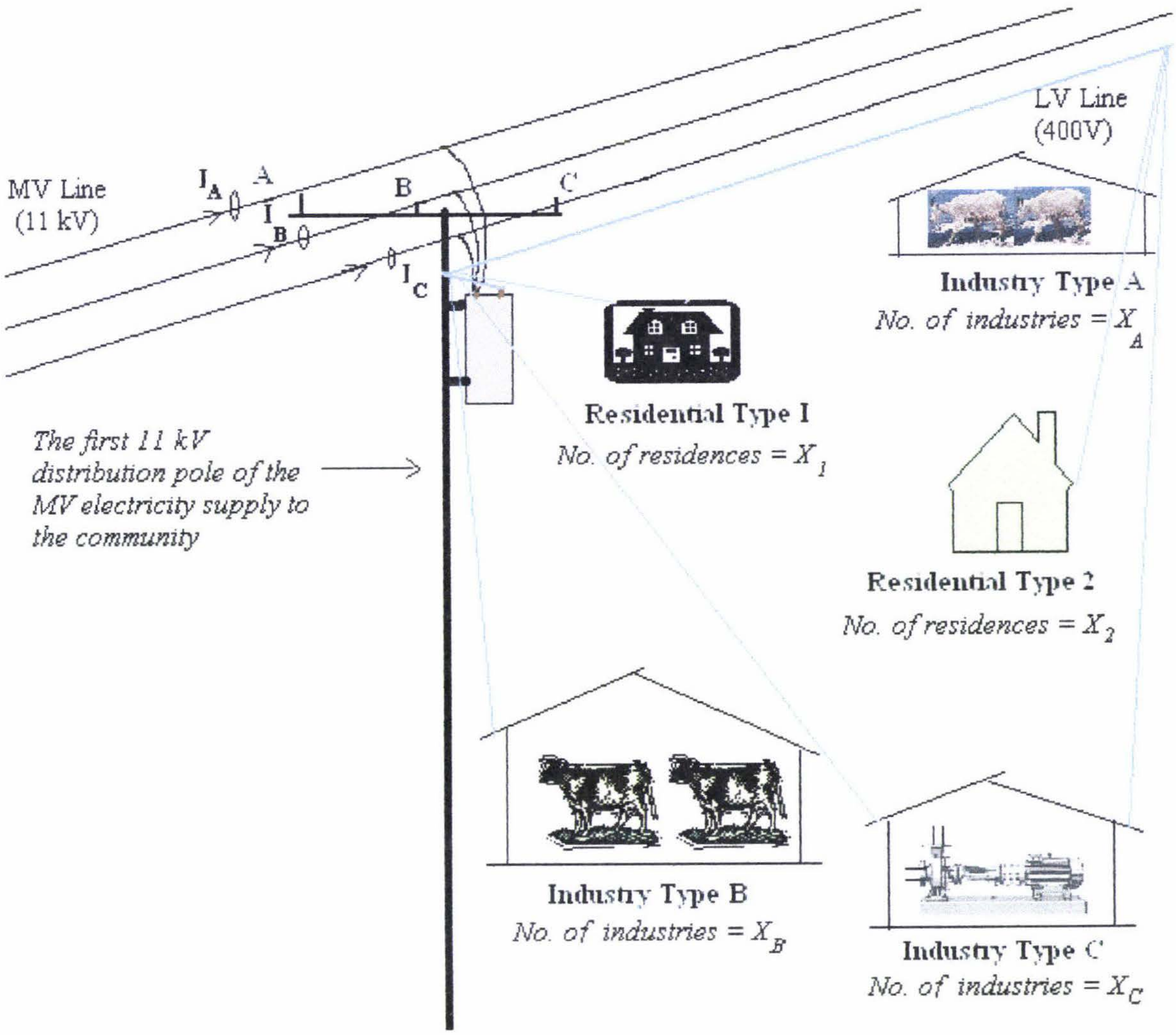

Fig. 4.2: A rural community consisting of two residential types and three industrial types

Assuming that the load of one customer class is independent from the other customer classes, the mean $\overline{P}$ and standard deviation σ of the community load at any half hour time interval (t) of a given day (d) of month (m) of a year are given by:

$$\overline{P} = L_1(m(t),d(t),h(t)) * \sum_{i.=1}^{i=X1} (Wa)_{i,1} + L_2(m(t),d(t),h(t)) * \sum_{i.=1}^{i=X2} (Wa)_{i,2} + \ldots\ldots\ldots\ldots$$

$$+L_n(m(t),d(t),h(t)) * \sum_{i.=1}^{i=Xn} (Wa)_{i,n} \qquad \text{Eq. 4.8}$$

and $$\sigma'^2 = \left(S_{L1}(m(t),d(t),h(t)) * (1/\sqrt{X_1}) * \sum_{i.=1}^{i=X1} (Wa)_{i,1}\right)^2 + \left(S_{L1}(m(t),d(t),h(t)) * (1/\sqrt{X_2}) * \sum_{i.=1}^{i=X2} (Wa)_{i,2}\right)^2 + \ldots.. + \left(S_{L1}(m(t),d(t),h(t)) * (1/\sqrt{X_n}) * \sum_{i.=1}^{i=Xn} (Wa)_{i,2}\right)^2 \qquad \text{Eq. 4.9}$$

Table 4.2 assembles Eq. 4.8 and Eq. 4.9 to form the algorithm for the estimation of real time community load.

Obviously the estimated mean real time load of the community (= sum [row1 to row n] in Table 4.2) is expected to be significantly different from the measured real time load of the distribution feeder. One method suggested by load researchers to improve the accuracy of a statistical parameter based on a simple load model to obtain feeder load data over any critical half-hour interval[12] is to apportion the difference between the estimated mean real time load of the community and the measured real time load in proportion to the standard deviations of the respective customer classes (Seppälä, 1996).

4.5 Available data sources for estimating the real time load of a community

Obviously the most accurate way of estimating the real time load of a community by a DG researcher is to collect time series load data from all the customers of the community. Since this is cost prohibitive in most cases, it is often necessary to draw a sampling frame and obtain data from a statistically valid sample. Alternatively researchers can have recourse to historical sample data available with the utilities and other research enterprises in respect of different customer categories. For example there are a range of MARIA

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[12] *In most New Zealand substations the distribution feeders are now equipped with SCADA systems and hence accurate real time load data for the whole feeder is readily available. However measurement of feeder load downstream of a substation is a costly process and involves such hardware as voltage and current transducers, data loggers and so on. In a well laid system (i.e. a reasonably balanced system) actual load could be estimated from the three phase currents assuming a known power factor and a system voltage. Based on discussions with the lines companies, for a rural NZ MV feeder, an assumption of a power factor of 0.9 and a system voltage of 11.5 kV would be good values. The load could be estimated by the formula for active power in a 3-phase 3-wire system.*

Hence load $= \sqrt{3}\ VI^*$ *power factor* $= \sqrt{3} * 11.5*(I_A + I_B + I_C)/3* 0.9$. *The measurement of the three phase currents is relatively less costly and could be accomplished by clip-on type current meters.*

approved load profiles developed by energy retailers for different domestic as well as some industrial categories (e.g. dairy milking sheds). These are not public information and M-co, who administers MARIA, is not obliged to release such data or load shapes. They should be obtainable from energy retailers at their discretion.

Customer Class or Row No.	**Load Research Data (Eq. 4.2)**		**Estimated Load Profile Parameters of the Customer Class**	
	Mean load ÷ kWh	**Standard deviation ÷ kWh**	**Mean load (kW)**	**Standard deviation (kW)**
1	$L_1(m(t),d(t),h(t))$	$S_{L1}(m(t),d(t),h(t))$	$L_1(m(t),d(t),h(t)) * \sum_{i.=1}^{i=X1} (Wa)_{i,1}$	$S_{L1}(m(t),d(t),h(t)) * (1/\sqrt{X_1}) * \sum_{i.=1}^{i=X1} (Wa)_{i,1}$
2	$L_2(m(t),d(t),h(t))$	$S_{L2}(m(t),d(t),h(t))$	$L_2(m(t),d(t),h(t)) * \sum_{i.=1}^{i=X2} (Wa)_{i,2}$	$S_{L2}(m(t),d(t),h(t)) * (1/\sqrt{X_2}) * \sum_{i.=1}^{i=X2} (Wa)_{i,2}$
⋮	⋮	⋮	⋮	⋮
n	$L_n(m(t),d(t),h(t))$	$S_{Ln}(m(t),d(t),h(t))$	$L_n(m(t),d(t),h(t)) * \sum_{i.=1}^{i=Xn} (Wa)_{i,n}$	$S_{Ln}(m(t),d(t),h(t)) * (1/\sqrt{X_n}) * \sum_{i.=1}^{i=Xn} (Wa)_{i,n}$
Total Community ⇒			= Sum [row1 to row n]	=Sqrt [Sum{square of row1 to square of row n}]

Table 4.2: The algorithm for the estimation of real time community load

As regards load data on households, the most comprehensive data base belongs to the Building Research Association of New Zealand (BRANZ). The household energy end-use project (HEEP) is a project developed and run by BRANZ. The data has been collected from sample households from clearly identified sampling frames for several regions of the country and hence can consider being representative of the national households.

For example, the results on load profiles based on time series load data collected from a sample of 29 houses in the Wanganui region over a period of five months from April 1996 onwards is published in HEEP year 2 report released in June1998 (EECA, 1998). The report classifies 144 load profiles based on average time of the day (based on 48 half hourly intervals) monthly profiles for each house (i.e. 144 Ω 5 times 29) into 6 classes by automatic identification of representative patterns using artificial neural networks. Figs. 4.3 through 4.8 depict the representative load profiles of each class along with best fit lines (mean) and variability (standard deviation). The shapes of the load profiles of the six classes are described as follows (EECA, 1998):

Class 1: Low flat morning peak, high late afternoon peak.

Class 2: Sharp, high morning peak, medium afternoon and evening consumption.

Class 3: Sharp, early morning peak, low afternoon consumption, high evening peak.

Class4: Highest peak during night rate period, flat low day consumption, medium evening peak (i.e. a night rate profile).

Class 5: High, flat morning peak, high afternoon consumption, small, early evening peak.

Class 6: Shallow, flat morning peak, high afternoon consumption, early night peak.

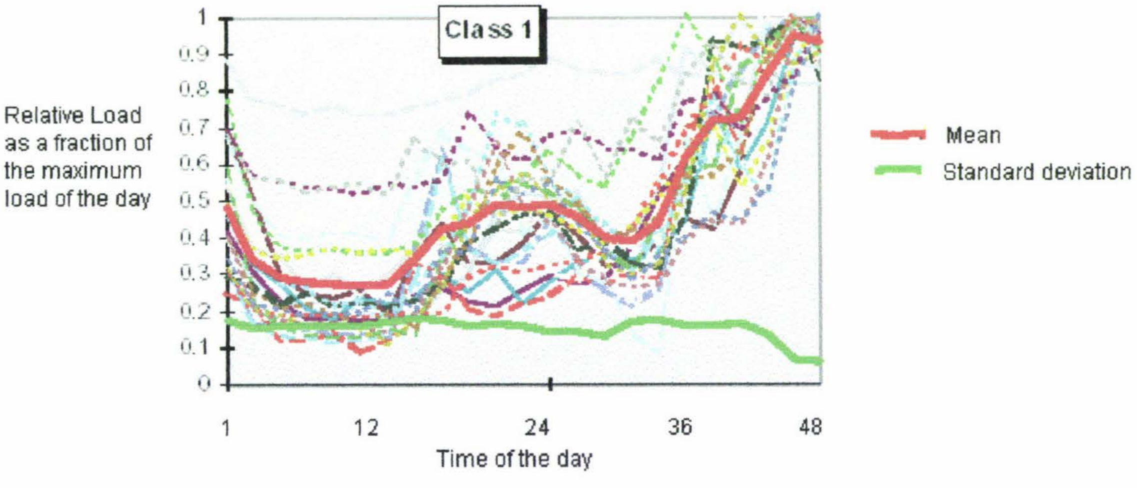

Fig. 4.3: The load profile of 'Class 1' load shape category

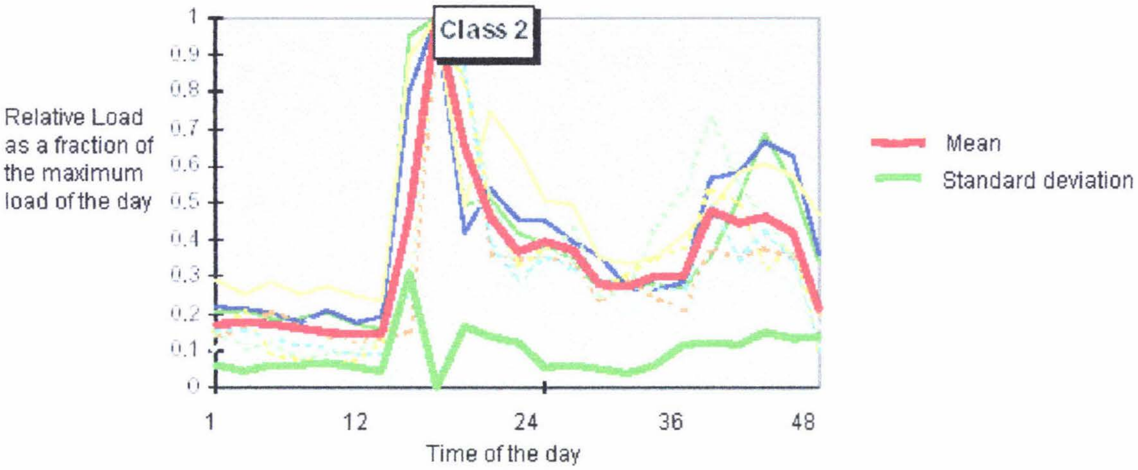

Fig. 4.4: The load profile of 'Class 2' load shape category

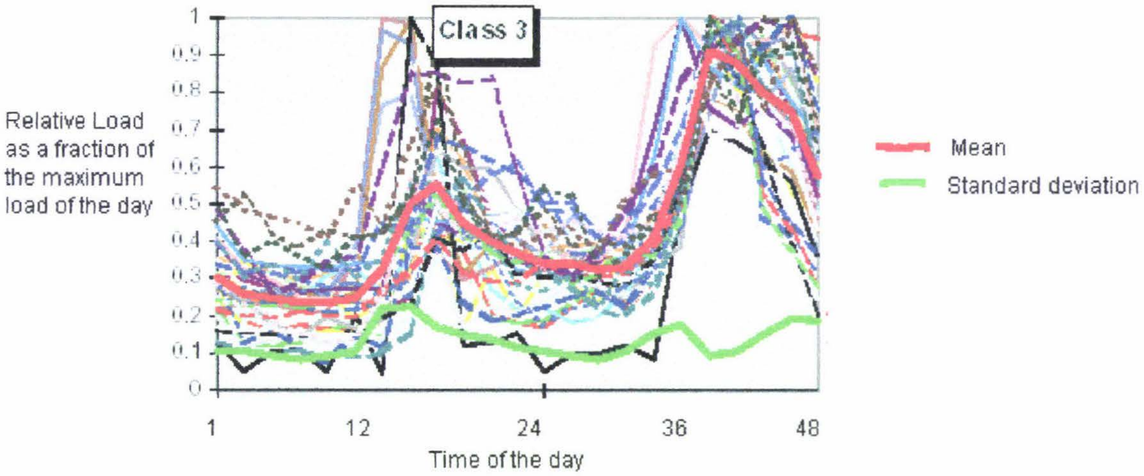

Fig. 4.5: The load profile of 'Class 3' load shape category

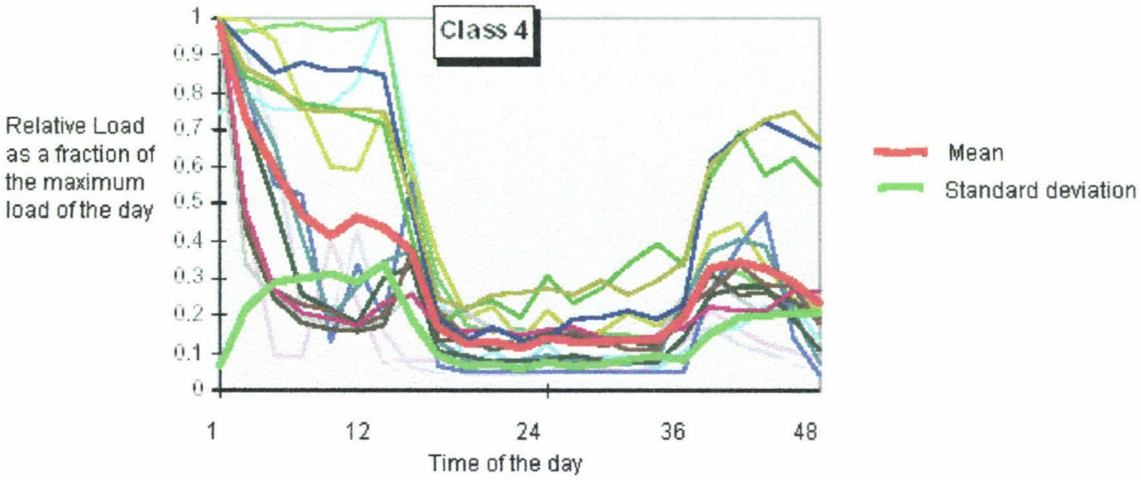

Fig. 4.6: The load profile of 'Class 4' load shape category

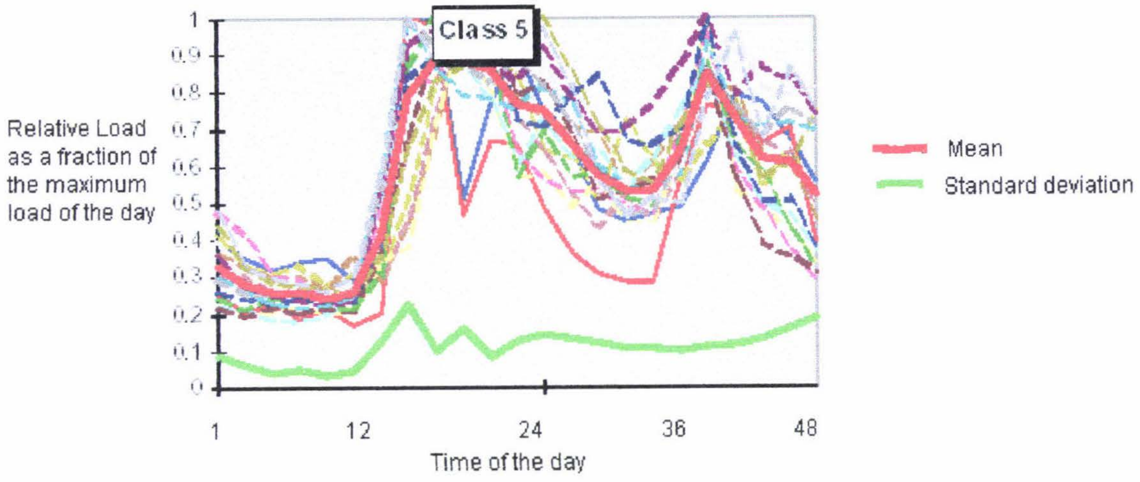

Fig. 4.7: The load profile of 'Class 5' load shape category

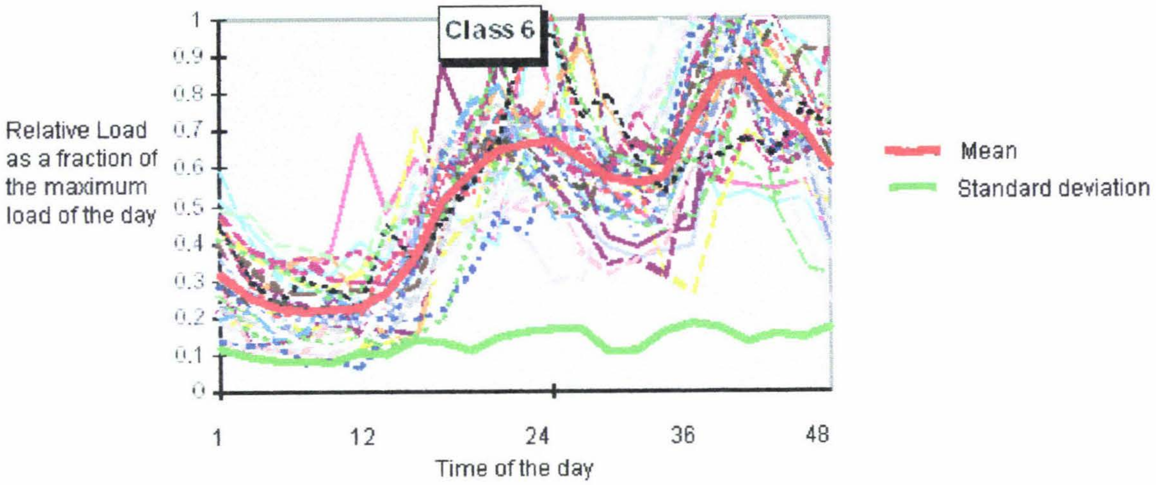

Fig. 4.8: The load profile of 'Class 6' load shape category

4.6 LOAD RESEARCH ON RURAL AGRICULTURAL COMMUNITIES AND THE IMPACT OF NEW TECHNOLOGY ON LOAD PROFILES

According to the 2001 national census report, only about 1 in 3 rural New Zealand adults were engaged in agriculture or fishery related employment.[13] This suggests that the electrical energy use studies related to economic activity of rural New Zealand should be explored beyond agricultural activities. However, understanding the published research on electrical energy end use patterns on New Zealand' s major rural agricultural activities, viz. dairy cattle farming, beef cattle farming and sheep farming, provides a useful insight on the shape of load curves and demand side operational strategies.

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[13] *However, this proportion is still relatively significant when compared to the urban scenario, where only 1 in 26 was in agriculture or fishery related employment (section 7.2.2).*

To date there has been no published data on any nation-wide electrical energy use study on New Zealand's beef and sheep farming activities (i.e. a study similar to HEEP). Based on load research involving large Canadian national samples, it was concluded that running electrical load in beef cattle and sheep farms is marginal (Clarke, 2003). In almost all the cases, over 90% of the load consisted of residential loads (i.e. loads of the main farmhouse and the cottages).[14] These results conform with New Zealand research on small samples, with the exception of the short periods during which shearing activity take place on a sheep farm (Irving, 2000 and Murray 2002).

Dairy farming on the other hand is an electrical energy intensive farming operation all year round. It is estimated that an average New Zealand dairy farm uses from 15,000 to 25,000 kWh of electricity for hot water alone for cleaning in place (CIP) operations. Considering a milking frequency of 220 days plus a hot water (electricity) demand of 20,000 kWh per annum, hot water alone amounts to an average electrical load of 3.8 kW during the milking season (EECA, 1996). In addition to CIP operations, electricity is also used to operate milking machines, vacuum pumps, milk refrigeration and in some cases for pasture irrigation, feeding and manure handling.

The load profiles of dairies can significantly be improved as a result of peak shaving by staging the activities (by sequencing the operation of loads) and using energy efficient new technology. At present CIP waste heat recycling systems are being tried and there exists scope in the future for new CHP technology involving small diesel engines for generation of hot water for CIP operations and refrigeration (operating on vapour absorption refrigeration cycles).[15]

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[14] *The researchers (Clarke et al, 2003) recommend that because domestic loads command proportionately high energy demand, energy efficiency strategies should be aimed at household energy use. One new technology introduced in this regard is energy efficient soft start submersible water pumps for domestic and stock water supplies. Use of historical load data will become less accurate when new technological interventions such as the application of energy efficient water pumps become dominant.*

[15] *Based on data published by reputed manufacturers, 30 kW_e seems to be the lower limit for commercial CHP applications involving reciprocating engines. This capacity is a little high for CIP and refrigeration applications on an average dairy.*

CHAPTER 5

Research Design

This chapter describes how the instrumentation was designed and installed to collect the data necessary to propose solutions to the issues at hand.

5.1 RESEARCH DESIGN CONSIDERATIONS

In designing the research method the first priority was to look at a way of obtaining data and information from a clearly defined focus group though which research objectives could be achieved within the timeframe and budget constraints.

5.2 SAMPLE SELECTION

Selecting a statistically representative sample to represent rural New Zealand was considered impractical within the constraints. Stratifying rural communities on account of their diversities (e.g. in size, occupation, geography, type of fuel used to meet energy requirements etc.) would be difficult and a time consuming task. These diversities have different demand side implications on the resulting load profiles. The community load profiles do largely influence line companies in formulating their product and pricing strategies. This in turn has a direct impact on the contingent optimum distributed generation (DG) strategy, from the point of view of the entrepreneur.

The study therefore concentrated on selecting a small rural community and hence a convenience sample. Massey University, in collaboration with the crown research institute Industrial Research Limited, Christchurch had been monitoring data in a remote rural community in Totara Valley, down Kumeroa Woodville for over 2 years. Therefore it was assessed whether Totara Valley could also be chosen as the case study sample for this research. A major requirement to qualify as a suitable case study sample was to test whether the community would become a possible candidate for discontinuation of supply in year 2013 on account of the provisions of the Electricity Act 1992, on economic viability of supplying electricity by a lines company.

The ODV report (valuation as on 31 March 2001) of the Danneverke based lines company Scanpower Limited which supplies lines services to Totara Valley, was reviewed with a view to ascertain whether any information could be obtained on the economic viability of

Scanpower's network assets (i.e. the distribution lines and its associated assets such as transformers) allocated to Totara Valley. According to Scanpower's ODV report, all its feeders are economically viable in that optimum depreciated replacement cost (ODRC) is very much lower than its corresponding economic value (EV). This means the 11 kV feeder named "country feeder" that originates from Woodville substation and terminates at Totara Valley (as a spur line), is economically viable for ScanPower when it considers all its customers connected to that feeder and its spur lines. This feeder feeds electricity to some 115 domestic customers and 401 commercial customers[1], mainly farmers.

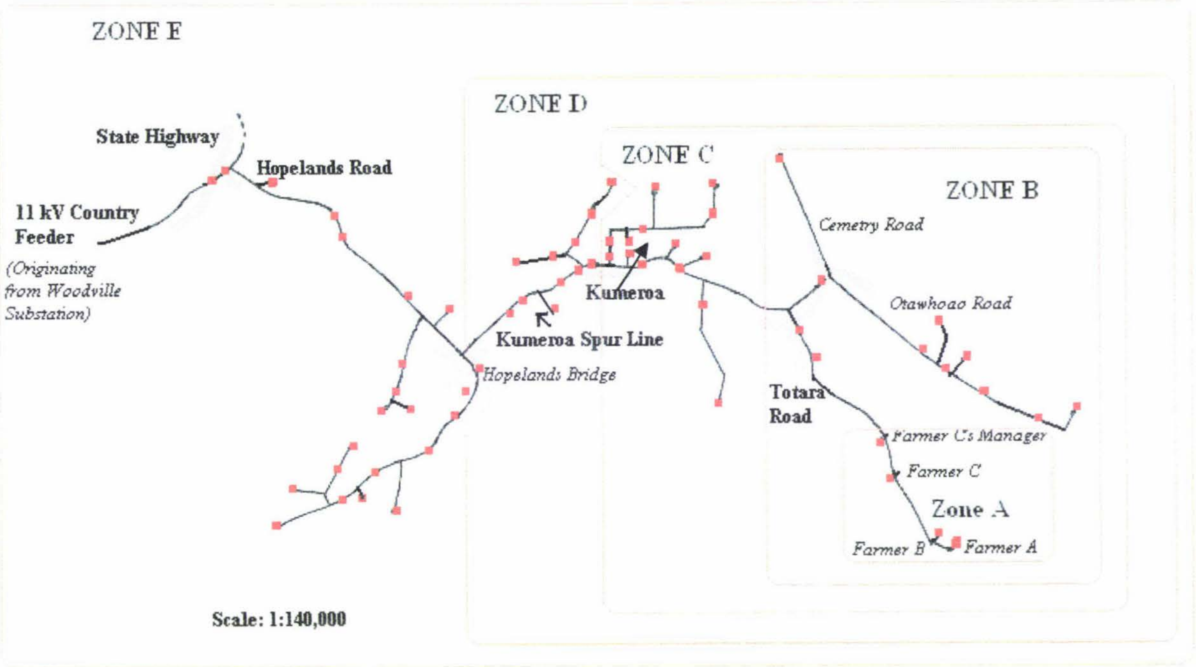

Fig. 5.1: The 11 kV Electricity Distribution Configuration for Kumeroa and Hopelands areas[2]

According to the data published in ScanPower's ODV report, at a more de segregated spur line level, five spur lines trigger the application of the government guideline (stipulated in MED's ODV Handbook) for testing for possible existence of uneconomic distribution sections (section 2.5.3.1). The spur line named "Kumeroa" belonging to the 11 kV feeder known as the "country feeder" (Fig. 5.1) which reticulates electricity to

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1. *As in the previous chapter, the term 'customer' means any installation control point (ICP) since lines companies and energy retailers refer to each ICP (and its corresponding electricity account) as an individual customer. The actual number of individuals under whose names the ICPs are established is much lesser.*

2. *The figure was adapted from ScanPower's System Diagram for the Woodville GXP. The red dots refer to load concentration points, identified by the 11kV/400V distribution transformers. The sections of the other feeding areas of the 11 kV country feeder are not shown.*

Totara Valley area, was one of the five spur lines that trigger the above requirement, on account of having a low kVA/customer ratio of 8.1:1. Based on this information it was decided that Totara Valley would be a good case study sample.

Apart from the above geographic factor, there were other factors that influenced the choice of Totara Valley as the case study sample. These were the excellent rapport between the case study community and the researchers (Massey /IRL), excellent working relationship between ScanPower and Massey /IRL and the state of research progress that had already been made on Totara Valley at the time of initiating this aspect of the research.

5.3 DESCRIPTION OF THE CASE STUDY COMMUNITY

The case study is centred on three North Island Hill Country farming families[3] living in the Totara Valley, which is situated 24km to the east of Woodville behind the Kumeroa township. It is accessed from State Highway 2 through Hopelands Road (5 km east of Woodville). Sheep and beef farming was the principal economic activity of all three farming families[4]. The topography of the valley and the demarcation of the three farms and the buildings/ICPs are shown in Fig. 5.2.

The head of the valley consists of the largest farm with an area of 971 ha (i.e. Farm A depicted in Fig. 5.2). The neighbouring farms B and C had an area of 640 ha and 600 ha respectively. All three farms can be considered as large farms when compared with the national average of 400 ha for a north island hill country sheep and beef farm. The sheep shearing frequency adopted by the farmers was twice a year. In two of the farms there was at least one cottage in addition to the farmhouse. In the other, there were three cottages (in addition to the farmhouse) of which one remained unoccupied for some time.

On inspection of the electricity bills, it was evident that, as expected, the residential loads were dominant. Fig 5.3 depicts the bi-monthly electricity consumption of the farmhouse, the woolshed and the freezer shed of Farm A based on the electricity bills

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3. *One farming family employs a full time farm manager who lives in the farm with his family in a separate cottage. Thus in a strict sense, as far as load research is concerned, the study covered the electricity use of that family as well.*

4. *For ease of reference, the report will herein after sometimes use Farm A, Farm B and Farm C to refer to each farming family in the farms A, B and C respectively.*

received from July 2001 through June 2002. The electricity consumption of the cottages was in the range of 20-30% of the farm house for each period. The electricity consumption patterns of the other two farmers were somewhat similar, with the notable exceptions being lesser energy consumption at the woolsheds of Farms B and C and a lower freezer load at the freezer shed of Farm B.

Apart from residential and shearing loads, all three farms have freezer loads on account of having separate freezer sheds. However freezing of meat is not so much an integral part of the economic activity of the farmers and the meat was used primarily for domestic consumption and to feed the farm dogs. Therefore, as expected, the energy consumption

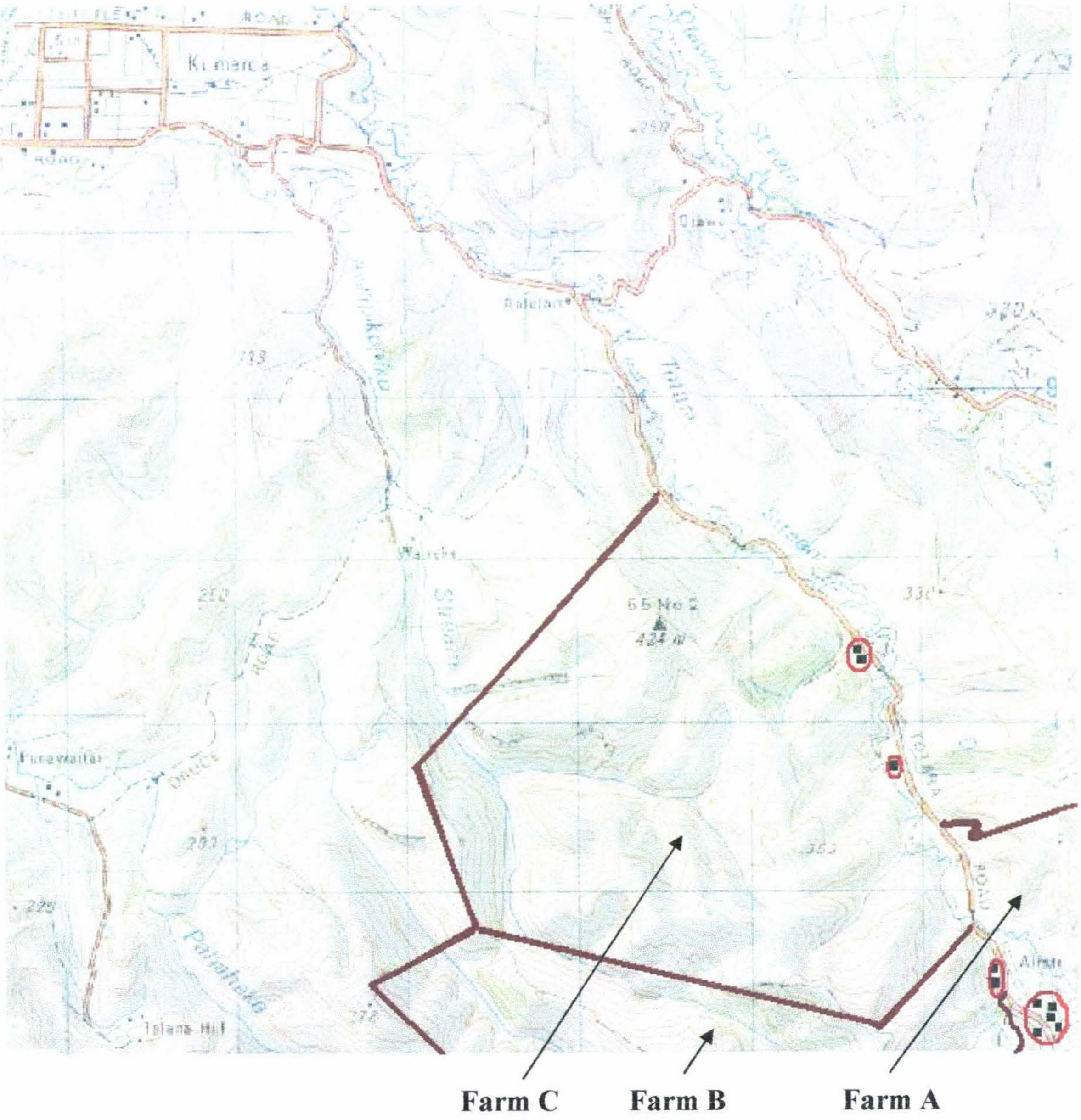

Fig. 5.2: The topography of Totara Valley and the demarcation of the farms and buildings

at the freezer sheds remained low and steady with seasonal variations apparently due to the ambient temperature.

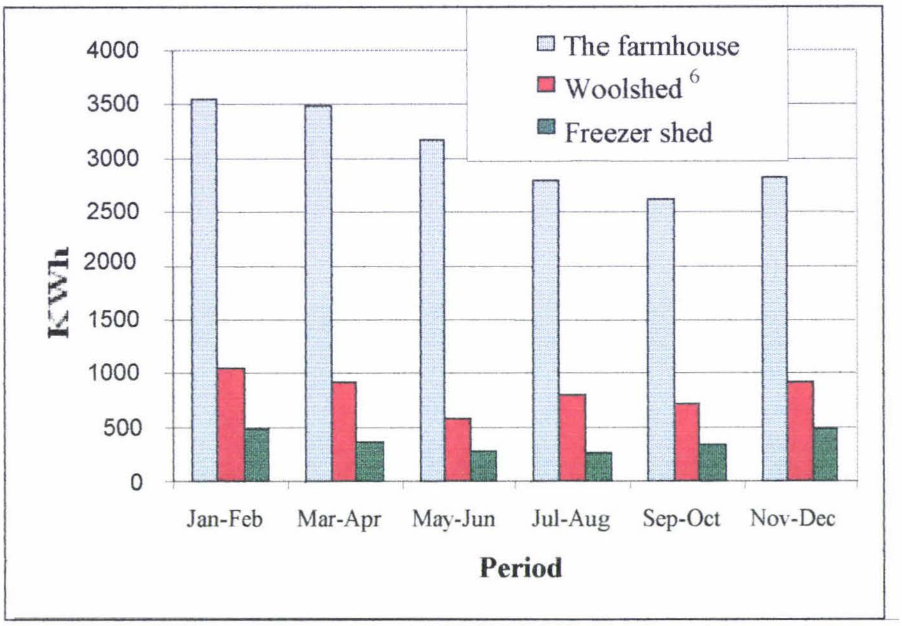

Fig. 5.3: Bi-monthly[5] energy consumption of key loads at Farm A, based on electricity bills received from July 2001 trough July 2002

Based on published data (Irving, 2000), there is good micro hydro and wind power potential in the community. The micro hydro potential is attributable to the Totara stream, (which is a tributary of the Manawatu river) running along the valley.

5.4 PREVIOUS PROGRESS

There had been load data collection from all the major ICPs in the community since 1999. In installations having old wiring, it was the current data that had been logged (as a proxy to kWh) using clip on type current transducers without disturbing the wiring while in other installations kWh data have been logged by hardwiring to the kWh dataloggers.

Apart from load data, the previous Massey researchers (Murray and Irving) have also collected wind speed data (at different locations) and water inflow data for research purposes. Murray, among other things, is analysing the wind potential using advanced modeling techniques.

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5. *The reason for grouping two months together is because the actual meter readings are taken only once every two months. To present an accurate reflection of energy consumption, only the actual meter reading differences occurring every other month were considered and not the estimated accounts.*

6. *Please note that the energy consumption of the whooshed includes the load of the power fence (50J stored energy) and outdoor flood lighting. These loads are independent of shearing loads.*

As a part of the technology demonstration process to the community, action had been taken to install three 100Wp ac PV modules (one each per farmer's main house), a solar hot water system for farmer A and a heat pump for Farmer B. Implementation of all the above mentioned distributed energy systems took place shortly after this study began.

5.5 TECHNOLOGICAL AND ECONOMIC CONSIDERATIONS

5.5.1 Setting objective criteria for utilisation of distributed generation systems

Since there are several DG technologies that can be combined into literally infinite number of permutations and combinations of capacities (sizes) and technologies and modes of operations, the first step taken in the research design was to establish practically viable objective criteria for adaptation of DG systems. Three important criteria were identified and accommodated.

- Electricity is a commodity that carries a time value of money. The price at any given time will reflect the underling status of producing and delivering electricity to the customer's location, although due to the present high costs of TOU metering it is prohibitive for small customers.[7] It was hypothesised that dispatching a given quantity of generation at the right time is more beneficial to both parties, the "right time" being those times of the day when the price of electricity delivered is expected to be high. See section 8.4 to ascertain whether this hypothesis can be accepted.

- There are different TOU metering systems with each metering system reflecting the utility's philosophy on DG. One therefore needs to be realistic about possible metering scenarios (section 2.6.3 and Appendix - D).

- Economies of scale benefits can be derived if it is possible to accommodate DG at a larger scale (section 2.4 and Fig. 2.2). Therefore one needs to look into ways of accommodating larger DG units at a community level, bearing in mind the fact that from a DG investor's viewpoint, the key economic objective of owning a DG system would be the realisation of a satisfactory return on investment.

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[7] *Any metering that does not involve TOU for DG injected will contain an element of uncertainty that will be reflected in the price that is negotiated between a utility and a customer. Although a contract, in legal terms is assumed to be negotiated between two parties of equal bargaining strength, in reality it never materialises when a utility negotiates a contract with a small customer on an individual basis. A small customer will always be at a disadvantage, in terms of prices agreed upon.*

The tariff impact on utilisation of a larger DG unit was further analysed using two distinct buy and sell tariffs for each half hour each day on the presumption that there exists a metering arrangement that captures gross import and gross export load profiles through a dual-element electronic meter (see metering scheme 2b in Appendix - D)[8]. The sell tariff refers to rates that are applicable to any export of kWh energy to the grid, which is assumed to be the avoided cost of energy for the retailer (buyer) who would otherwise have to buy energy from the wholesale spot market.

The analysis is shown below and Fig. 5.4 illustrates the metering arrangement. In this instance, it was assumed that the DG investor receives revenue (or avoids costs) only on energy generation and not on capacity provision (i.e. no incentive for capacity support from the lines company). It should be noted that this assumption cannot be made to all the rural cases in NZ. For example a rural DG system owner connected to the Orion network in the Canterbury region can receive additional revenue for capacity support during the peak summer periods due to network loading because of the operation of irrigation pumps.

Let $L_{DG,\Delta t}$ and $L_{C,\Delta t}$ be the DG load (injected) and the total customer load respectively at a small time interval Δt while $C_{R,\Delta t}$ and $C_{W,\Delta t}$ be the retail price and wholesale price (corresponding to the time interval Δt) of electricity respectively.

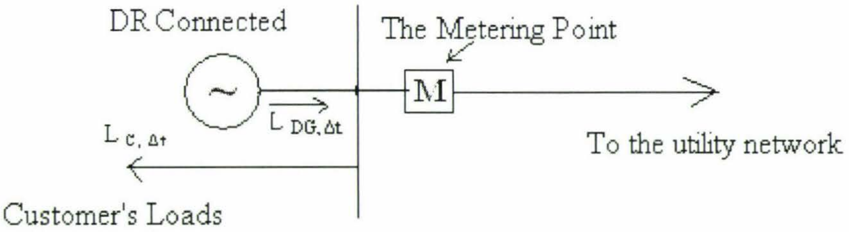

Fig. 5.4 : Illustration of the gross import/gross export metering concept[9]

If $L_{DG,\Delta t} < L_{C,\Delta t}$, the customer's revenue (i.e. avoid a cost) $= C_{R,\Delta t} * L_{DG,\Delta t} * \Delta t$ Eq. 5.1

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[8] *Of different metering scenarios possible, this is one of the more likely possibilities in an actual situation. This metering possibility was taken only for the purpose of obtaining a quick guide on the time of use and time of generation implications for Totara Valley. In actual DG systems modeling, and the performance and economics simulation, the other metering possibilities will be considered as described in chapter6.*

[9] *The name "gross import/gross export" is given because the meter profiles 2 separate profiles; an import load profile and an export load profile during any half hour interval. Two profiles can exist for any given time interval due to the intermittent nature of the loads and renewable energy sources (e.g. wind). These result in flow of energy backwards and forwards during a given time interval. The import load profile by itself is not the net import load profile. Similarly, the export load profile by itself is not the net export load profile. Hence the metering system is named "gross import/gross export" (see metering scheme 2a of Appendix D).*

On the other hand if $L_{DG,\Delta t} > L_{C,\Delta t}$,

$$\text{the customer's revenue} = \underset{\textit{(customer's avoided cost of energy purchase)}}{C_{R,\Delta t} * L_{C,\Delta t}} + \underset{\textit{(retailer's avoided cost of energy purchase)}}{C_{W,\Delta t} * (L_{DG,\Delta t} - L_{C,\Delta t}) * \Delta t} \qquad \text{Eq. 5.2}$$

The above mathematical expressions suggest that if $L_{C,\Delta t}$ and $L_{DG,\Delta t}$ are large and Δt corresponds to a peak period (during which time $C_{R,\Delta t}$ and $C_{W,\Delta t}$ are expected to be high) the customers would be able to avoid a substantial dollar cost which would otherwise have to be paid to the retailer while any surplus energy generation would produce a higher revenue. Apart from the revenue stream realised by avoiding grid energy and supply of energy to the retailer (Eq. 5.2), customer can receive additional revenue if the lines company does pay for supplied to the network during peak periods. For this to be realised the lines company should be facing a capacity problem and the energy/capacity needs to be dispatched at the right time signalled by the lines company (section 2.5.3.3).

In cases where a local lines company pays DG investors for the supply of firm energy/capacity[10] during peak periods (during which times the spot prices and line charges are also expected to be high), dispatching firm energy/capacity will accommodate both the interests of the DG investor as well as the lines company. Firm energy as applied to DG could be defined as electrical energy (kWh) that could be guaranteed to be delivered under terms defined by a contract between the DG investor and a utility (for example supply of an agreed quantity of energy during peak occasions signaled by the lines company). The contract among other things will stipulate when should the energy be delivered. In physical hardware terms such a firm energy commitment refers to utilisation of controllable generation sources or renewable distributed resources coupled with controllable energy sources.

The next important issue was to study how all the above mentioned important criteria could be physically implemented in Totara Valley, based on analysis made on the community.

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10. *The capacity of a power system is usually measured in kVA and not kW. Energy is the time integral of capacity, if the latter is measured in kW. In other words, if the capacity is measured in kW, the average capacity supplied during a peak period connotes a similar meaning to energy (kWh) supplied during the same period. However capacity in kVA is more directly linked to the current carrying capacity of network elements than kW and hence the use of the former (whereas kW = KVA*power factor). Payment for supply of kVA (as opposed to kWh) inherently recognises the fact that the lines company value energy as well as the power factor at which the energy is supplied. As mentioned in section 2.5.3.3 lines companies such as Orion NZ Ltd., pay small DG owners (through the incumbent retailer) based on energy for the capacity provided.*

5.5.2 Analysis of the electrical distribution system

In the case study community, each farm receives several electricity bills on account of having several installation control points (ICPs) for the houses (under residential tariff) and the commercial installations such as the freezer sheds and wool sheds (under commercial tariff). The typical electricity distribution configuration for each farm is illustrated in Fig. 5.5.[11]

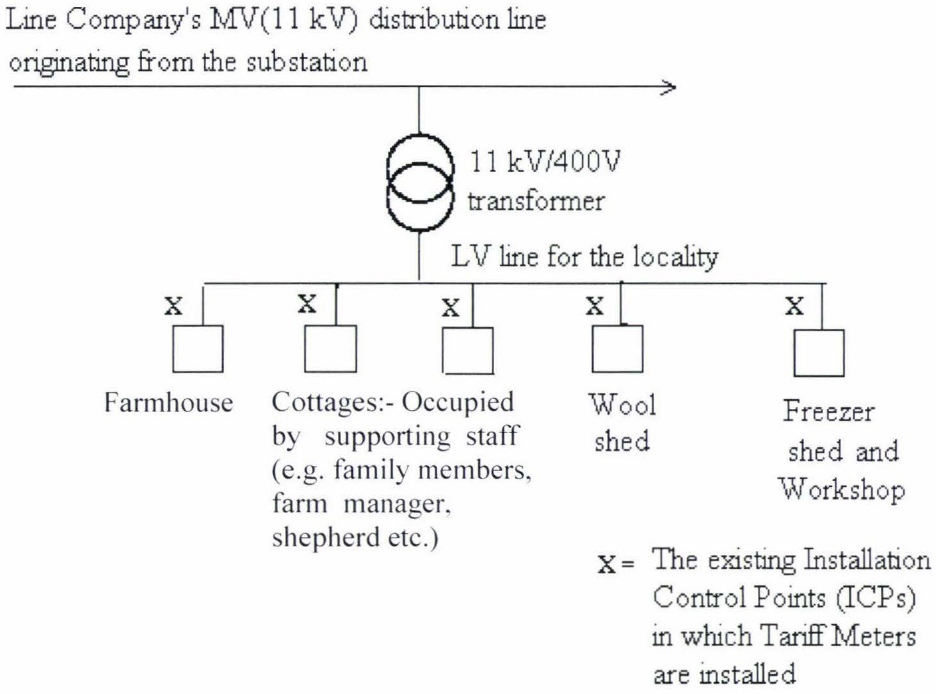

Fig. 5.5 The electricity distribution system for each farm at Totara Valley

The above observations lead the study to concentrating on two limiting criteria.

- The capacity of any DG unit connected to any single ICP of a farm is limited by the current carrying capacity of the ICP, as determined by the wiring system of the installation.

- The load profile of an individual ICP is likely to change significantly on a day to day basis (as opposed to the aggregated load profile of all the ICPs of the farm) which makes it difficult to gain a significant advantage from a demand side response such as operating a diesel generator for network capacity support.

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[11] *In case of farmer C however, a dedicated 11kV/230V transformer is installed as his farmhouse is situated at a fair distance away from the rest of the installations (i.e. farm manager's bungalow, freezer shed, woolshed etc.). Also the workshop electrical load in respect of Farmer A is connected to the woolshed*

In order to tackle these two issues effectively it was ascertained whether loads could be aggregated and metered at a higher hierarchical level. An aggregated load would yield a flatter and a more definitive load profile due to the load diversity of each user which in mathematical terms, would refer to a lower coefficient of variation of the load.[12] Equally important, it enables larger DG units to be connected to the lines company network.

The following two load aggregation possibilities were considered:

- aggregating loads at the transformer secondary level by establishing a single TOU metering point at the transformer (secondary side) instead of the existing tariff metering system (5.5.2.1); and
- aggregating the load at community level by establishing a single metering point for the whole community at the 11 kV distribution network (5.5.2.2).

5.5.2.1 Aggregating loads at the transformer secondary level

Aggregating loads at the transformer secondary level can easily be realised by a 3 phase 4 wire metering system due to lower voltage levels (230V per phase) involved as depicted in Fig. 5.6. However, the question remains whether this metering point could be considered as the ICP of the farm. ICP by definition establishes the legal interface that separates utility assets from customer's assets. If the transformer metering point is considered as the ICP, it means that the LV distribution assets (i.e. the supply line local to the farm area) owned by the lines company need to be transferred to the customer, which is an impractical situation. Therefore should transformer metering be undertaken at a rural community level, a transformer metering point could only be considered as a dummy ICP by a utility.

The other issue remaining to be addressed is how the utility tariffs could be designed owing to merging a customer's domestic load with the commercial loads. As far as ScanPower is concerned this is not much of a problem as they do not use price differentiation for small and medium customers on the basis of customer type (Appendix – F).

The initial discussions Massey/IRL had with Scanpower on the feasibility of using a single LV metering point for the whole farm were very promising.

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12. *The theoretical base for this concept was covered in section 4.3 (see Eq. 4.9)*

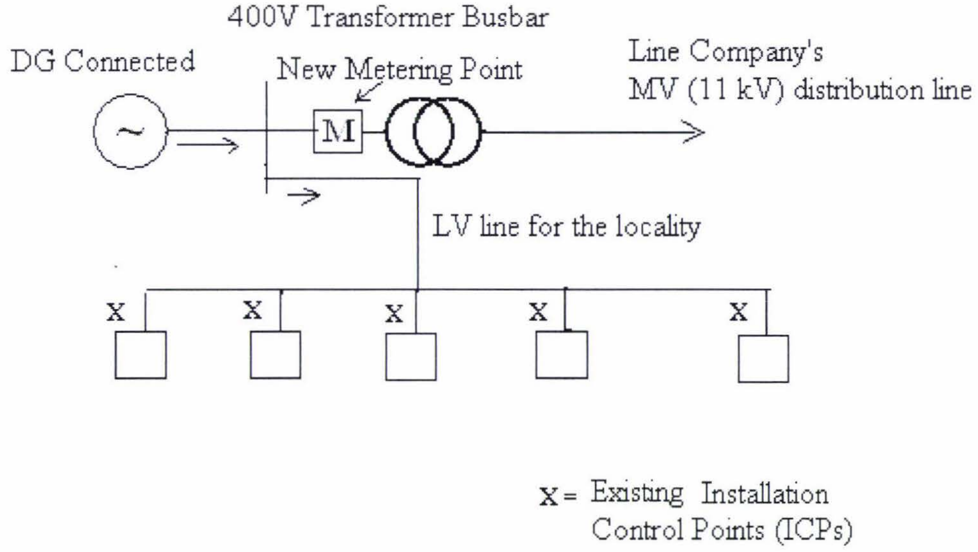

Fig. 5.6: Illustration of the proposed 3 phase 4 wire TOU metering system

5.5.2.2 aggregating loads at community level

For a community such as Totara Valley, where the 11 kV distribution spur line terminates at the community itself, the load could be aggregated by having a single line metering point as illustrated in Fig. 5.7. This configuration, which is an extension of the transformer metering concept, can accommodate larger DG units (whereas in the transformer metering case the capacity would be limited by the transformer capacity which is usually 30 kVA) [13] as all physical hardware could be hooked to the 11kV distribution line (via a larger transformer).

The question remained as to how such a single point community metering system would be embraced by individual community members. A survey conducted by Massey researchers (Irwing *et al*, 2000) on community owned and operated renewable energy schemes revealed that rural communities in New Zealand (especially those communities with intensive farming operations) are willing to corporate with each other if community owned and operated renewable energy schemes could be economically implemented. This implies that a single point metering for the whole community could meet community approval if one can justify the benefits the community would gain. Moreover, the new TOU tariff meter reading (total kWh) could be reconciled with the existing tariff meters each month and hence the share owed by the individual community members could easily be worked out by a simple accounting apportionment.

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13. *As an asset standardising policy, ScanPower uses 30 kVA distribution transformers wherever possible.*

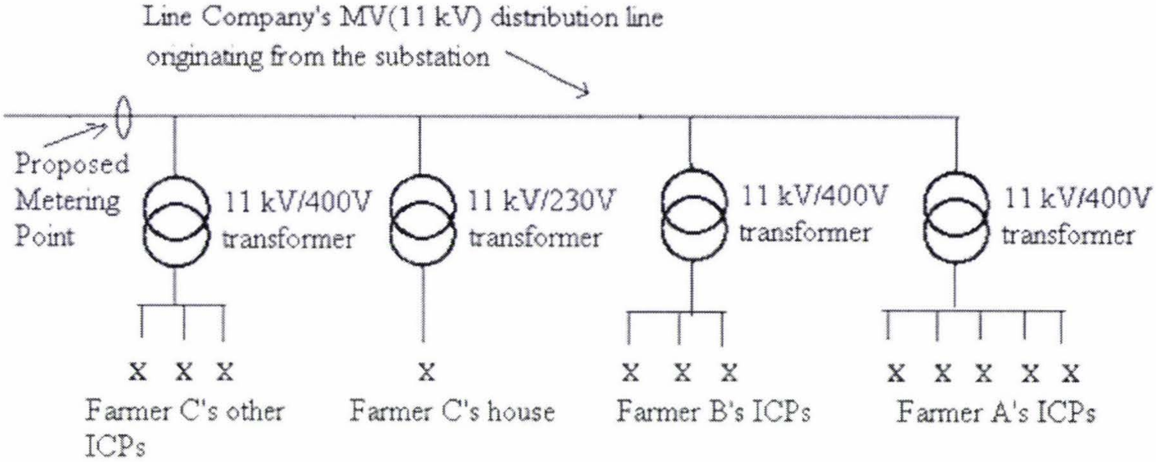

Fig. 5.7: Illustration of the single point gross import/gross export whole community metering concept for a fringe of the grid community[14]

5.6 FINALISATION OF THE LOAD METERING ARRANGEMENTS

The practical aspects related to the two metering methods referred to in section 5.5 were extensively discussed with IRL colleagues with a view to finalise a mutually acceptable load monitoring system. IRL have been researching DG for network support and power quality issues for some time and hence accommodation of IRL requirements were an integral part of the whole research.

Owing to the higher initial cost of hardware (11kV/LV voltage transformers and current transducers suitable for 11kV circuits) for a community metering system, it was decided that Massey and IRL should pursue the transformer secondary metering option. Since the nominal phase voltage of the transformer is 230V, the estimated hardware costs associated with this methodology was deemed within the budgeted range for the project. The fieldwork conducted for planning and implementation of the transformer secondary metering is enclosed as Appendix G. IRL who supplied the equipment was requested that load data logging should be based on both the voltage and current and not current signals alone as load voltage and power factor can change in real-time.

5.7 IDENTIFICATION OF KEY DATA COLLECTION REQUIREMENTS

The analytical part of this research for the most part refers to searching for optimum DG configurations and operational strategies for individual farmer owned DG projects as well

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[14] *Note that this configuration is not the preferred community-metering scheme, from a lines company perspective (section 8.3.1.3, p198).*

as large-scale community owned projects. The reason studying large-scale community owned DG systems was the positive impact its capacity (kW) has on its economic viability. A large-scale DG project is generally realisable through wider community participation due to financial and technical reasons. In order to study this, community loads were estimated from the case study load data as explained below.

ScanPower's 11 kV distribution configuration of Kumeroa/Hopelands areas was divided into five Zones (Fig. 5.1). Data on Zones B and C were collected in three ways:

- verbal and written communication with ScanPower in respect of the types (in terms of installed capacity and the nature of the loads) and the number of ICPs connected to the network;
- informal communication with farmers in Zone A (case study sample); and
- visits to Zones B and C.

The objective of the above exercise was to generalise the load research data obtained from the case study sample to synthesise a wider community load profile using statistical techniques (chapter 4) and personal judgment.

The reason for limiting the study up to Zone C was three fold:

- Generalising load data obtained from a small sample (Zone A) to a wider population would cause substantial errors, due to the diversity of the customers, in spite of making corrections for such diversity.
- For a successful community owned project there should be a greater degree of cooperation and understanding among the members of the community. The wider the community the less likely to be a greater cohesion among the community.

- It is highly unlikely that a utility would agree to extend many of the metering scenarios simulated (e.g. 11 kV gross import/gross export TOU metering) beyond a certain level because a large community can offset a considerable quantity of energy conveyed through a utility network by using larger DG units. This affects the returns of the lines company and the retailers.

5.8 DETAILS OF ACTUAL DATA COLLECTION

5.8.1 Load monitoring system for Zone A:

The dataloggers (model EUM 2000) that were installed in each farm to record load profiles of the three phases of the transformers (secondary side) were programmed to capture the average import power (watts) and export power per phase plus the three phase voltages (9 data inputs). Although price of electricity is established every half hour, the averaging time interval of the data logging system was set to two minutes in order to study the extent to which the community load profile and the voltage change in real-time. Half hour kWh consumption was later calculated from a spreadsheet program by averaging fifteen data records together. The hardware arrangement for the load monitoring system is illustrated in Fig.5.8.

Although it was requested ScanPower to install hardware for all the 4 transformers of the case study community (Fig. 5.7), it was later decided that installing a data logger for the single phase transformer that feeds electricity only to the farmhouse of farm C was not justifiable as there is no aggregation of load data. Load data of this farmhouse was separately obtained through already available digital energy meters with half hour load profiling capability (Model: SIEMENS S2A-100) which had been connected in series with the two utility tariff meters (one for any time use and the other for controlled).

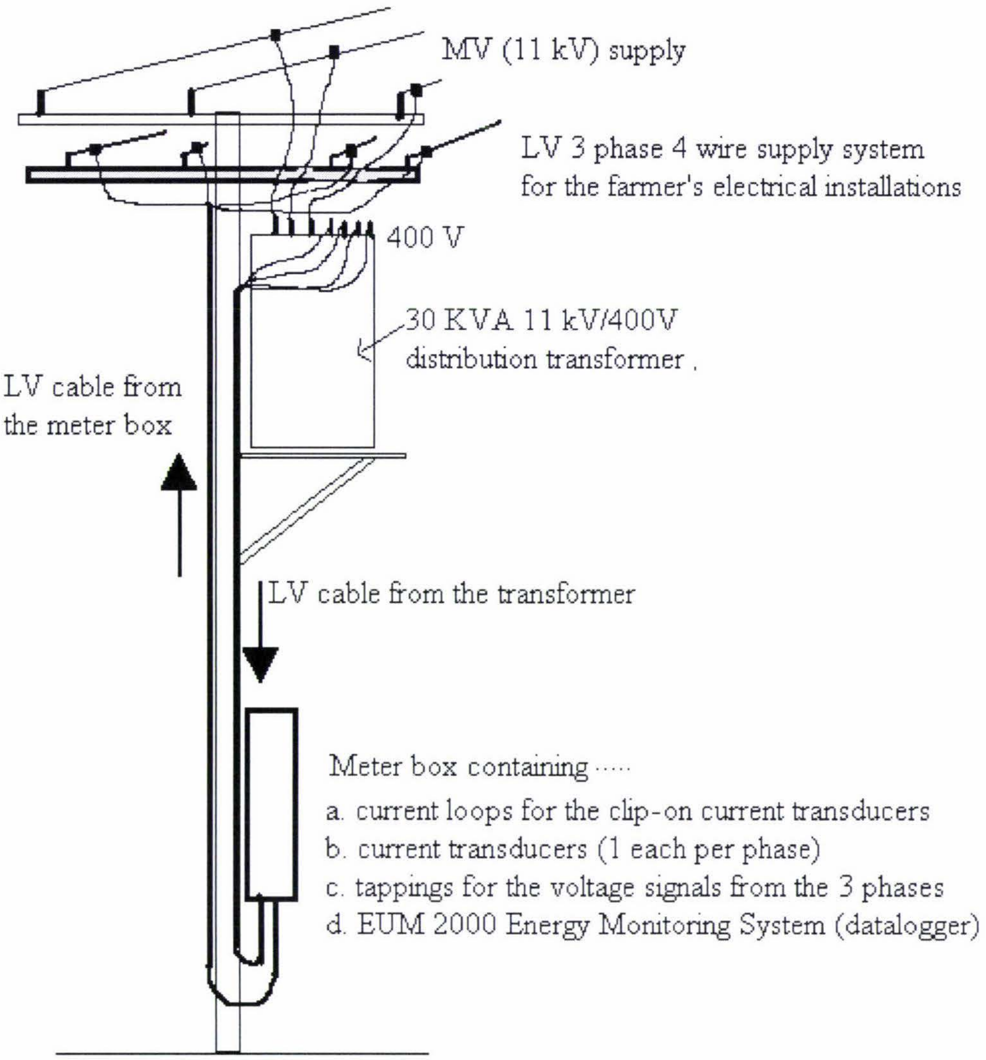

Fig. 5.8 The hardware arrangement for the load monitoring system of each farm

The objective of the above data collection procedures was two fold:

- to obtain necessary data to develop a load profile for each farm (section 6.2.2.1) and use it as input data in the DG model to output the performance and economics of a given DG configuration and operational strategy.

- to develop a composite load profiles for a Zones B and C by generalising the data using statistical techniques covered in section 4.4 (also see sections N.2 and N.3 of Appendix N).

The load profiles synthesised for Zones B and C were in turn used as input data in the DG model to output the performance and economics of a community owned and operated DG project with a known configuration and operational plan.

Unfortunately, ScanPower does not face a capacity problem and its pricing policy is entirely based on energy drawn from the GXP during daytime and nighttime, with the exception of its 11 large commercial customers, who are also charged for capacity drawn during winter on the basis of maximum demand at the ICP (Appendix - F). Since ScanPower does not face a capacity problem, it does not provide extra incentives to DG investors. For this reason, in addition to studying the performance and economics of DG configurations tailor made to Totara Valley/Kumeroa communities, a few hypothetical DG system configurations operating under an incentive scheme for supply of firm capacity were also analysed. For this purpose it was imagined that ScanPower faces a capacity problem due to overloading of the country feeder (section 6.3.2.1).

5.8.2 Electricity Price Data

The price of electricity is a key input variable in the DG model. Since the price is treated as a real-time variable (i.e. a value that updates every half hour) and assumed to be equal to the wholesale spot price of electricity, lines charges and the retailer's margin, data on the following variables were collated from the following sources.

- Wholesale Price Data: Historical half hour final wholesale price at the Haywards GXP published by M-co (in the URL http://www. nzelectricity.co.nz/electricity_prices/ physmark.htm).[14]

- Line Charges: Existing network charges as stipulated by ScanPower (Appendix - F), were used. On one occasion the line charges of Orion NZ Ltd was used to study how this totally different pricing strategy affects a DG investor and a lines company (Appendix Q, section Q2).

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14. *Haywards is one of the 3 reference GXPs, whose price data is publically available. The other two are Benmore and Otahuhu. These two are at a long distance away from Woodville Substation.*

5.8.3 Distributed energy system performance monitoring for Zone A

The performance of already installed solar hot water system and grid connected 100Wp PV modules were obtained as follows.

5.8.3.1 The Solar Hot Water system

The solar hot water system installed at the farmhouse of Farm A consists of four flat plate collectors (i.e. the solar panel), a 1200 litre hot water storage tank with a 2 kW auxiliary electric heater plus a forced circulation heat transfer system (heat transfer fluid conveying energy from the solar panel to the hot water tank being propylene glycol). The hot water tank also has a connection to the wetback system.

The monitoring system implemented included logging of several parameters (Table 5.1). The Campbell Scientific Instrument's CR10 datalogger used for this purpose was programmed to log data every 10 minutes. Accordingly, the solar irradiation data and temperature data recorded were average values over 10 minute intervals. The data measuring points are depicted in Fig. 5.9.

The rationale for selection of the above data measuring points was based on a number of reasons. Firstly, it was necessary to obtain the performance of the SHW system in terms of daily energy contribution towards hot water heating and link it with possible independent variables such as the hot water use (demand), solar isolation and ambient temperature etc. Secondly, it was necessary to study the electrical load profile of the auxiliary heater to study how it behaves as an electrical load. Finally, it was necessary to study how a wetback system affects the overall performance of a SHW system. The mathematical models used for the study are shown in Appendix - H.

Sr.	Parameter Measured	Details of the signal
1.	Global solar insolation (W/m2)	Analog signal injected through a semiconductor-based pyronometer (Campbell model LI 200X). Basis: "Global Solar Insolation" ∝ "Signal Voltage"
2.	Fluid flow through the flat plate collector (litres).	Pulse signals (TTL logic) injected trough a digital flow transducer. Basis: "Volume" ∝ "Number of Pulses"
3.	Hot water demand (litres)	Same as 2. above.
4.	Outdoor temperature.	Analog signal derived thorough a semiconductor current transducer (model AD 590JH)). Basis: "Signal Current" ∝ "Temperature (in ^{0}K)"
5.	Heat transfer fluid temperate from the flat plate collector.	Same as 4. above.
6.	Heat transfer fluid temperate to the flat plate collector.	Same as 4. above.
7.	Cold water temperature (storage input).	Same as 4. above.
8.	Hot water temperature (storage output).	Same as 4. above.
9.	Hot water temperature from the wetback heat exchanger.	Same as 4. above.
10.	Water temperature to the wetback heat exchanger.	Same as 4. above.
11.	Heat transfer fluid circulation pump run time (seconds).	Analog signal whose average voltage is proportional to the pump runtime.
12.	Electrical energy consumption of the auxiliary heater.	Pulse signals injected trough a digital energy meter (SIEMENS Model S2A-100). Basis: "Energy (kWh)" ∝ "Number of Pulses"

Table 5.1: The details of parameters logged in respect of the solar hot water system of Farm A

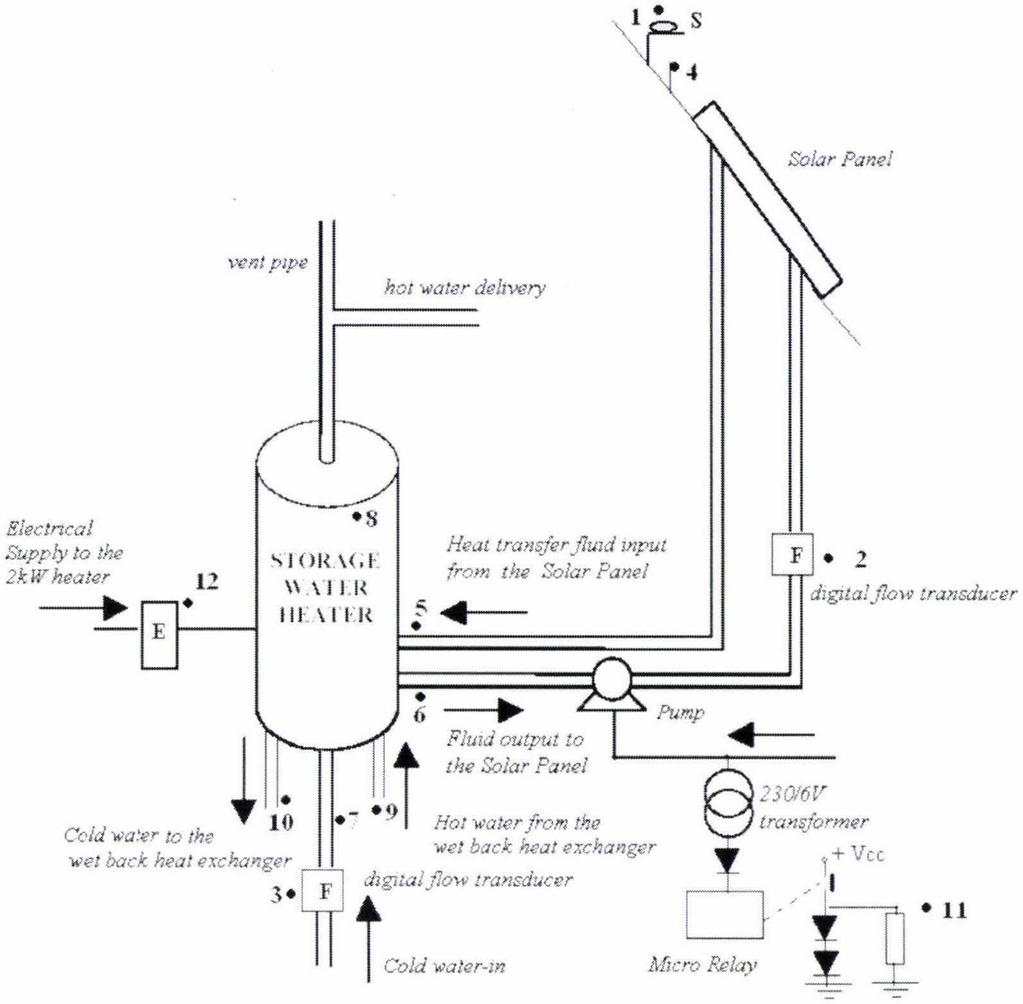

Fig. 5.9 Illustration of metering points of the solar hot water system of Farm A

5.8.3.2 The 100 Wp PV modules

The original objectives were to study the monthly energy delivery performance and the economics of a 100Wp ac PV module,[15] and to study the extent to which a theoretical load profile derived on the basis of PV module and inverter parameters would differ to an actual half hour load profiles measured.

The SIEMENS S2A-100 TOU energy meters supplied for connection to the 100Wp PV module output were not sensitive enough to capture a low load for profiling. However it was observed that although the energy meter profiling memory does not capture the half

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[15] *Each ac PV module is equipped with 2 Nos. SOLAREX Model MSX 50 PV modules (each rated at 50 Wp) and one single phase grid interactive inverter model OK4-100 (rated 100W at the dc side) manufactured by NKF electronics Holland. The inverter has an inbuilt maximum power point tracer.*

hour load profile, the calibration LED of the meter does actually pick any low load exceeding the meter creep current (50mA approximately, which is equivalent to 12W approx.). Therefore a pulse signal was derived from the meter LED via an optical coupler and hard wired to the data logger used for the SHW system so that the load profile data could be captured using the meter calibration constant of 1000 LED impulses/kWh.

Unfortunately due to a suspected fault in the inverter of the PV module, the above system never functioned properly. The tests done on the hardware are enclosed as Appendix - I for reference purposes. The actual monitoring was relegated to collecting monthly energy generation data from the PV modules at Farms B and C.

5.9 ELECTRONIC FILES CONTAINING RAW DATA

Data collected from the dataloggers are included as MS Excel files (along with supporting text files) under the directory "Kumeroa data" in the CD ROM supplied with this publication. Note that data has been collected for 6 months only (01 March 2003 to 31 August 2003). In respect of time series parameters that required one full year's data, the balance data required were estimated according to the procedure described in section 6.3.1.

CHAPTER 6

Modelling of Distributed Energy Systems

This chapter describes how grid connected distributed generation (DG) and storage systems were modelled for studying the performance and economics of different DG configurations, metering schemes at different scales of applications, both from the point of view of an investor as well as a lines company.

The salient feature of the DG model is the treatment of the 'price of grid connected electricity' as a time dependant variable. The model also considers any financial incentive in the market for injection of firm capacity (or firm energy) to the network. In essence the model enables one to formulate demand side strategies to take advantage of all the favourable price signals.

The model is a generic one which could be applied to most common small and medium scale grid connected DG applications in New Zealand. It would be of use to a DG investor/entreprenur to ascertain the financial viability of a proposed DG project operating under a given market environment. It would also be useful for a lines company to formulate its pricing strategies.

6.1 KEY DESIGN CONSIDERATIONS

6.1.1 A distributed energy resource system as a physical system

Like other physical systems, a grid connected DG system can assumed to be a collection of interconnected systems that process inputs (received from the external environment) into outputs. In particular, a DG system can be thought of as a physical system that converts renewable and fossil fuel energy into electrical energy (Figs. 6.1 through 6.3).

The manner in which the DG output (i.e. electrical energy) is interfaced with the grid determines the designated task of the system. Fig. 6.1 and 6.2 illustrates a DG system interfaced through the customer load. In physical hardware terms, the interface could be a wiring system for either a net metering or a gross import/gross export metering system. In such cases, the electrical energy released from the system should meet the customer load first. It should also meet any electrical energy-charging load if a distributed resource such as a battery or pumped hydro unit is included in the system. The difference between the two situations is the state of the DG system. Fig. 6.1 illustrates a system state where the DG system is having sufficient input energy (e.g. wind) to produce electrical energy more than what the customer and the energy storage devices demand.

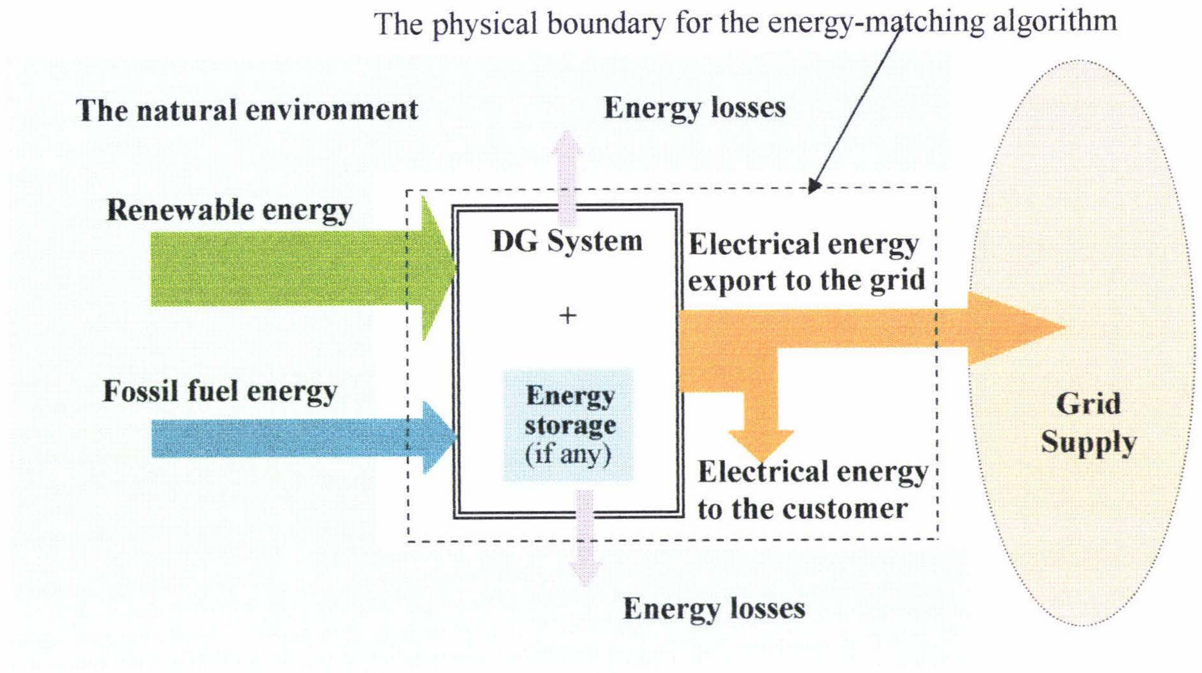

Fig. 6.1: DG system exporting excess electrical energy in completing its designated tasks

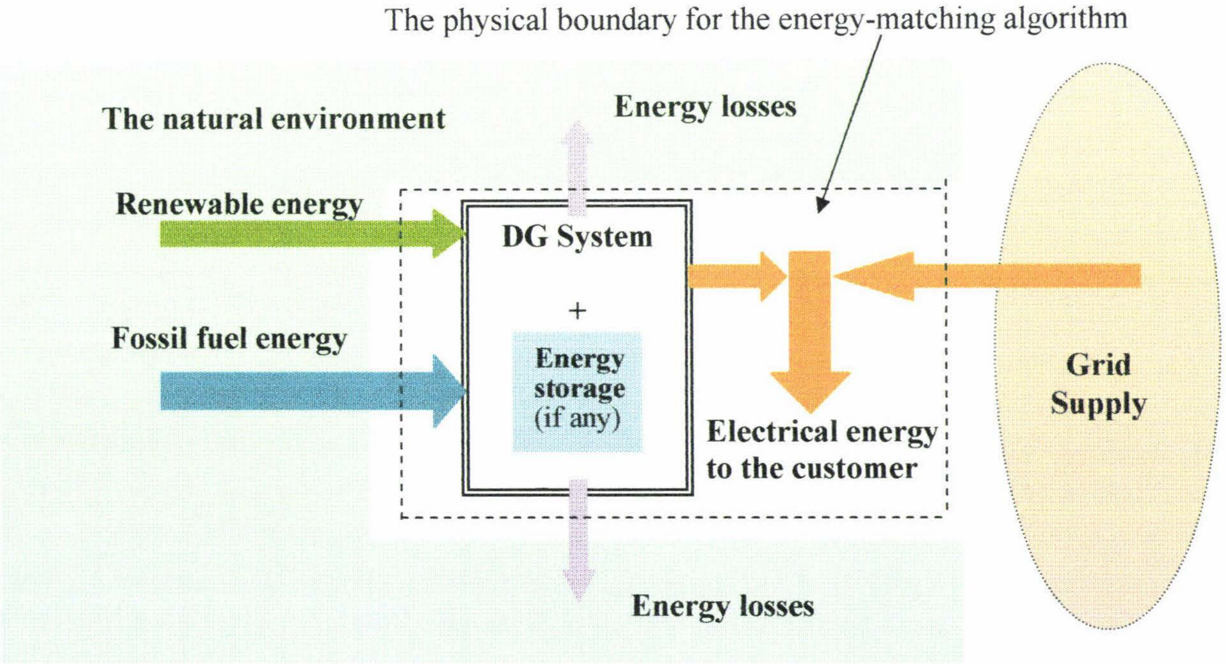

Fig. 6.2: DG system importing the balance electrical energy in fulfilling its designated tasks

Fig. 6.2 illustrates a state where the same DG system is not having sufficient input energy to produce electrical energy that the customer and the energy storage devices demand thereby importing energy from the grid to meet the deficiency.

Fig. 6.3 illustrates a different DG system that is not interfaced through the customer load. In such a case, the designated task of the DG system is to release electrical energy to the grid only. In physical hardware terms, the interface would be a wiring arrangement for separate generation (grid injection) and load (grid off take) metering system (Fig. 6.13).

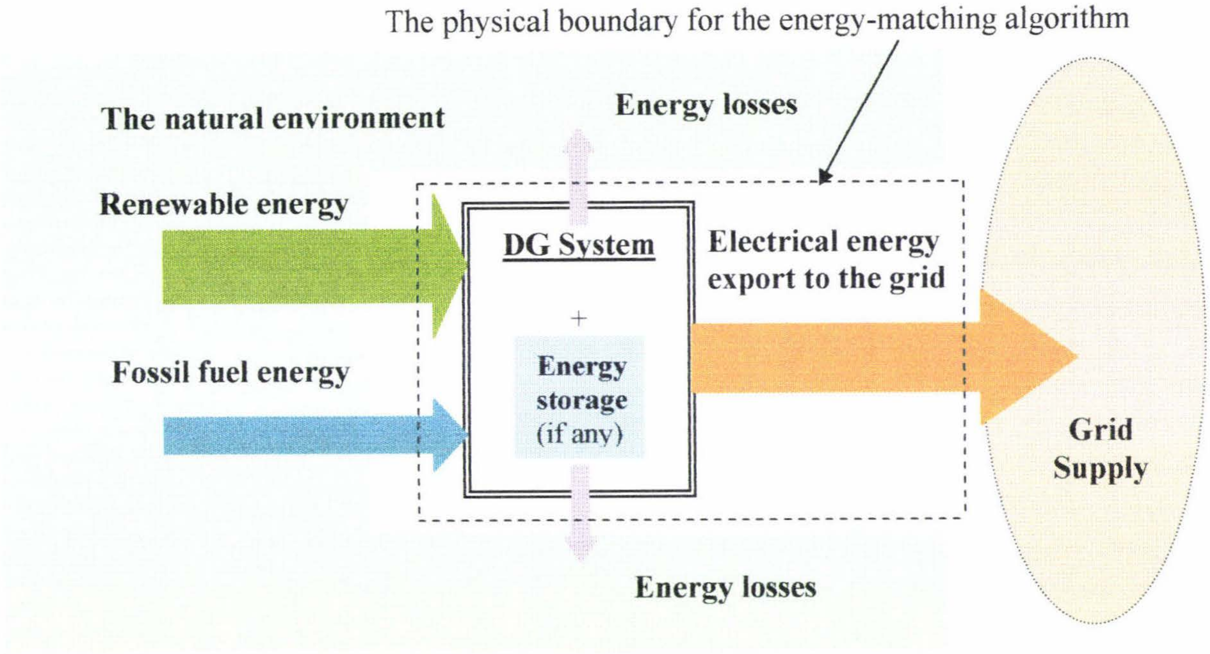

Fig. 6.3: A DG system with no designated task involving energy supply to the customer

Irrespective of the designated task, in order to conform with the law of conservation of energy, any DG system should be inherently stable in that energy received from the external environment during a given time interval should be equal to energy released to the external environment during that time interval in the form of electrical energy and losses, after allowing for any energy that would be stored within the system.

6.1.2 Energy matching interval

Since electrical energy is matched and reconciled every half hour in New Zealand, the computer simulated DG model described in section 6.2 was designed to match input energy with output electrical energy every half hour over a full cycle of one calendar year.

The time variables 'renewable energy input' and 'electrical energy consumed by the loads' were calculated based on average power within the time interval. For example if $\overline{P}$ is the average customer electrical power consumption (in kW) over a half hour interval, the energy consumed by the customer during that interval would be $0.5\overline{P}$ (in kWh).

Although it was possible to use half hour input and output parameters averaged on a seasonal basis to reduce the volume of data from 17520 data records (i.e. 48*24*365) to 384 data records (i.e. 48*24*4), it was not considered primarily because such an averaging subroutine would not accurately deal with the issues described below.

- Nonlinearity: Averaging input and output parameters means making the inherent assumption that model inputs and outputs are linearly related. This is not so in some cases. For example, the electrical power output of a wind turbine is not proportional to the wind speed. While root mean cube of the wind speed would be more accurate as an average value than the simple average wind speed, in practice the relationship between wind speed and wind turbine power output is determined by the wind turbine power curve.

- Probabilistic events: Contingency events such as high load peaks as faced by a lines company are essentially probabilistic events. Since such events do not occur every day, averaging of load over a season would not enable a researcher to simulate load peaks and the corresponding demand side responses (including dispatch of DG) accurately.

- Oscillating electrical energy flows: DG systems which are interfaced through "gross import/gross export metering systems" could record energy flows in both directions within a half hour interval due to the intermittent nature of renewable energy and the customer loads. This is because energy could be exchanged back and forth from the grid several times within a half hour time interval. Averaging energy flows would cause only one just state; either a gross export state (if generated electrical energy is greater than energy consumed by the load) or a gross import state (if generated electrical energy is less than energy consumed by the load) for the whole season for any given half-hour period. Such a situation is not practicable.

6.1.3 The suitable application software platform

As explained in sections 6.1.1 and 6.1.2 and will be clearer from section 6.2, the study of the performance and economics of a DG system was accomplished through simulating a DG system which was assumed to be in steady state equilibrium with the external environment at every half hour, during a calendar year. Accordingly, energy matching of 17520 equilibrium states of the DG system was one of the primary tasks executed by the computer. The model was developed in a MS Excel platform for the several reasons.

- Ease of sensitivity analysis: In order to search for optimum DG configurations, it was necessary to alter model parameters and observe their effects quickly. Doing such sensitivity analysis is easy in a spreadsheet-based program.

- Ability to reproduce similar calculation structures: MS Excel can quickly reproduce a calculation structure that has been established for one data record (corresponding to a given half hour) in other data records (corresponding to other half hours)[1].

- Ability to accommodate logical tests: Worksheet functions such as "IF" function and "AND" function can handle a range of situations relevant to a DG system.

- Ability to conduct a range of statistical and probabilistic mathematical operations: As a probabilistic decision tool, the DG model draws several variables based on random events (e.g. days in which critical peaks occur) which can easily be accomplished by MS Excel. It was also used to fit appropriate polynomial regression equations (from published data) in the model, for determining the output power of different distributed resources, initial costs etc.

6.2. THE COMPUTER PROGRAM

The computer program was named "DG+" for reference purposes and is supplied in a CD ROM at the back of this publication. The size of the program file is 107MB and requires a fast Pentium PC with a memory of at least 256MB RAM to run smoothly.

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[1] *Due to various logical tests performed, it was not always possible to write the cell formula in the first record and drag it down it to other records blindly.*

Table 6.1 is a mere reproduction of some adjacent cells in the central worksheet to illustrate the colour code. Category 1 covers a wind turbine whose rated capacity is less than 50 kW while category 2 covers a wind turbine whose rated capacity is equal or above 50 kW (see section 6.2.7.1 including Fig. 6.15 as well as Fig. L.1 of Appendix L for details).

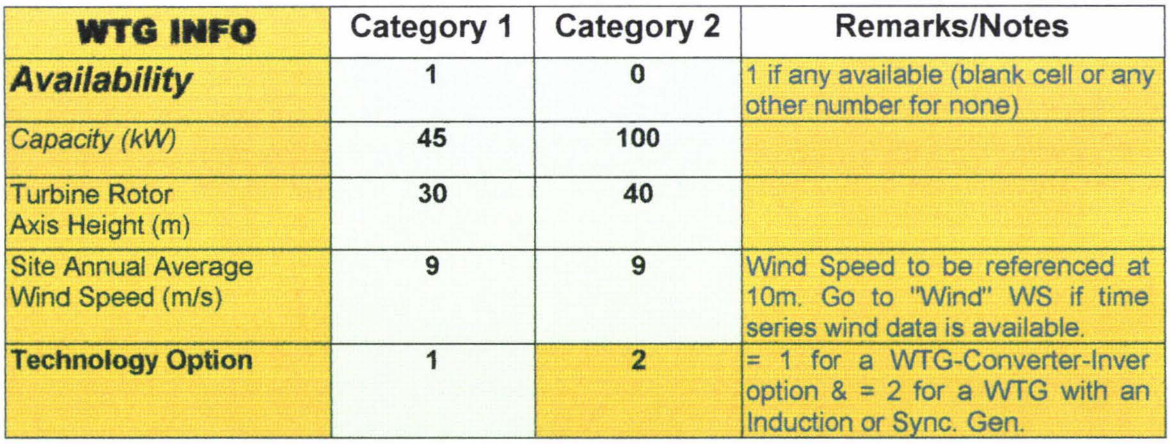
The number of steps used to derive results could have been reduced but was not attempted because of possible difficulties in checking for "bugs." A commercial version would need to be made to be more user friendly.

6.2.1 The structure of the program

The program was developed as a single file consisting of nine worksheets. The first worksheet named "intro" introduces the program to the user, describing the scope of its application. The other eight worksheets were interlinked (Fig. 6.4) and the protocol adopted with regard to the program structure is outlined in sections 6.2.1.1 through 6.2.1.4.

6.2.1.1 Input data

The cells to which data needs to be inputted are colour coded light green. Instructions are provided in *blue colour font* against the cells where necessary to input data. Table 6.1 illustrates an example.



WTG INFO	**Category 1**	**Category 2**	**Remarks/Notes**
Availability	**1**	**0**	1 if any available (blank cell or any other number for none)
Capacity (kW)	**45**	**100**	
Turbine Rotor Axis Height (m)	**30**	**40**	
Site Annual Average Wind Speed (m/s)	**9**	**9**	Wind Speed to be referenced at 10m. Go to "Wind" WS if time series wind data is available.
Technology Option	**1**	**2**	= 1 for a WTG-Converter-Inver option & = 2 for a WTG with an Induction or Sync. Gen.

Table 6.1: An extract from the central worksheet of the Excel spreadsheet model showing input data cells and remarks

A few cells are colour coded in grey and filled with default values which need not be changed for New Zealand applications (e.g. longitude of the site and the local time meridian in the *solar worksheet*).

The Structure of the Computer Model

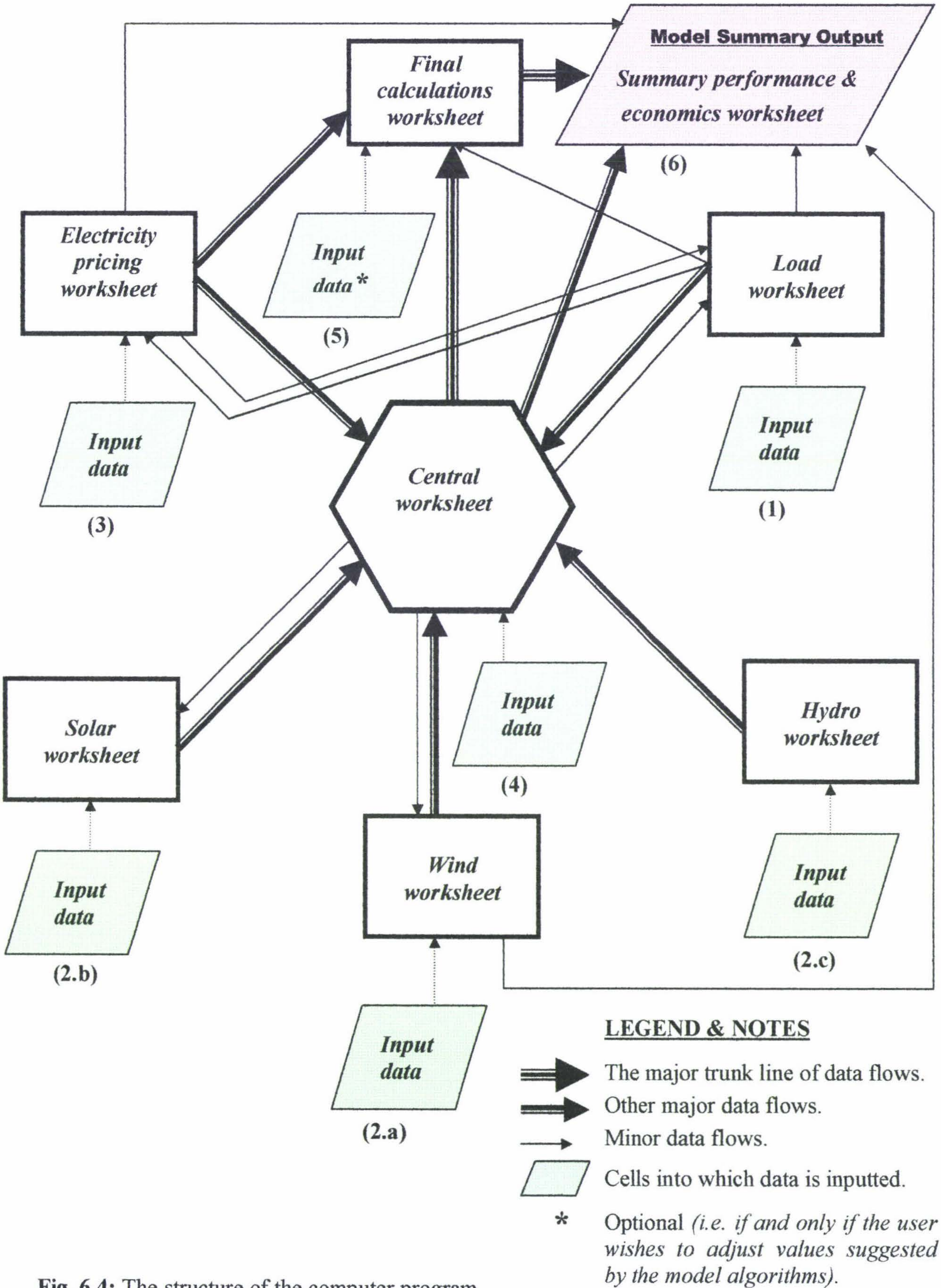


Fig. 6.4: The structure of the computer program

6.2.1.2 Derived data

There are some *colourless cells* in which data appear in *red boldface font*. This indicates to the user that the data contained in these cells, which intuitively appear to be input data, have in fact come from data inputted elsewhere (see example Table 6.2). The user has no control over data appearing in *red boldface colour* but can trace back to the original source (or sources), if required, for any changes. In Table 6.2, the figures in *red boldface font* refer to the start and stop time intervals of a fuelled generator set. The user cannot make any changes to the values therein but can trace then back their source, *electricity pricing worksheet* if any changes need to be made (sections 6.2.1.3 and 6.2.6).

Season	Summer	Autumn	Winter	Spring
Start Int. for FGS 1	**0**	**0**	**37**	**0**
Stop. Int. for FGS 1	**0**	**0**	**37**	**0**

Table 6.2: An illustration of derived data on the operation of a fuelled generator set extracted from the *central worksheet*

6.2.1.3 The control philosophy

Certain algorithms in the *load worksheet*, *electricity pricing worksheet* and the *central worksheet* (sections 6.2.2, 6.2.6 and 6.2.7) are based on a predetermined DG control philosophy to take advantage of the price signals effected by a lines company. Fig. 6.5 illustrates the control system in relation to other key physical hardware such as DG units and tariff metering equipment [2].

It is assumed that a lines company exercises two levels of peak shaving. The first level termed *control period load shedding* refers to selective switching off of controllable loads which are supplied with ripple receivers on the customer side. The objective of a lines company in this instance is assumed to be fulfillment any requirement agreed with the energy retailers and reduction of daily peaks in order to increase the load factor to acceptable levels and subject the network assets such as transformers on a more favorable *duty cycle* with the presumption that such a *duty cycle* would reduce maintenance costs and extend the lifetime of network assets. It is assumed that *control periods* are not emergency periods, as far as a lines company is concerned. In general, all lines companies in New Zealand exercise this level of peak shaving.

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2. *The control philosophy illustrated in Fig. 6.2 is applicable to a large customer or a community owned DG project only. A small customer cannot gain an economic benefit by investing in additional load control and/or dispatchable DG. See sections 8 and 9 for simulation results and discussions.*

Since the uncontrollable load is not manipulated by the control system it is not depicted as a separate entity in Fig. 6.5.

The ripple-controlled signals depicted are signals transmitted by the lines company notifying "critical peak periods." In order to activate the control system, a ripple receiver (owned by a customer to control his /her DG system) thus intercepts the ripple signals. One may also call these ripple-controlled signals, "lines company price signals" (note that there are other price signals such as spot price hikes).

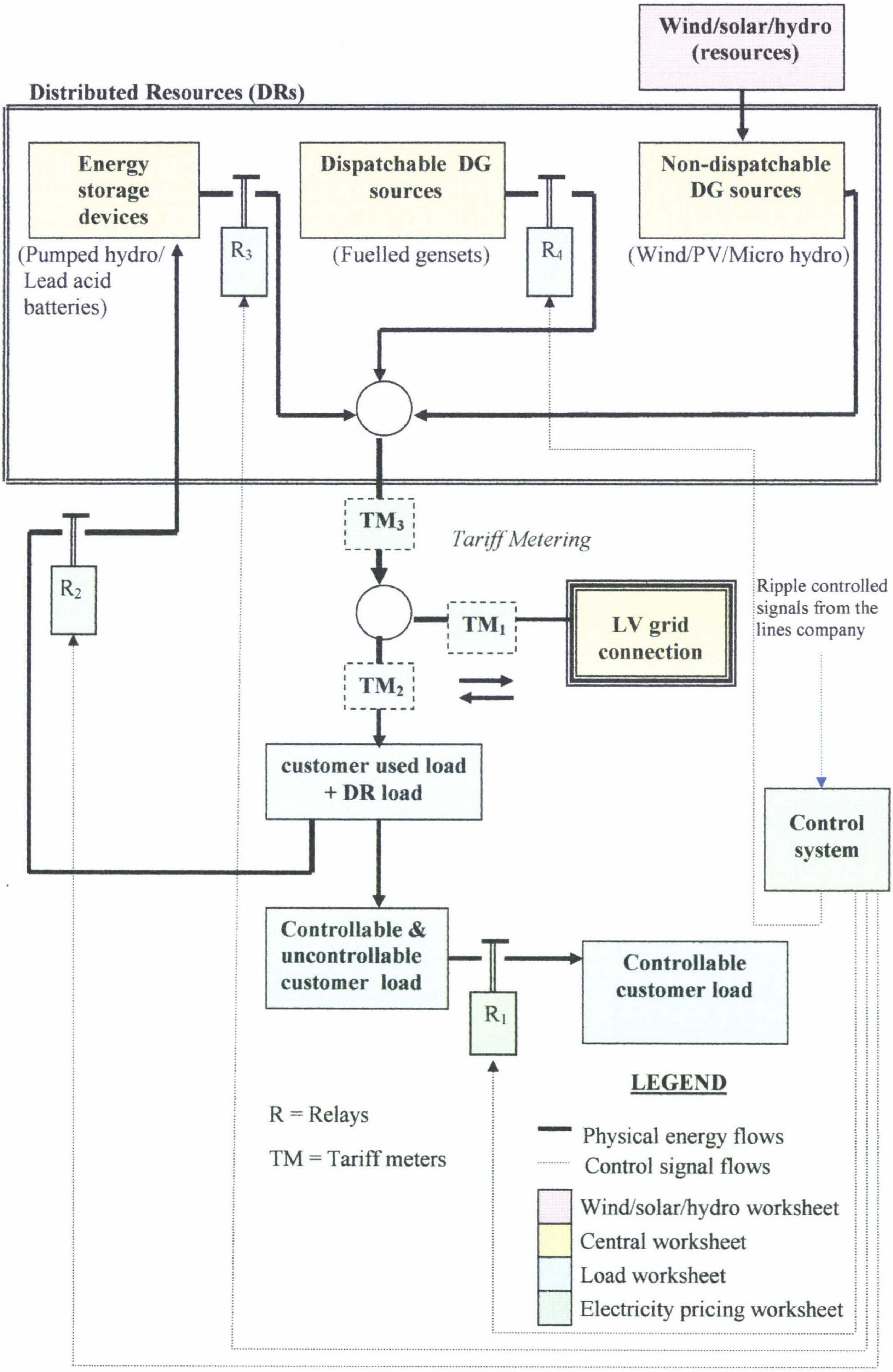

Fig. 6.5: Illustration of energy flows and control signal flows of the DG system

The second level of peak shaving, which is termed *critical peak period load shedding* is assumed to be administered to alleviate more severe network strains through such contingency measures as shedding of all the controllable loads together (as opposed to selective switching) and even under voltage operation of the network. Not all lines companies face such situations however. In a practical context, *critical peak periods* are expected to exist only for a short period (e.g. 30 min to 2 hours on some days, typically in the winter), which could be managed by contingency planning without capital investment in capacity expansion. Hence as an alternative to capacity expansion, it was assumed that a lines company facing short spells of network strains would pay DG owners for firm capacity (or firm energy) supplied during the *critical peak period* (i.e. payments for *peak lopping*). Since the lines companies who face such problems base their pricing options to some extent on energy consumption during *critical peak periods* (e.g. Orion NZ Ltd.), customers provided with appropriate meters, can avoid a portion of line charges by switching off any additional controllable load during the *critical peak periods*.

The control circuit of the DG system (and hence the program algorithms) was designed to achieve the above tasks for the benefit of the lines company and the DG investor. In particular, all or some of the following three specific tasks (depending on the size of the DG system and the local lines company) were assumed to be executed:

- accepting *critical peak period* warning signals[3], starting up the dispatchable DG sources and energy storage devices for injection of energy to the grid[4] and paralleling and shutting down the units upon receipt of the *critical peak period* commencement signal and the *critical peak period* end signal respectively [5];

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3. *Orion NZ Ltd, for example, transmits a warning signal to alert large customers, 15 minutes before any form of load control is exercised.*

4. *In a practical context, the control system may also be programmed to conduct distributed resource "pre start checks" on a regular basis (e.g. scanning of diesel engine fuel oil and lube oil tank levels, state of charge of the battery bank, pond levels of micro hydro units and so on) as a safety and reliability measure.*

5. *The reason for shutting down the units is that the revenue received by the DG owner for grid injection outside peak periods would only be for the energy supplied to the retailer. A retailer would buy the product at a price that would otherwise have to be paid to the generators for buying the same quantity of the product at the same time from the wholesale market. The net revenue from energy sales per se is usually not sufficient to cover the costs due to low spot prices (see Fig. 7.1 and 7.3). The model allows overriding the controls (notionally), for studying special cases. For example studying the effect of selling electricity during times in which the spot prices remain high (on average) could be accomplished by aligning the peak period times with high tariff times and setting the rate that is being paid for firm energy (or firm capacity) as zero.*

- switching off the circuit breakers/contactors of controllable loads[6] (i.e. loads which are not connected to ripple receivers) upon receipt of the *critical peak period* signal and switching on the circuit breakers/contactors as soon as the *critical peak period* ends.

- charging energy storage units (e.g. starting a pumped hydro unit as a water pump) at the beginning of a pre-programmed time (say 2.00 am), when the network is expected to be lightly loaded and spot price lowest, and shutting down the units once they are fully charged.

6.2.1.4 Timing of events simulated

The model assumes that a lines company would always signal the commencement of a *critical peak period* (though ripple control) at the beginning of a *half hour interval* and that it would withdraw the *critical peak period* at the end of a *half hour interval*. Accordingly, the duration of any *critical peak period* (in hours) would be a multiple of 0.5. As controllable DG units and energy storage units (in discharge mode) follow the ripple signal, these DG units shall, by default, start and stop during the commencement and ending of a *half hour interval* respectively.

The model also assumes that the control system would give a signal to charge energy storage devices (batteries and/or pumped hydro) during the beginning of a *half hour interval*. As regards the ending of energy charging however, the model will calculate the actual durations the units need to be charged to attain the 'full charge state' and place the end times appropriately, properly accounting for energy balances. The user has no control over this activity (see section 6.2.1.2). With regard to commencement and ending of events, the model follows the following protocol:

- Commencement of an event: The user has to enter the half hour time interval that has just commenced. For example, the start interval "37" for the fuelled generator set means that it starts (when the control system receives a ripple signal of course) at the commencement of the 37th half hour time interval (Table 6.2).

---

[6] *The controllable loads, as far as the computer model is concerned, are additional loads which could be kept switched off for a few hours (typically less than 1 ½ hours) during the morning or the evening peak. This is a DG owner induced intervention as opposed to a lines company induced intervention. As far as the computer model is concerned, all loads that are equipped with the ripple controllers supplied by utilities are uncontrollable loads.*

- Ending of an event: The user has to enter the half hour time interval that has just elapsed. For example, the stop interval "37" for the fuelled generator set means that it stops at the end of the 37th half hour time interval (Table 6.2).

6.2.2 The *load worksheet*

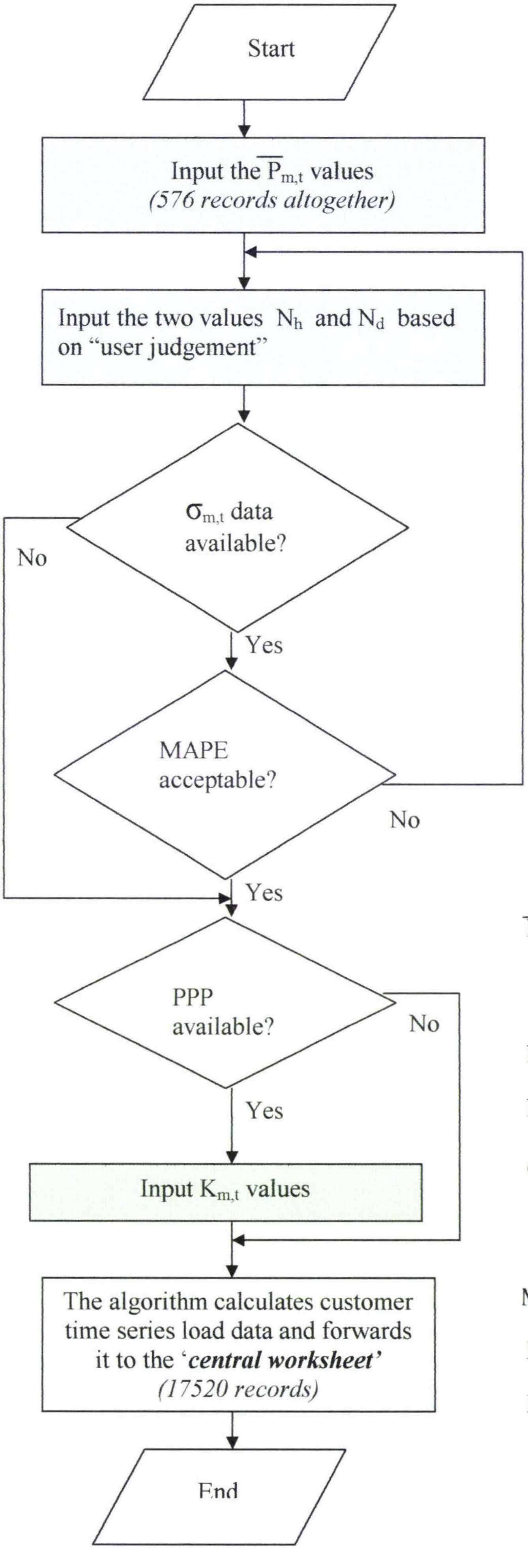
The primary function of this worksheet is to generate the customer load, for every half hour of the calendar year simulated and forward it to the *central worksheet.* Once the customer load for every half hour of the calendar year is simulated, the load worksheet also calculates the summer and winter load factors, the peak, the mean and the median loads as customer load summary information which it forwards to the *summary performance and economics worksheet.*

The *load worksheet* also reproduces (from the *central worksheet*) load data of energy storage devices operating in *charge mode.*

6.2.2.1 Synthesis of time series customer load data

To generate 17520 load data records, as the minimum requirement, the computer model requires the average (mean) customer load for each half hour for every month (i.e. 48*12 = 576 records). The procedure of the synthesis of customer load data is depicted in flow chart format in Fig. 6.6.

The model does not distinguish between weekdays and weekends/public holidays. The user can also input the percentage of customer load that could be avoided, if a *critical peak period* signal is received from the lines company (refer to the $K_{m,t}$ values in Fig. 6.6 and column (9) of Table O.1 in Appendix - O). This of course is relevant only if the lines company is basing its product prices, to some extent, on its *critical peak period* demand. The impact of not having a particular electrical appliance at a customer's disposal can change depending on time. Therefore controllable load during a *critical peak period* depends on the time of the day the signal is received and its duration. Hence, the



The abbreviation

$\overline{P}_{m,t}$	*Mean customer load (controllable + uncontrollable) for each month during each half hour period (12*48=576 values).*
N_h	*Half-hourly noise.*
N_d	*Daily noise.*
$\sigma_{m,t}$	*Standard deviation of the total customer load (controllable + uncontrollable) for each month for each half hour period.*
MAPE	*Mean average percentage error.*
PPP	*Peak period pricing.*
$K_{m,t}$	*Percentage controllable load for each month during each hour period.*

Fig. 6.6: The flow chart of the customer load synthesis algorithm

user needs to input percentage values for each half hour of each month for the whole year. For most cases, it would be a constant value all the time.[7]

As evidenced in Fig. 6.6, to complete data inputting, two other parameters need to be defined by the user; the *daily noise* and the *half*-hourly *noise*.

The *daily noise* (abbreviated as N_d) was assumed to be the standard deviation of a hypothetical *normally distributed random variable* (abbreviated as δ_d). This was assumed to be perturbing an otherwise constant customer load (for a given half hour interval of a given month) by a factor δ_d, on a day to day basis (NREL, 2002). The load influencing factors, whatever they may be (e.g. a hot day, a day with more house occupants, a timber saw mill sawing a denser variety of timber which it does not normally deal with), were assumed to be affecting the customer load uniformly throughout the day. Accordingly if $P_{m,t}$ was the mean load of a customer during a given half hour time interval in a given month, then by definition the actual load would be;

$[P_{m,t} + \delta_d * P_{m,t}]$,

assuming the customer load was only affected on a day to day basis. It also follows that mean value of the random variable δ_d would be zero.

In order to describe all of the random factors that affect the customer load, a second hypothetical *normally distributed random variable* (abbreviated as δ_h) was introduced to the model which was assumed to be affecting (perturbing) the customer on a half-hourly basis (NREL, 2002). The load influencing factors in this instance were assumed to be mostly to do with customer behaviour. In a similar logic to the *daily noise*, it was assumed that δ_h has a mean value of zero and a standard deviation equal to N_h, termed the *half-hourly noise*. Accordingly if $P_{m,t}$ was the mean load of a customer during a given half hour time interval in a given month, by definition, the actual load would be;

$[P_{m,t} + \delta_h * P_{m,t}]$,

assuming the customer load was only affected on an hour to hour basis.

---

[7]. *Having different values would mean more control hardware; relays, contactors etc., which all add to the cost.*

Combining the two influence factors together, the total customer load at a given time interval of a given month $P_{m,t}$ would be given by;

$$P_{m,t} = \overline{P_{m,t}} + \overline{P_{m,t}} * \delta_d + \overline{P_{m,t}} * \delta_h = \overline{P_{m,t}} * (1 + \delta_d + \delta_h) \qquad \text{Eq. 6.1}$$

MS Excel does not have an inbuilt mathematical function to generate numbers drawn at random from a *normal distribution*. It however can generate numbers drawn at random from a uniformly and independently distributed probability distribution between zero and unity. In order to generate the 365 values of δ_d and 17520 values of δ_h, the model uses the Box-Muller mathematical transformation to generate these values from random numbers generated by MS Excel. According to this transformation, if x_1 and x_2 are uniformly and independently distributed numbers between 0 and 1, then z_1 and z_2 as defined below, have a normal distribution with a mean zero and a standard deviation of unity.

$$z_1 = [-2(\ln x_1)]^{0.5} \cos (2\pi x_2) \qquad \text{Eq. 6.2}$$
$$z_2 = [-2(\ln x_1)]^{0.5} \sin (2\pi x_2) \qquad \text{Eq. 6.3}$$

The calculation of 17520 $P_{m,t}$ values using equations 6.1 through 6.3 using paired random numbers is graphically illustrated in Table O.1 (Appendix-O). Once $P_{m,t}$ values are generated the model recalculates the standard deviations of them corresponding to each half hour of each month (i.e. 576 values). If the user is able to ascertain the actual values of the standard deviations through load research, then the user can improve the quality of $P_{m,t}$ values generated by the computer. The model outputs the mean average percentage error (MAPE) between the standard deviations of synthesised data and standard deviations derived based on load research data. Note that the model assumes load research data as reference (actual) data. If MAPE is more than say, 12%, the user has to readjust the N_d and N_h values and then observe the outcome (Fig. 6.6). The process is continued as an iterative process up until the user observes the lowest possible MAPE value.

The statistical definition of MAPE is that if there are '*n*' observations between actual and calculated data in respect of a variable V whose i^{th} actual and calculated observations are denoted by $V_{i,actual}$ and $V_{i,calculated}$ respectively, then:

Any load shed during critical peak periods (CPPs) does not reappear after the CPP. Before explaining the rationale for that. the reader should revisit the description of the control philosophy described in section 6.2.1.3. Loads which are supplied with utility ripple receivers (e.g. hot water cylinders) do not qualify as controllable loads. They are controllable loads to the utility. but not to the DG owner! All loads shed by the utility do reappear in the model because the load data fed by the user in the load worksheet would consider the utility load shedding regime (any TOU meter/data logger fixed on the circuit containing the utility controlled loads will capture this).

As far as the model is concerned. controllable loads are those that can be switched off by the customer through deliberate personal intervention to take advantage of lines company price signals during CPPs. Even if CPPs do exist and customer sheds load. there is no benefit to the customer if the lines company does not base its tariff on CPP energy/capacity consumption (i.e. absence of price signals) and the retailer has not supplied a separate meter that registers energy/capacity drawn during CPPs. At present. such a meter is provided only for large industrial customers (typically > 250 kVA).

The load shed during CPP should not reappear in the following 2 cases.

- ☐ A case where the shed load is <u>transferred</u> to the controllable generator busbar as the generator (e.g. diesel gen set) would in any case be in operation during a CPP.
- ☐ A case where the user makes adjustments to the load matrix in the load worksheet to take into account the CPP load shedding by the customer. Since it is assumed that CPPs always occur at a fixed time (i.e. a fixed commencement time and a fixed ending time as explained in section 6.2.1.4) the user can easily shift the load shed to any other time outside the CPP. This should be

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$$\text{MAPE} = 100 * \sum_{i=1}^{i=n} \left| \frac{(V_{i,\text{actual}} - V_{i,\text{calculated}})}{n * V_{i,\text{actual}}} \right| \qquad \text{Eq. 6.4}$$

In the final leg of the calculation of customer load the simulated 17520 $P_{m,t}$ values are altered by removing the fraction of the load that is being shed during every half hour interval of every month. The final load of the customer (with load shedding) in a given day of a given half hour period on a given month would be;

$P_{m,t} - P_{m,t} * a_{m,t} * K_{m,t}$;

where $a_{m,t}$ is a dummy variable that would occupy either 1 or zero depending on whether the particular time period was a *critical peak period* or not. The time at which *critical peak periods* could occur is predetermined by the model in the form of an input variable (see data block (7) of Fig. 6.10). However the day is determined by a random process described in Appendix L. The calculation of final load is graphically presented[8] using symbols of matrix algebra in Table O.1 (Appendix-O).

6.2.2.2 Packaging load data of energy storage devices

The *load worksheet* does not synthesise load data of energy storage devices operating in *charge mode*. This data is synthesised in the *central worksheet*. The *load worksheet* borrows the load data of individual energy storage devices from the *central worksheet*, adds to the customer load to compute the total load on the 'load leg' of the DG system (explained in section 6.2.7) and forwards the data to the *final calculations worksheet*.[9]

6.2.3 The *wind worksheet*

The function of the wind worksheet is to forward two sets of half hourly wind data records in respect of two categories[10] of wind turbine generators (WTGs) to the *central worksheet*. The user may use either real data, which has to be manually inputted from a text file to the *wind worksheet*, or use archived data contained in the *wind worksheet* (Fig. 6.7). The data contained as an archive was synthesised[11] based on the following assumptions:

- annual average wind speed (at 10m height) = 6.0 m/s

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[8] *Note the sign convention used to handle the controllable load.*

[9] *This is a good example for the redundancy issue mentioned in section 6.2.*

[10] *The wind turbines categories are defined in section 6.2.7.1.*

[11] *Derived from the wind data generator of HOMER Pro v.1.58 software for RAPS design (NREL, 2002).*

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reflected in the load work sheet. For example if a 5 kW load is shed by the customer for one hour for 45 days (i.e. approx. 50% of winter days) in the winter during 38th and 39th half hour time intervals and the shed load is reconnected immediately after the end of the CPP (i.e. immediately after the end of the 39th time interval). the (mean) load data fed to the load worksheet for the 40th and 41st time interval has to be increased by 2.5 kW (i.e. 50% of 5 kW) to take into account reappearance of the shed load.

The first case (i.e. transferring the load to the diesel generator) was not included in the model algorithms. If the model is to be further improved. then the following two CPP scenarios may be added to overcome its current limitations.

- Option of transferring selected loads to a diesel generator.

- Occurrence of CPP during any time of the day for any duration. When the load is shed under this condition it is necessary for the model algorithms to take into account the reappearance of the shed load automatically after cessation of the CPP.

In the simulations of Totara Valley. no customer initiated load shedding was assumed and hence the accuracy of results (chapter 8) and conclusions drawn (chapter 9) are not affected by any limitations of the model on load control.

- autocorrelation factor = 0.8
- Weibull k = 2.0 (i.e. Rayleigh wind speed frequency distribution).[12]
- diurnal pattern strength = 0.1
- hour of peak wind speed = 3.00 pm to 4:00 pm

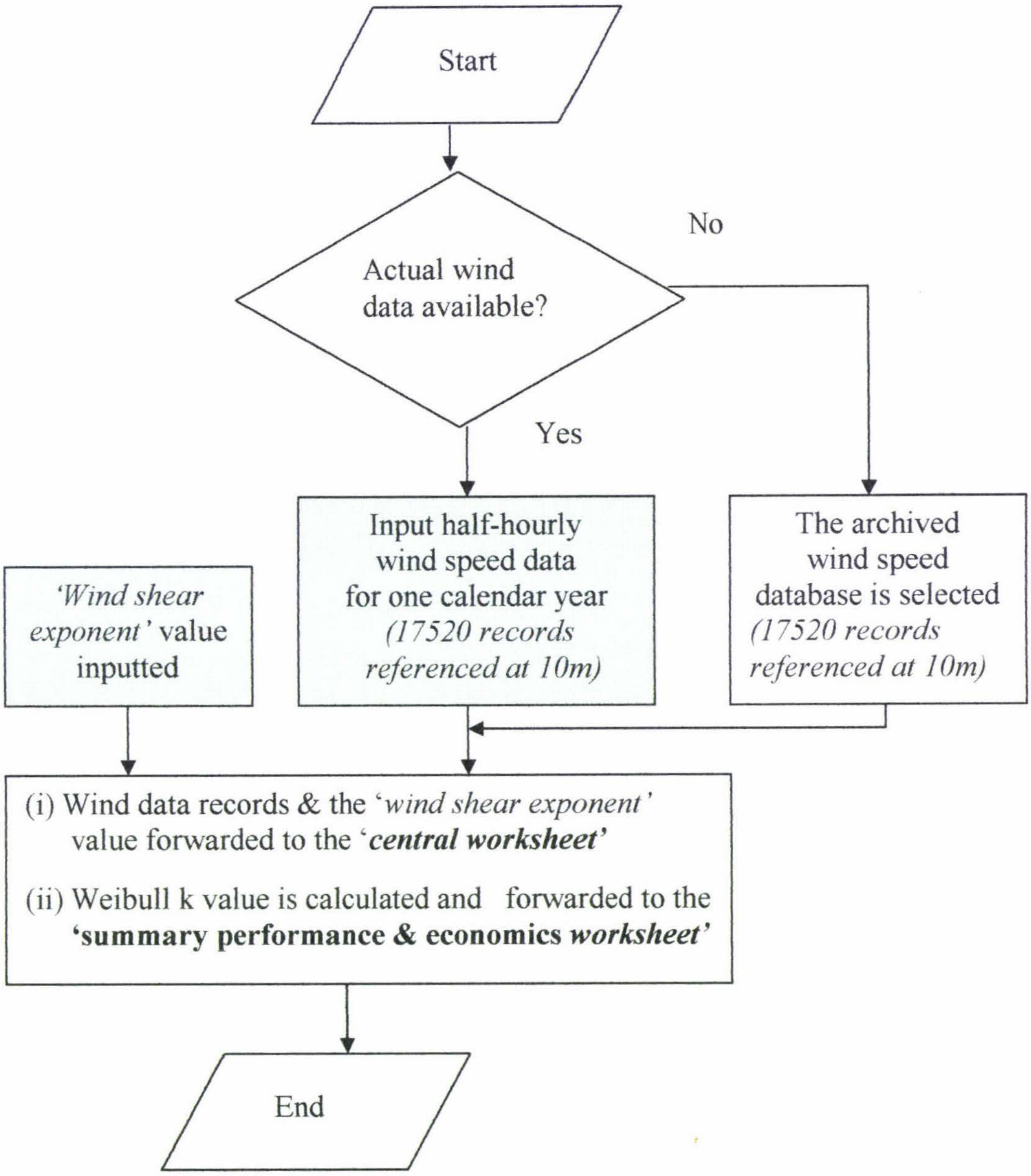

Fig. 6.7: The ***wind worksheet*** process flow chart in respect of a given category of wind turbine generators

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[12] *The Rayleigh wind speed frequency distribution and the hour of peak wind speed - 3.00pm to 4.00pm are the commonest among most wind regimes. The auto correlation factor and the diurnal pattern strength however depend greatly on the topography of a location. The autocorrelation factor (typical range: 0.80-0.95) is a statistical measure that describes the extent to which wind speed in one hour depends on the wind speeds of the previous hour while the diurnal pattern strength (typical range: 0.0-0.4) is a statistical measure that describes how strongly the wind speeds tend to depend on the time of the day. The statistical definition of the diurnal pattern strength is the ratio of the amplitude of the best fit cosine curve of hourly average wind speeds of the whole year to the annual average wind speed (NREL, 2002).*

If the user opts to choose archived data, the data records fed to the *central worksheet* would be rescaled to the annual average wind speed value inputted by the user.

The *wind worksheet* also calculates Weibull k value (for user information only) using Justus's algorithm (Justus, 1978 as cited by Manwell *et al*, 2002);

$$k = (\sigma_u/\bar{U})^{-1.086} \qquad \text{Eq. 6.5}$$

where;

σ_u is the standard deviation of the wind speed distribution over one calendar year.

$\bar{U}$ is the mean of the wind speed distribution over one calendar year.

The *wind worksheet* also forwards wind shear exponent values as inputs to the *central worksheet*.

6.2.4 The *solar worksheet*

The principal function of the solar worksheet is to transform manually inputted global horizontal irradiation data to data on the tilted surface of the PV array, and then forward

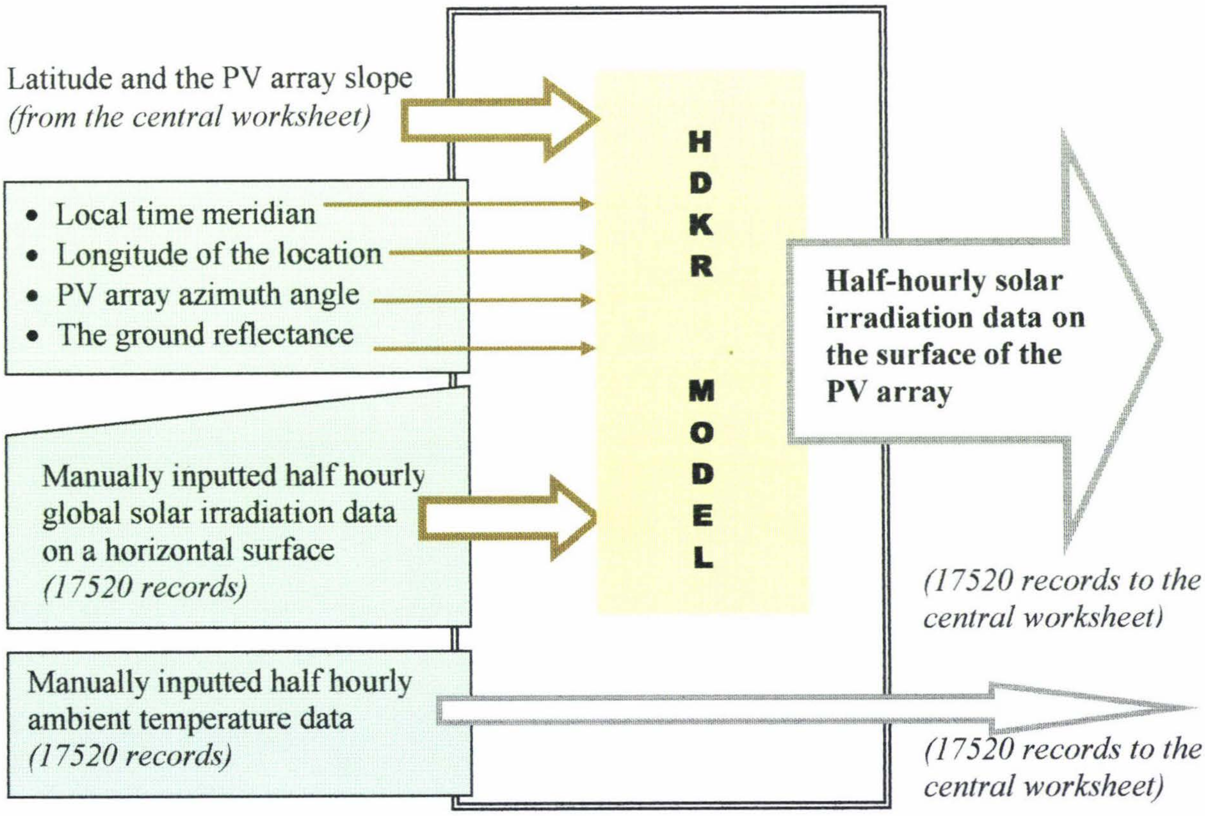

Fig. 6.8: The data processing at the *solar worksheet*

the same to the *central worksheet*. The data transformation uses the Hay Davies Klucher Reindel (HDKR) mathematical model that assumes a sky condition known as an *anisotropic sky* (Appendix – J). The HDKR model requires four other parameters (Fig. 6.8);

- local time meridian,
- longitude of the location,
- PV array azimuth angle and
- ground reflectance

The *solar worksheet* also accepts ambient temperature data, which is required by the central worksheet to calculate PV module output.

6.2.5 The *hydro worksheet*

The function of the hydro worksheet is to forward half-hourly water flow rate through the hydro turbine to the *central worksheet.* The model assumes that the average flow rate of a stream during a given week would be representative of the flow rate during any half hour of that week[13] (Fig. 6.9).

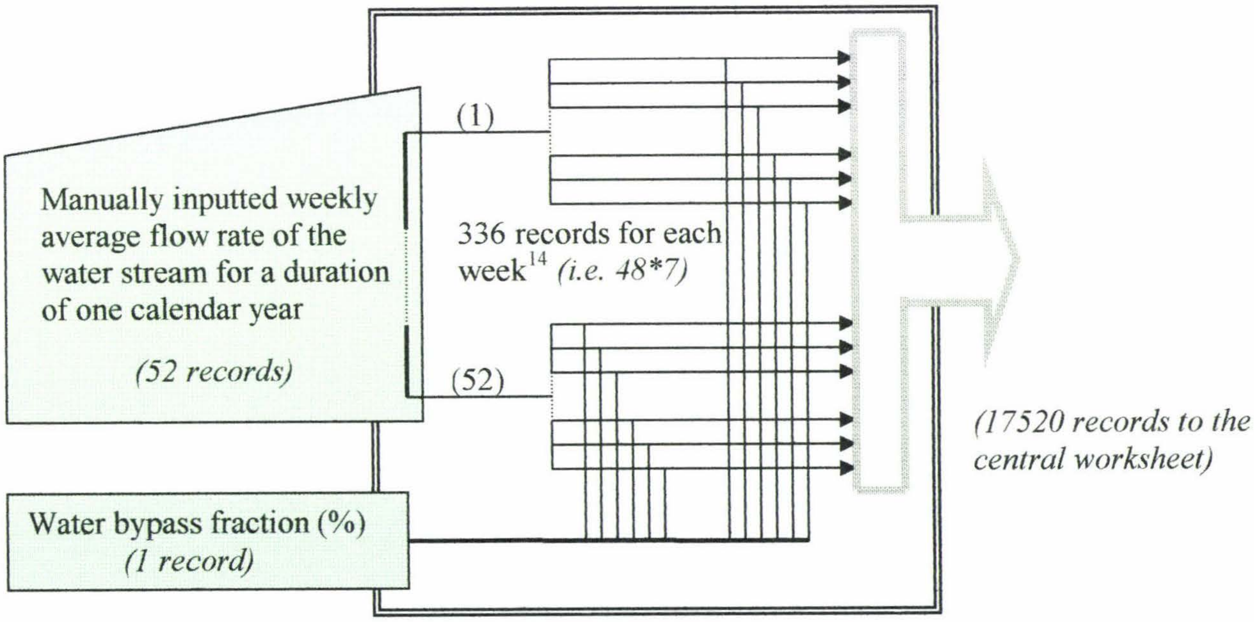

Fig. 6.9: The data processing at the *hydro worksheet*

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[13] *From a monitoring perspective, monitoring weekly flow data is always less costly than monitoring half-hourly flow data.*

[14] *The 52nd week is considered a 8 day week to constitute 365 days (from 52 weeks) and hence an additional 48 data records are required for this week.*

The model also assumes that a certain fixed percentage of water quantity needs to be bypassed from the turbine at all times in order to meet any resource consent requirement (if there is no resource consent requirement the user may input the bypass fraction as 0%).

6.2.6 The *electricity pricing worksheet*

The *electricity pricing worksheet* performs two types of data processing tasks. The first type of task it performs is the generation of data that are required (as input data) for other worksheets. This is achieved by building the necessary algorithms into the *electricity pricing worksheet*. The second type of task the worksheet performs is the acceptance of data (as input data) on behalf of the *central worksheet* and the *final calculations worksheet*. Fig. 6.10 illustrates the data processing tasks undertaken by the *electricity pricing worksheet* and the algorithms performed in the worksheet are covered in Appendix - K.

6.2.6.1 Assumptions and definitions

The following definitions and assumptions do apply in respect of data inputted to the *electricity pricing worksheet.*

- Sport price annual escalation rate: The spot price annual escalation rate (see input data block (2) in Fig. 6.10) is the rate at which energy spot prices escalate annually. The spot price of energy is assumed to be escalating at an annual rate of r% such that after n years from the commencement of the project, the spot price $C_{n,m,d,t}$ for the t^th^ half hour time interval of the d^th^ day of the m^th^ month shall be given by:

  $$C_{N,m,d,t} = C_{1,m,d,t} * (1+r)^{n-1} \qquad \text{Eq. 6.6}$$

  $C_{1,m,d,t}$ is the spot price for the first year, generated by an algorithm written into the worksheet. By default, the model assumes that the DG owner and the incumbent retailer have agreed on energy prices based on spot prices. However if an energy supply contract is based on time of use (TOU) pre-agreed prices plus line charges, this could be handled by substituting the Haywards grid exit point (GXP) spot prices with the contractual prices and setting the daily and hourly noise parameters to zero, in the *load worksheet*.

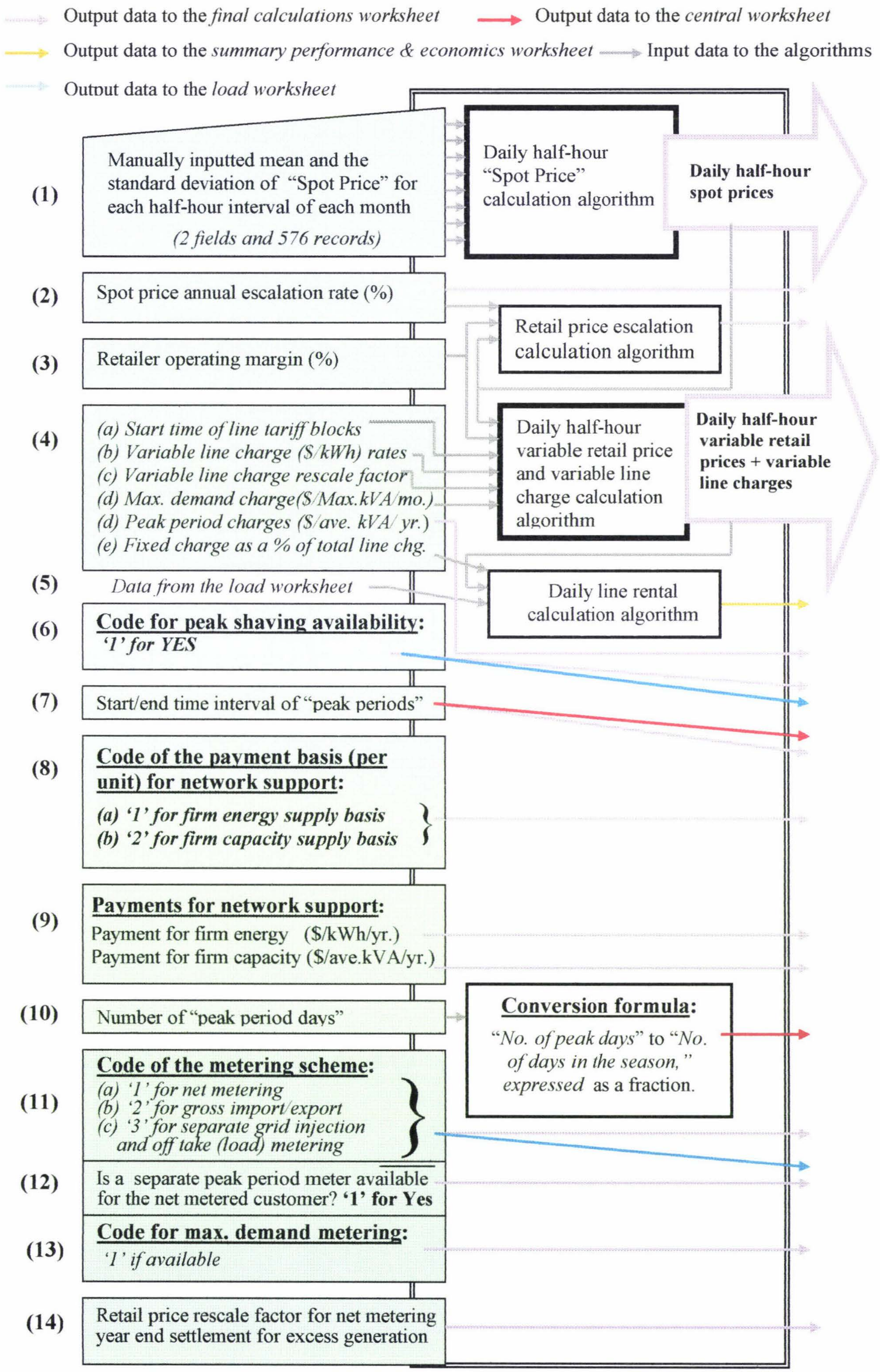

Fig. 6.10: The data processing at the *electricity pricing worksheet*

- Retailer operating margin: Retailer operating margin (input data block (3) in Fig. 6.10) is the gross profit margin a retailer expects on energy sales based on spot prices.

- Start times of tariff blocks: These refer to the half hour time interval in which a particular line tariff block commences. In New Zealand, typically, only two tariff blocks exist: the day and night tariffs. The actual start and end times of the two tariff blocks differ from lines company to lines company. The model divides a day into six four-hour time blocks, with the first block commencing at the beginning of the seventh half hour period of the day, 3:30 am.[15]

- Variable charge rates: The variable charge rates (input data block (4) (c) in Fig. 6.10), refer to $/kWh rates imposed by a lines company for its each tariff block. In New Zealand, all line companies charge the customers based on energy referenced to the GXP (& not the customer's actual meter reading). The energy referenced to the GXP shall be the actual energy consumption of the customer plus the total energy loss that is deemed to have occurred when energy is conveyed from the GXP to the customer's energy meter. Therefore, in feeding input data on variable line charges, the user should multiply the charge rates stipulated by the lines company by the corresponding *loss factors*, if available.[16,17]

- Line charge rescale factor: This allows the user to begin the analysis based on the existing line tariffs and perform a sensitivity analysis by rescaling the variable charge rates without adjusting the original variable charge rates for the six tariff blocks.

---

15. *Since the first block commences at 3:30 am and there are six four-hour tariff blocks, the sixth block will commence at 11:00 pm and continue up until 3:30 am the following day. Since electricity is a very price inelastic commodity, in general, a lines company cannot use differential tariffs as a vehicle to lower the peak load. Arguably, this is why only two tariff blocks exist in New Zealand and that technology options are preferred over tariff-induced options for peak shaving.*

16. *An energy retailer makes a similar adjustment in apportioning customer line charges.*

17. *The loss factor (LF) is mathematically defined as LF = 1/(1-LR); where LR (loss ratio) is the proportion of the total energy loss between the GXP and the customer metering point. LF will typically depend on the type of the customer, time of the day (e.g. day time Vs night time), the time of the year (e.g. high load seasons of Winter and Spring Vs low load seasons of Summer and Autumn), the area or zone to which a customer belongs (e.g. rural Vs urban). If a line company stipulates its LF (or LR) based on the season (among other things), the user will have to calculate the annual average LF as the model does not have a provision to accommodate line tariffs based on the season.*

- Number of "critical peak days": In dealing with critical peak days, it is assumed that there is only one *critical peak period* per day and that *critical peak periods* could either occur in one season only or if they occur in more than one season, the *number of critical peak days are equal for all the seasons (in which critical* peak periods occur). It is also assumed that the occurrence of a *critical peak period* in a given day is a "quasi random event" in that there is an equal chance of any day of a critical peak season to be a critical peak day. However, the model assumes that *critical peak periods* start and end at the same time every time it occurs in any given season (Appendix – L).

- Code of the metering scheme: The model can simulate any one of the three metering systems described in Table 6.3, each being identified with a specific single digit code.

Metering System/Code	**Metering/billing description**
"Net metering" (Code ≡ 1)	A net metering system (Fig. 6.11) where any excess generation (kWh) is carried forward from one month to the next month from January through December (no monthly dollar credits) and finally if there is any year end excess generation left at the end of December, the customer is credited a sum: Credit (\$) = (Excess generation as on end December)*(average half hour retail price)*(retail price rescale factor) As the model works on spot prices and line tariffs, which are real time quantities, the retail price was assumed to be the annual average half hour retail price. [18]
"Gross import/ gross export" (Code ≡ 2)	Electronic TOU meter that records half hour gross import and export energy flows (Fig. 6.12). In addition, separate energy meters may be present to measure critical peak period export, import and the maximum demand (depending on the lines company pricing policy on off takes and injects).
Separate generation and load metering (Code ≡ 3)	Electronic TOU meter that records half hour energy flow from the DG system to the grid. Additional meters similar to gross import gross export metering may be present (Fig. 6.13).

Table 6.3: The metering and billing scenarios simulated by the model

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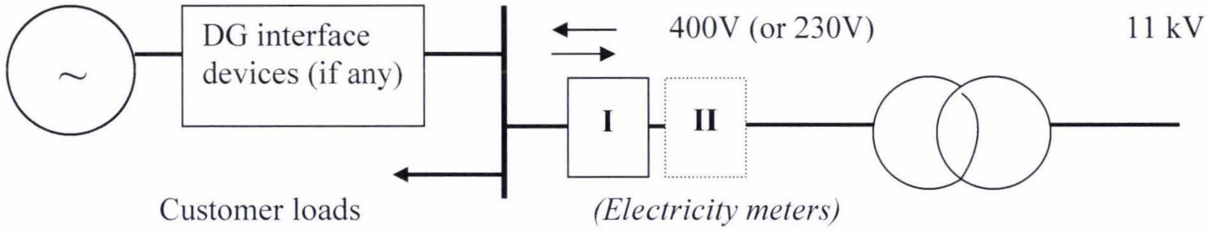
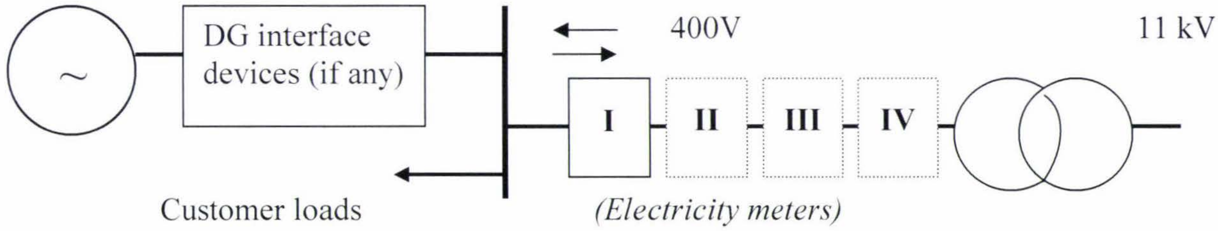
18. *The "retail price rescale factor" reflects the value the energy retailer palaces on "anytime energy generated". It is reasonable to assume that an energy retailer would credit a customer for excess energy at a rate equal to (or slightly lower than) the average spot price of the billing year. If it cannot be determined from the information provided by the retailer it could be assumed that the retail price rescale factor is equal to the average spot price divided by average retail price*



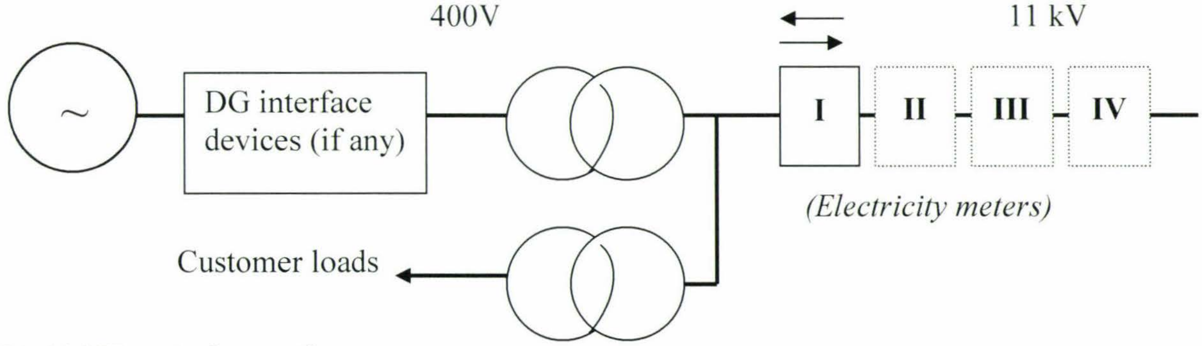
I - Conventional induction disc type energy meter (bi-directional) or two separate Conventional induction disc type energy meters measuring forward and reverse energy flows.

II – Ripple activated critical peak period export energy meter (not normally expected to be available even under critical peak period pricing)

Fig. 6.11: Net metering arrangement



(a) Low voltage metering option



(b) 11 kV metering option

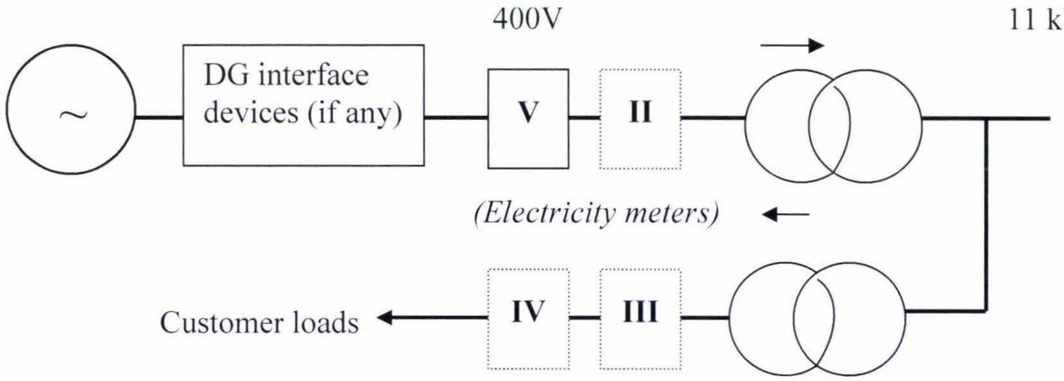
I - Electronic dual element TOU import export energy meter

II – Ripple activated *critical peak period* export energy meter (if applicable)

III – Ripple activated *critical peak period* import energy meter (if applicable)

IV - Maximum demand meter (if applicable)

Fig. 6.12: Gross import/gross export metering arrangement



V - Electronic TOU export energy meter
II – Ripple activated critical peak period export energy meter (if applicable)
III – Ripple activated critical peak period import energy meter (if applicable)
IV - Maximum demand meter (if applicable)[19]

Fig. 6.13: Separate generation (and load) metering arrangement

As regards to the net metering arrangement (Fig. 6.11), if a lines company is basing its product on *critical peak period* load (as defined in section 6.2.1.3) and if net-metered customers and "gross import/gross export" customers need to be credited for the reduction of load (or total elimination of load) during *critical peak periods*, a conventional ripple activated second energy meter (during *critical peak periods*) may be installed. If an induction disc type meter is used, it has to be detented to prevent spinning backwards when generating more than the load. This study examines the value of a second meter, both to the customer as well as to a lines company.

In "gross import/gross export metering" and "separate generation and load metering" arrangements, it is assumed that electronic TOU meters are in place to account for energy based on the spot prices as well as that component of the line charges which is based on kWh consumed depending on time of day (usually day consumption and night consumption). However to credit customers for firm capacity (or firm energy) an additional ripple controlled meter is required to record the quantity injected during the *critical peak period* (Fig. 6.12 and 6.13). If customers are charged for maximum demand, then a maximum demand meter should also be included in the metering mix. However, since the customer has no knowledge of the time of occurrence of the maximum demand, the model assumes that no customer induced load shedding takes place when the demand rises to high levels, in order to reduce the maximum demand.

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[19] *The standard anytime and controlled energy meters on the customer loads are not shown as they are not a part of the DG system.*

The central worksheet (page 136) and in fact the whole model is based on a "systems approach." Hence it is valid at an individual farm level as well as a community level as long as the DG system can be identified as a physical system (section 6.1.1). For example if a community owns a 250 kW wind turbine generator and the generation is directly interfaced to the grid, that system is similar to one shown in Fig. 6.3 (page 113).

By including different electricity metering schemes and DG platforms, the author has attempted to accommodate as many physical systems as possible (valid at individual as well as community levels).

6.2.7 The *central worksheet*

The primary function of the *central worksheet* is to generate energy/load flows at the network interface point and forward the energy/load flow data as well as the relevant DG data to the *final worksheet* for analysis.

Irrespective of the actual metering arrangement, the *central worksheet* assumes that three hypothetical energy meters exist; one each at the grid leg (gross import/export energy metering), the load leg and the customer leg (Fig. 6.14). Note that the configuration holds good for both low voltage and 11 kV metering schemes (Figs. 6.12 and 6.13) if transformer losses are ignored. Based on the data inputted to the worksheet and the data imported from other worksheets (Fig. 6.14), the *central worksheet* calculates the energy flows[20] through the three energy meters during each half hour.

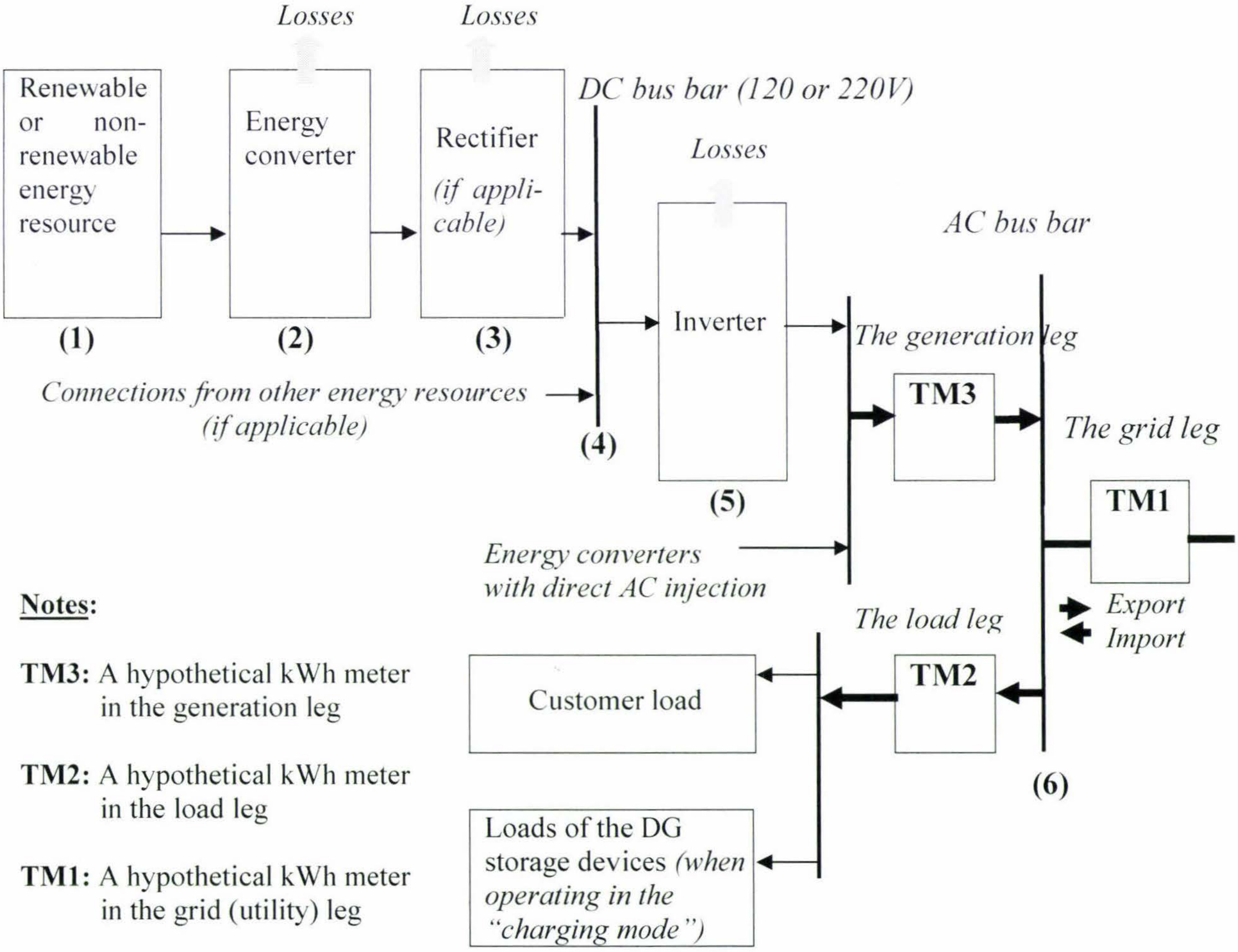

Fig. 6.14: The load flow path used for the algorithms in the *central worksheet*

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[20] *Since input output characteristics of DG systems and associated hardware are referred to in "power" (e.g. WTG power Vs wind speed; inverter efficiency Vs AC output power) and that average power is proportional to "energy" (energy in kWh = half hour average power in kW*0.5), it is easier to deal with average power than with energy. Hence, in the worksheet, data fields of TM3 and TM2 are recorded in kW (average power). The data field of TM1 is recorded in kWh using the following formula and sign convention:*

*TM1 = (0.5*TM2 – 0.5*TM3) If TM1 >0 it is "energy import" and if TM1<0 it is "energy export"*

The *central worksheet* acts as the hub in the overall data processing. To process data, the user needs to input certain data on DG system and the investor's cost of capital and the risk premium. The worksheet then processes the inputted data along with data imported from other worksheets (Fig. 6.15).

6.2.7.1 Inputting data

The model can simulate an individual or a hybrid system consisting of the following distributed resources.

- **Any number of small (<50 kW) wind turbine generators (WTGs):** Among other data, the user needs to input the technology used for interconnecting the WTG to the grid. If paralleled through power conditioning equipment (i.e. rectifiers and inverters) it should be coded as "1" while if direct (i.e. synchronous generators or induction generators) it should be coded as "2".

- **Any number of medium to utility scale WTG ($\geqslant$ 50 kW):** The technology codes are not required as the model assumes that the WTGs shall invariably be directly interconnected.

- **One PV array of any capacity:** The user needs to define the peak array capacity in terms of the number of equivalent 50Wp modules.[21]

- **One micro hydro unit:** The model assumes that the technology used for interconnecting a micro hydro unit with the grid shall involve power-conditioning equipment except in the case of low cost micro hydro. Since a low cost micro hydro involves an induction generator, the model assumes a direct interconnection.[22]

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21. *In strict technical sense, the PV array capacity could only be incremented by adding more parallel strings of PV modules. Depending on the capacity, the inverter DC side voltage will be either 120V or 240V (approx.). On the other hand, the voltage difference across a PV module at maximum power point would be approximately 12V. Therefore, to increase capacity, one needs to add either 10 or 20 modules together, which means the PV array capacity could only be incremented in either 500W steps or 1000W steps.*

22. *The turbine code (1 for Pelton wheel, 2 for Cross flow, 3 for low cost reverse engineered pump) needs to be inputted for proper identification of the technology used (which in turn determines the interface devices required) and for forecasting the costs at the final calculation worksheet.*

Maintenance costs do not appear in Fig. 6.15 but appear in Fig. 6.16 in the form of an intermediate input, as shown in label (37) in Fig. 6.15 and Table 6.5. The model predicts annual costs that include operation and maintenance costs (see Appendix M for details).

Fig. 6.15 is not the appropriate location to depict maintenance costs because the primary function of the central work sheet is "energy and load flow reconciliation", as mentioned in paragraph one in section 6.2.7 of page 136.

The only cost inputted by the user in the central work sheet is the cost of fuel. The author views "fuel" as an energy source. Given the type of fuel (hence a fixed kJ/kg heat value), assuming other things being unchanged (e.g. diesel gen set capacity) the only decision variable pertaining to fuel is its retail cost.

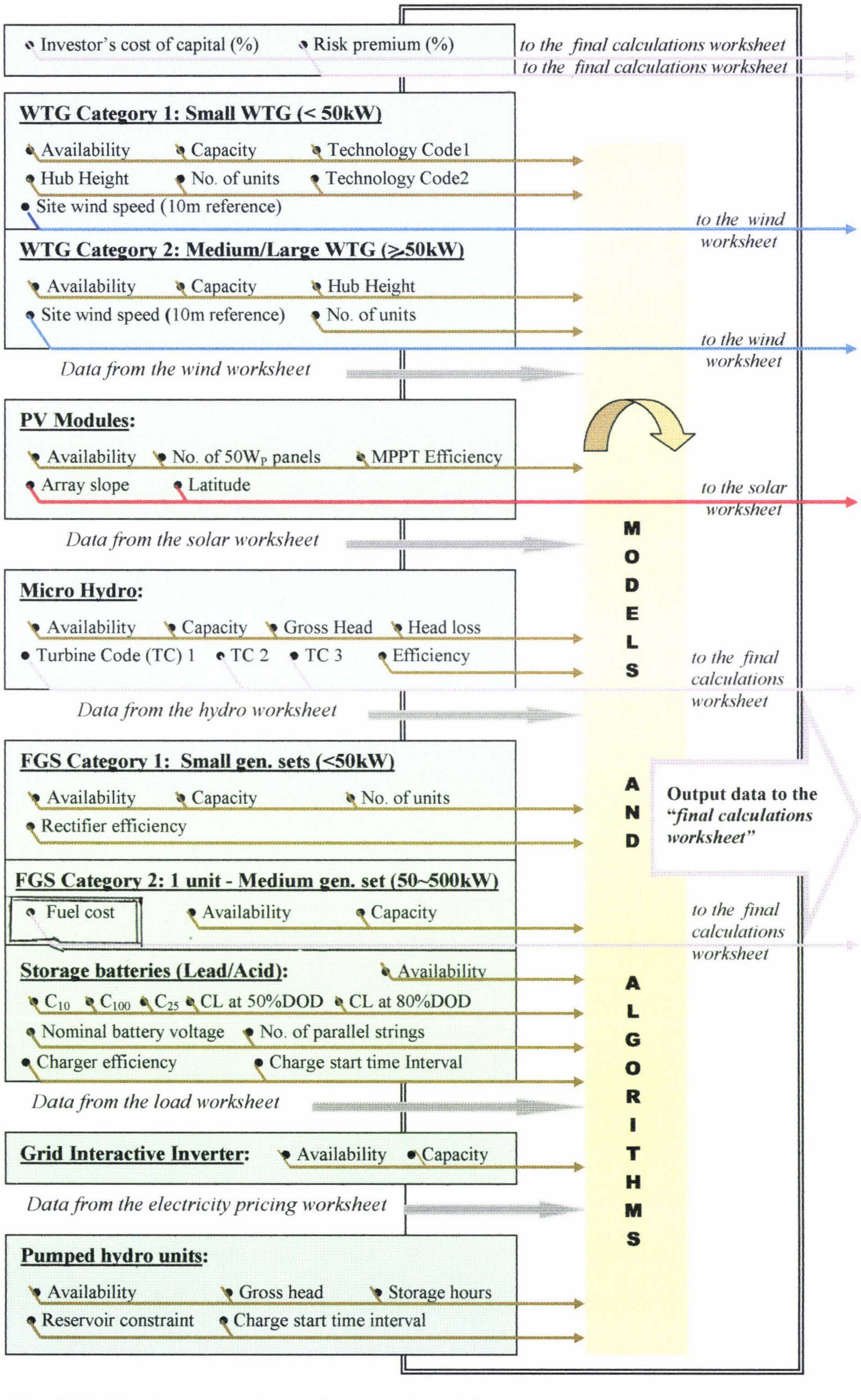

Fig. 6.15: The data processing at the *central worksheet*

- **Any number of small (<50 kW) fuelled generator sets (FGSs).** The model assumes that small FGSs shall always be interconnected through power interface devices (i.e. rectifiers and inverters).

- **One medium (50~500 kW) FGS.** The model assumes that a medium FGS shall be interconnected directly.[23]

- **One battery bank.** Only deep cycle lead/acid batteries could be simulated since the built-in algorithms on battery charging, discharging and cost prediction are valid only for lead/acid technology.

- **One pumped hydro unit**. The model assumes that low cost pumped hydro technology is used. Accordingly, the water pump load is that of an inductor motor while the energy injection when operating in the turbine mode shall be direct AC injection because an induction motor is operating as an induction generator.

6.2.7.2 The data processing

In order to output data referred to in section 6.2.7.3, several data processing tasks are undertaken (Appendix – L). A summary of the key data processing tasks undertaken are described below.

- Identification of all physical hardware (i.e. DGs and buffering equipment such as rectifiers and inverters) available.

- Assembly of physical hardware as per the technologies inputted (e.g. a medium scale wind turbine to bypass the inverter).

- Calculations of wind/solar/hydro energy production from the energy resource up to the utility interface point, using in-built input/output functional relationships of the physical hardware involved (Fig. 6.14). The input/output functional relationships have been derived using regression techniques (OLS method) using publically available data such as power curves and efficiency curves.[24]

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[23] *See section 3.5.1. for problems on synchronising small to medium FGSs.*

[24] *Since there are wide varieties of physical hardware with different capacities in the market (e.g. WTG) the parameters (e.g. wind turbine power output) are normalised before the regression equations are applied.*

- Determination of *critical peak period* days of the calendar (a random process) and dispatch of FGSs/pumped hydro/batteries to the grid during *critical peak periods*.

- Determination of the duration of operation of charge loads in respect of DG storage devices.

Apart from the above five data fields, capacity data and hardware availability data are also forwarded to the final calculations worksheet in the form of raw data for forecasting project costs.

6.2.7.3 Output data

The following four data fields (each field containing 17520 records) are outputted to the final calculations worksheet:

1. Average power flow through the generation leg, each half hour (i.e. TM3 reading in Fig. 6.14).

2. Energy flow through the grid leg as recorded by the "import energy meter" each half hour.

3. Energy flow through the grid leg as recorded by the "export energy meter" each half hour.

4. Average power flow through the load leg, each half hour (i.e. TM2 reading in Fig. 6.14).

6.2.8 The *final calculations worksheet*

The primary function of the *final calculations worksheet* is to calculate the DG investment appraisal results and to calculate the foregone revenue to the relevant lines company.

In general, all renewable energy units will last at least 20 years (with proper maintenance). The lifetime of batteries and diesel generators among other things will depend on the duty cycle.

As an example say if a diesel generator is used for winter peak lopping during critical peak periods and critical peak periods do occur on all the 92 days in the winter and that each spell of critical peak period lasts 1 hour, then the diesel generator would have operated for only 92 hours for the whole year. Therefore, there is no need to replace the diesel engine during a 20-year project life cycle.

A deep cycle lead acid battery discharged to a decent depth of say 40%, can last about 3000 cycles (Fig. 3.16). Since critical peak periods last only for 92 days a year and batteries are cycled only once a day for 92 days, at least mathematically, the batteries should last for 32 years! (being 3000 ÷92). Therefore, there is no need to replace the batteries during a 20-year project life cycle.

For the above reasons simple operation and maintenance cost prediction algorithms have been used for diesel engines, batteries and pumped hydro systems.

If for whatever reason the above controllable generation sources have to be used regularly (such as being used in remote area power system environments), more sophisticated algorithms will be necessary and there should be flexibility to change the duration of the project's life (say from 20 years to 25 years) taking into account the duty cycles of the controllable sources.

6.2.8.1 DG project investment appraisal

Under project investment appraisal, the *final calculations worksheet* outputs the following indicators of financial viability:

- Payback.
- Accounting rate of return (ARR).
- Net present value (NPV).
- Internal rate of return (IRR).
- Profitability index (PI).
- Net present cost (NPC).

The following assumptions were made for the algorithms when used for calculating the above indicators.[25]

- The life time of a DG project is 20 years.
- The rate of inflation is negligible.
- The cash inflows during the life cycle of the project are caused only due to the sale of energy (kWh) to the retailer, avoiding purchase of energy from the retailer (this does not apply to the *separate generation metering scheme*); supply of firm capacity or firm energy to the lines company (if *critical peak period* pricing exists); and resale of project assets at the end of the project life cycle. Accordingly, it follows that there are no government grants, tax receipts and that there are no other cash inflows caused by virtue of accepting the project.[26]
- The cash outflows during the life cycle of the project are caused by the initial investment of project planning, procurement, installation and commissioning plus annual operation and maintenance (O&M) costs of plant and equipment and monthly

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[25] *It is important to note the difference between an financial performance appraisal and an economic performance appraisal of a renewable energy project. The approach covered by the model is a financial performance appraisal which analyses a DG project from the investor's perspective and not from the point of view of the economy of a country. An economic performance appraisal on the other hand looks at viability from a governmental viewpoint, seeking to compare the value to the economy as a whole, over a long time scale. The costs and benefits relevant to economic analysis will be different from those relevant to accounting analysis. For example under economic analysis, the costs and benefits must be used that are free from taxes, subsidies, interest payments and so on (Barlow, 1997).*

[26] *The model ignores income tax because of the complexity of calculating the same.*

payments to the lines company for grid injection (if charged). Accordingly, it follows that there are no tax payments or any other cash outflows caused by virtue of accepting the project.

- There are no forced outages of plant and equipment and there are no capital acquisitions during the course of the project life cycle other than initial capital acquisition.

- The lines company is indifferent to the power factor at which the active power is injected to the grid as long as it is not "leading power factor".[27]

6.2.8.2 Foregone revenue to the lines company

Under foregone revenue to the lines company, the *final calculations worksheet* outputs the foregone revenue on account of lowered energy delivery and lowered *critical peak period* load and the lowered maximum demand[28] due to DG after taking into account any returns from charging the customer for grid injection. Payments made to DG owners for network support is not considered a "foregone revenue" as it is the opportunity cost of capacity expansion to the lines company.

6.2.8.3 Algorithms used

All algorithms used in the *final calculations worksheet* are shown in mathematical format (Appendix M). Fig. 6.16 depicts the graphical presentation of the data processing involved in the worksheet while Tables 6.4 and 6.5 depict the data used for computation of the project accounting performance indicators and the foregone lines company revenue.

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[27] It is assumed that *DG interfaced through an inverter will not operate at leading power factors due to the manner in which the inverter is designed. DG involving induction generators, which are invariably coupled directly to the grid, will generate active power but will supply it at a leading power factor. The practical implication of this is that any technology involving induction generators will have to have capacitors paralleled to the generator (and hence the additional cost) to compensate for reactive power drawn from the grid to magnetise the stator core of the generator. However Orion NZ Ltd. use four quadrant metering for large DG customers to capture energy import/export and reactive power import/export and pay the DG owner based on both active and reactive power flows. From the energy retailer's view point, for payments for energy inject, it does not matter which power factor the DG operates at a given time as long as distribution losses are not assumed to be affected.*

Four quadrants are used in electrical engineering to denote real power import (- x axis), real power export (+ x axis), reactive power import (- imaginary y axis) and reactive power export (+ imaginary y axis). Note that the reactive power is denoted in an imaginary y axis.

[28] *Not applicable to all the metering schemes.*

Input data label	Description	Data source
(1)	Average power flow through the generation leg, each half hour (i.e. TM3 reading in Fig. 6.11).	*Central worksheet*
(2)	Energy flow through the grid leg as recorded by the "import energy meter" each half hour (i.e. import meter reading of TM1 Fig. 6.11).	*Central worksheet*
(3)	Energy flow through the grid leg as recorded by the "export energy meter" each half hour (i.e. export meter reading of TM1 Fig. 6.11).	*Central worksheet*
(4)	Average power flow through the load leg, each half hour (i.e. TM2 reading in Fig. 6.11).	*Central worksheet*
(5)	The code of the metering scheme.	*Electricity pricing worksheet*
(6)	Daily half hour spot prices for electrical energy.	*Electricity pricing worksheet*
(7)	Daily half hour variable retail prices.	*Electricity pricing worksheet*
(8)	Days in which critical peaks occur.	*Electricity pricing worksheet*
(9)	Time interval in which critical load peaks occur	*Electricity pricing worksheet*
(10)	Spot price escalation rate	*Electricity pricing worksheet*
(11)	Retail price escalation rate	*Electricity pricing worksheet*
(12)	Retail price rescale factor (for "Net metering")	
(13)	Basis of payment for network support (i.e. firm capacity or firm energy?).	*Electricity pricing worksheet*
(14)	Rates of payment for firm energy/capacity	*Electricity pricing worksheet*
(15)	Peak shaving availably code (1 = Yes, 2 = No)	*Electricity pricing worksheet*
(16)	Controllable load each half hour	*Loads worksheet*
(17)	Critical peak period price of energy ($/kWh)	*Electricity pricing worksheet*
(18)	Average load of DG storage devices, in energy charging mode, during each half hour interval.	*Loads worksheet*
(19)	DG availability information (1 = Yes, 2 = No)	*Central worksheet*
(20)	DG quantities available (incl. inverter)	*Central worksheet*

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Input data label	**Description**	**Data source**
(21)	DG capacities connected	*Central worksheet*
(22)	Relevant DG technologies (code no.)	*Central worksheet*
(23)	Fuel cost	*Central worksheet*
(24)	Annual charges for grid injection	Manually inputted directly
(25)	Percentage capital provided as a soft loan	Manually inputted directly
(26)	Annual interest rate for the soft loan	Manually inputted directly
(27)	Investor's cost of capital and the risk premium	*Central worksheet*
(28)	Salvage value of plant and equipment	Manually inputted directly
(29)	Variable line charge data (i.e. half hourly $/kWh line tariff component)	*Electricity pricing worksheet*
(30)	Portion of the initial cost provided by the state as a low interest loan and the interest charged	Manually inputted directly

Table 6.4: Input data to the *final calculations worksheet*

Input data label	**Description**
(31)	Half hourly energy flows through the interface between the DG and the grid.
(32)	Cash inflows from sale of electricity to the retailer.
(33)	Cash inflows due to avoiding purchase of electricity from the retailer.
(34)	Cash inflows resulting from payments (or credits) for supply of firm capacity or firm energy to the network.
(35)	Cash inflows resulting from avoiding *critical peak period charges* due to reduction of energy drawn from the grid due to generation and/or load shedding initiated by the DG owner.
(36)	Initial project cost of different items.
(37)	Annual costs of different project items.

Table 6.5: Derived data used for the accounting performance indicators of the project

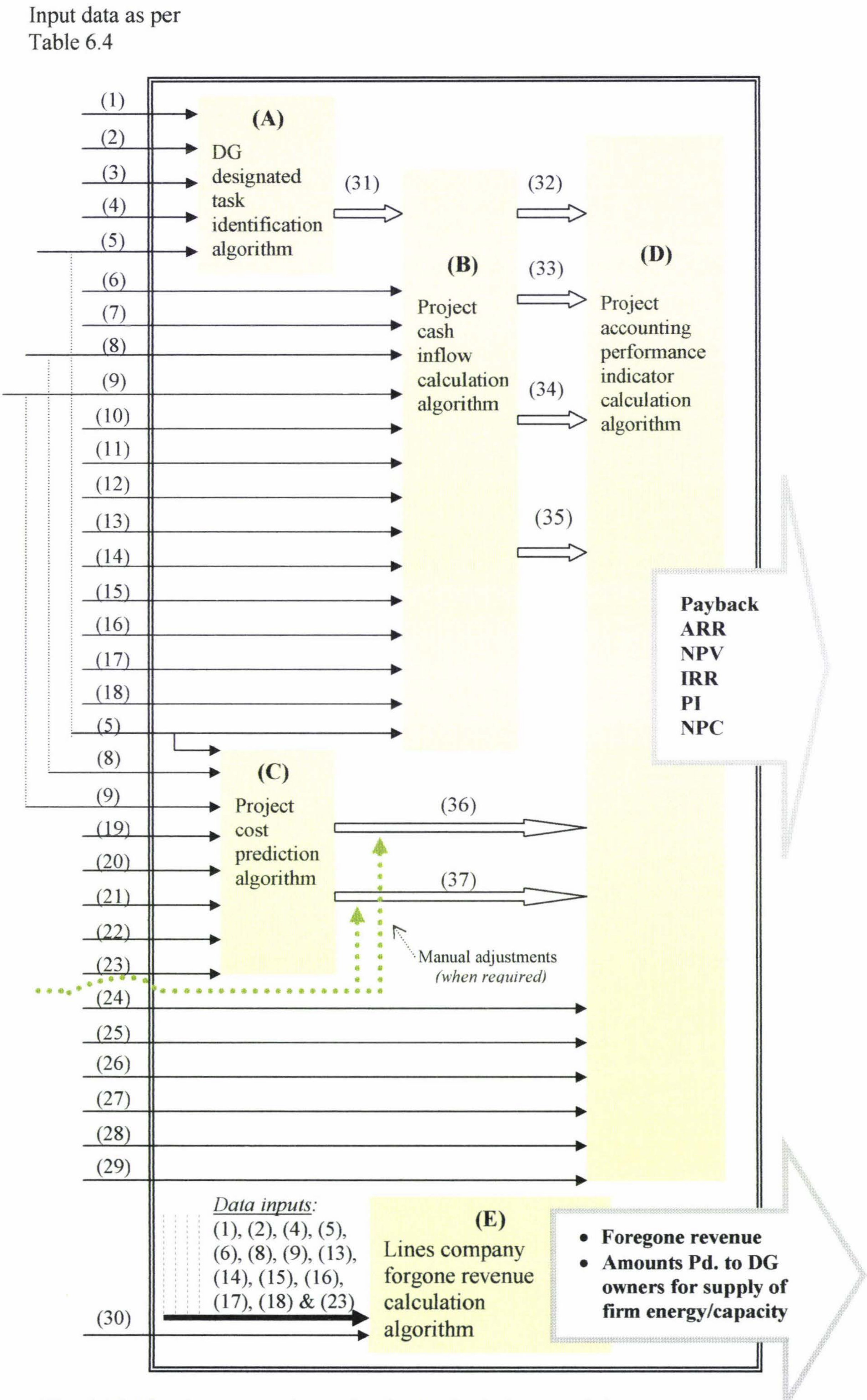

Fig. 6.16: The data processing at the *final calculations worksheet*

The project cost prediction algorithm (block (C) of Fig. 6.16) was constructed using publically available ex-factory prices of different DG components as quoted by different manufacturers as well as cost guide lines given by research organizations such as NRCan/CANMET (2002) in connection with planning, installation, commissioning, operation and maintenance of grid connected DG projects. The standard approach used in this regard was to forecast the initial cost of the key component costs from publically available cost data and then fit polynomial regression equations with cost as the dependant variable and the subsystem capacity as the independent variable. Based on the costs of key components the algorithms then peg the initial costs of other cost components as a linear function of the key component/s using cost guide lines given by research organizations for planning, installation, commissioning, operation and maintenance of grid connected DG projects (section M.4 of Appendix M). Although every effort was made to collect sufficient data to make sure that the regression equations fitted for key project items shall be adequately representative of actual costs, it was not always possible to achieve this objective. For example in respect of diesel generator sets, cost data were available from 7 sources, but for inverters above 10 kW capacity, only one data source was available. The user can use his or her personal knowledge and change one or more variables to accurately represent any given situation.

Among other things the above algorithm assumes a new installation in entirety (Appendix M), which may not always be the case. For example, supposing if one wishes to investigate how economical for an industrial organization, which already possesses a 250 kVA diesel standby generator (and hence its capital of the plant and buildings has been paid for), to operate its standby generator, the software user will have to force the predicted variables "plant cost" and "other costs" to zero and adjust the "installation cost" to include only the procurement and installation cost of the synchronizing equipment.

6.2.9 The *summary performance and economics worksheet*

The *summary performance and economics worksheet* does not perform any data processing. It simply draws data from other worksheets to package a three page summary report on the project. Since all key project output data are listed in the worksheet, the user can change an input variable at any other worksheet and quickly observe the impact of it on key project output variables listed in the *summary performance and economics worksheet*. Accordingly this worksheet forms an ideal platform to conduct sensitivity analysis.

6.3 APPLICATION OF THE MODEL TO "TOTARA VALLEY"

6.3.1 Filling of input data gaps

The monitoring of Totara Valley data were undertaken for six months only (01 March 2003 through 31 August 2003) and no hydro flows and wind flows were monitored during this study. The data gaps were filled as follows:

- Solar irradiation data: Hourly global solar irradiation data of the Kelburn meteorological station in Wellington as reported by Duffie and Beckman (1997) were inputted for the 6 months for which actual data were not available.

- Ambient temperature data: It was assumed that an approximately symmetrical (half hour average) temperature profile exists on either side of 16 July (being the median day of winter) and hence September, October and November temperatures were assumed be having one to one correspondence for every half hour with May, April and March temperatures respectively. The temperatures of December, January and February were assumed to be 10% higher than the corresponding March temperatures.[29]

- Hydro inflow and head data: Hydro flow data of the Totara stream, collected by Irving (2000) from 31 December 1998 to 12 August 1999 were used. The missing data from mid August to end December were filled assuming that the flow rate of stream between the said interval is constant and shall be the average of 31st December 1998 flow reading and the 12th August 1999 flow reading. The total head of the ideal location was taken as 13.5 m, as reported by the above researcher.

- Wind speed data: According to Irving (2000), the annual average wind speed at Farm A (700m from the main farmhouse) is only 5.4 m/s. Although no published data were available, on observation of sample data collected by Murray (2002) for his on going doctoral research, sufficient background data were obtained to

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[29] *The ambient temperature data are required to convert the PV module power output at reference cell temperature to actual cell temperature. The reference cell used is the normal operating cell temperature (NOCT). The actual cell temperatures would be different from the NOCT (which is 47^0C approx. for Solarex MSX - 50 modules, being the temperature solar cells would reach when the module is exposed to a 800 W/m2 irradiation at 20^0C ambient temperature and at 1m/s wind speed) chiefly due to different ambient and solar irradiation conditions. However, the temperature coefficient of module power is small compared to unity. Hence, it is not necessary to have very accurate temperature data.*

synthesise wind data. In particular, it was observed that a 6.0 m/s site exists in Farm B (about 800m from the main farmhouse) having a windiest half hour between 3:00 pm to 3:30 pm (overall) with an autocorrelation factor of 0.8 (considering the complex terrain). In addition, it was assumed that a Rayleigh wind speed frequency distribution exists with a diurnal pattern strength of 0.1. As mentioned in section 6.2.3 these data were used to synthesise half-hourly wind speed data in the *wind worksheet* using the RAPS design program HOMER Pro version 1.58 (NREL, 2002).[30]

- Load data: The monthly means and standard deviations for each half hour for the missing six months were estimated from load research results published by IRL (2002). The estimation procedure is depicted in section N.1 of Appendix N (also see Fig. 7.14 and 7.15). Appendix – N also depicts how load data of Zones B and C were estimated from Zone A data.

- Topographical data required for pumped hydro systems: No field surveys were undertaken. However on referring to Palmerston North topographical maps as well as site visit it was estimated that the topography allows a pumped hydro system with two reservoirs with total storage 200m^3 each (including a 20% dead storage) at head difference of 60m. It was also assumed that the pump/turbine capacities should be such that the reservoirs shall be depleted if the units run more than 90 minutes.

6.3.2 DG combinations and metering schemes considered

6.3.2.1 Zone A (i.e. a single farm application on Totara road)

The following systems were simulated once each for "net metering" and "gross import/ gross export" metering schemes (Fig. 6.11 and 6.12 (a)) under existing network loading levels as well as a hypothetical network loading of country feeder being overloaded in winter on certain days for 60 minutes during the 36th and 37th time interval, for which ScanPower is offering $ 120.0 per kW for the firm capacity injected. This figure was calculated based on marginal avoided cost of "country feeder" augmentation for ScanPower (section 6.3.3). Moreover, it was assumed that ScanPower will not change their current pricing strategy. Accordingly, it follows that domestic and standard commercial

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[30] *Since HOMER Pro 1.58 generates hourly wind speeds, each record had to be slotted into two half hour time slots.*

customers are charged solely based on energy drawn from the network and not on such other variables as maximum demand and *critical peak period* pricing.[31]

- One WTG, with its capacity incrementing from 1kW, in 2 kW steps, for site wind speeds of 5.0 m/s, 6.0 m/s, 7 m/s and 8 m/s.

- One PV array, with its capacity incrementing from 0.5kW, in 1 kW steps.

- One Micro Hydro unit (run of the river type) operating at a total head of 13.5m on the Totara stream at a 10% head loss allowing a minimum of 10% water bypass. Two capacities were selected; 6.5 kW and 14.0 kW being capacities designed for annual average Totara stream flow (65.5 l/s) and maximum stream flow (144.0 l/s). In the case of the latter, the turbine remains under utilised most of the time. Two types of hydro turbines were simulated; the cross flow and low cost reversed engineered water pump, which are suitable for a 13.5m head (sections 3.3 and 3.4).

- A hybrid system consisting of one WTG and a standby diesel generator set, with wind and diesel generator set capacities incrementing from 2kW in 2 kW steps, for site wind speeds of 5.0 m/s, 6.0 m/s, 7 m/s and 8 m/s . Two load dispatch strategies were simulated for the diesel generator set. The first load dispatch strategy was for the unit to operate every day for 90 – 120 minutes during the peak farm load as determined by monthly average load profiles (Fig. 7.9). The second load dispatch strategy was for it to operate only on a hypothetical winter *critical peak period* situation where it was assumed that the country feeder gets overloaded on 36th and 37th time intervals. The number of critical peak days as well as the duration of critical peaks was varied to study the sensitivity of these variables on the financial viability of the hybrid system. As the base case, the "diesel only" was simulated.

6.3.2.2 Zone B (i.e. a small scale centralised community application)

The following systems were simulated once each for "11 kV gross import/gross export" metering and "separate generation" metering schemes (Figs. 6.12(b) and 6.13) under existing network loading levels as well as the hypothetical network overload situation described in section 6.3.2.1.

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[31] *For this reason, no customer-initiated peak lopping was assumed during peak periods because there is no incentive for a customer to reduce load if the lines company does not base its product on peak load.*

- Single WTG units similar to zone A (larger units were simulated).

- Wind-diesel hybrid systems similar to Zone A (larger units were simulated).

- A pumped hydro unit of 15 kW capacity, as determined by local topography (i.e. head and pond storage). The load dispatch strategy of the unit was assumed to be "peak lopping" in response to a hypothetical winter *critical peak period* situation on 36th and 37th time intervals on certain days. The energy charging of the pumped hydro unit (i.e. pumping water to the upper pond) was set to commence at 1.00 am after which the spot prices and the network charges remain low up until early morning (Fig. 7.1 and 7.3).

- A hybrid system consisting of a deep cycle lead acid battery bank of 18 kW (on the DC side). [32] The load dispatch strategy of the battery bank was assumed to be identical to the pumped hydro unit described above.

6.3.2.3 Zone C (i.e. a medium scale centralised community application)

Wind-diesel hybrid systems were simulated for "separate generation metering" and " 11 kV gross import/gross export" metering under the hypothetical network overload situation described in section 6.3.1.1 (base case: diesel only).

6.3.3 Calculation of the annuity ScanPower could pay to DG owners for peak lopping, in the event of country feeder overload

It was assumed that ScanPower needs to invest $ Y upfront, for each 1 kW of network reinforcement of the country feeder. It was assumed that this incremental cost is ScanPower's short run[33] marginal cost of capacity augmentation. Instead of investing $ Y upfront it was assumed that ScanPower could pay a sum of $ x each year, over several years, to any party who provides the additional 1kW capacity required, when needed (i.e. paying for DG owners who are able and willing to supply capacity during the peak period time). If '*i*' is the cost of capital of ScanPower, and it could pass the fullest possible benefit to the customer, then $Y it has to invest upfront would be equal to the present value of all future cash flows it pays to DG customers. The scenario is illustrated in Fig. 6.17.

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[32] *According to the computer model, 22 Nos. 6V deep cycle batteries of 210 Ah capacity each (C_{100} rating) are required for this purpose.*

[33] *"Short run" in economics refers to a period of time during which a firm can not vary all its production factor inputs; labour, land, capital etc (Ahuja 1998) to raise (or lower) its production output. In the case of a lines company, the production output is the network capacity.*

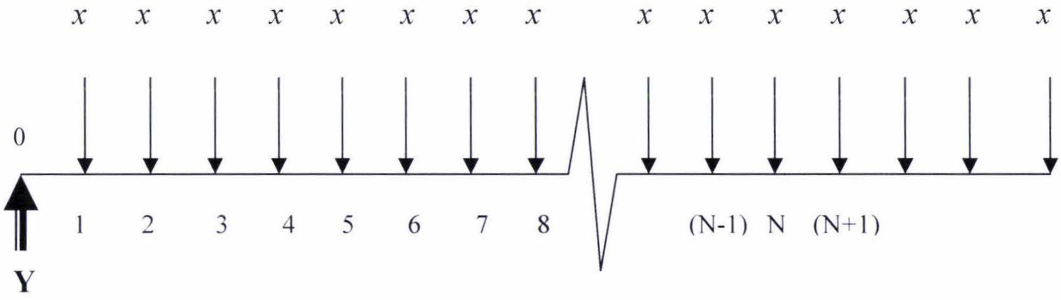

Fig. 6.17: Illustration of the concept of annual cash disbursements for additional capacity, as an alternative to capital investment

$$Y = \frac{x}{(1+i)} + \frac{x}{(1+i)^{2}} + \frac{x}{(1+i)^{3}} + \ldots + \frac{x}{(1+i)^{N-1}} + \frac{x}{(1+i)^{N}} + \frac{x}{(1+i)^{N+1}} + \ldots \textit{(infinite series)}$$

$$Y = \frac{x}{(1+i)} \left[1 + \frac{x}{(1+i)} + \frac{x}{(1+i)^{2}} + \frac{x}{(1+i)^{3}} + \ldots\ldots + \frac{x}{(1+i)^{N-1}} + \frac{x}{(1+i)^{N}} + \frac{x}{(1+i)^{N+1}} + \ldots \right]$$

$$\underset{N \longrightarrow \infty}{\mathrm{Lt}}$$

$$Y = \frac{x}{i} \left[1 - \frac{1}{(1+i)^{N}} \right]$$

$$\underset{N \longrightarrow \infty}{\mathrm{Lt}}$$

Thus, $Y = \frac{x}{i}$

If ScanPower is not passing the full benefit to the customer (i.e. to charge a monopoly rent)

then, $Y > \frac{x}{i}$

In keeping with the assumption that ScanPower passes the fullest possible benefit to the customer (i.e. , ScanPower would be indifferent to investing $Y up front to paying $ x each year to DG customers),

$x = Y * i$ Eq. 6.7

In practice a lines company will have to incur overheads to administer the payment scheme and it can charge a monopoly rent from its customers. In practice,

$x < Y * i$ Eq. 6.8

6.3.3.1 Estimation of SacnPower's short run marginal cost

As mentioned in section 7.3.2, in the average replacement of the country feeder is $ 1647/kW, assuming a feeder capacity of 1630 kW and a replacement cost of $ 2,683,900.00. The replacement covers the cost of the feeder and its associated assets such as transformers. It was assumed that 20% of the replacement cost of the country feeder covers the cost of associated assets. It was assumed that as a consequence of overload, ScanPower has to reinforce the feeder only and not its associated assets.

It was also assumed that in ScanPower's total construction cost Vs construction output curve (in terms of feeder capacity), at the point of ScanPower producing a feeder rated to1630kW, its marginal cost is approximately equal to the average cost. This situation is graphically illustrated in Fig. 6.18. In this figure, [34] the marginal cost is the slope of the tangent drawn on the curve at point A, while average cost is the slope of the line OA.

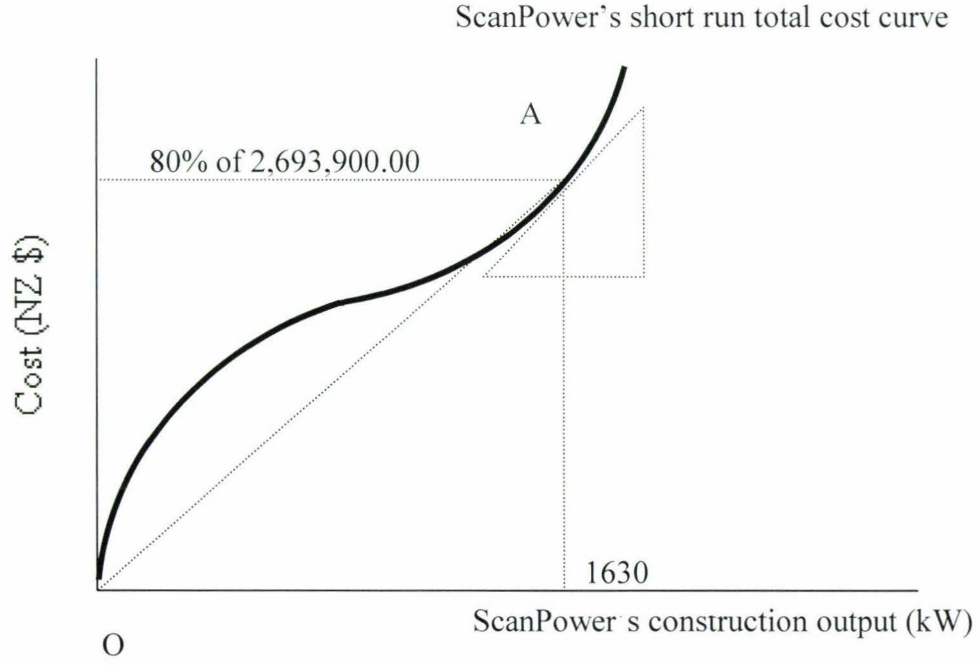

Fig. 6.18: The relationship between the total cost, marginal cost and average cost

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[34] *The shape of the total cost curve shown in Fig. O.2 is a typical short cost curve for any firm. The reason for shape of the curve can be explained by general microeconomic theory on production.*

The 5% discount rate is the minimum perceivable discount rate that could be applied (paragraph 2 of section 6.3.4). The user can use a higher discount rate. This will make NPV values much worse and DG projects will look less economic if net present value (NPV) is viewed as an absolute measure.

For the reasons mentioned in the final paragraph of section 8.1.1, NPV was viewed as a relative measure in evaluating DG projects. Hence, the interpretations (chapter 8) and recommendations (chapter 9) would not be materially affected if a slightly higher discount rate was used.

Under the above assumptions, the marginal cost of capacity augmentation at or around 1630 kW construction capacity is 0.8*1647 $/kW, which is $ 1317.60 $/kW. Assuming that the cost of capital of ScanPower is 10%, from Eq. 6.7, the variable x becomes $ 131.76.

Accordingly, subject to the above assumptions and allowing a 10% margin to administer the payment scheme and retain a above normal profit (i.e. a monopoly rent), it can be assumed that ScanPower would be willing to pay $ 120 for each kW injection provided by DG for the whole year, as and when such capacity is needed.

6.3.4 Key project economic parameters considered

- Discount rate: The discount rate is a very important variable in any project with a long life cycle. In project appraisals, it is typical to use the investor's cost of capital as the discount rate as it defines how much interest rate the investor ought to pay for every dollar borrowed. However, for risky projects it is usual to apply a premium on cost of capital in discounting cash flows, the riskier the project the higher the premium (Lucey, 1996). All cash flows were discounted at a discount rate of 5% assuming this as the cost of capital of the investor. It thus implies that the risk premium was assumed to be zero. Five percent is the official cash rate stipulated by the reserve bank of New Zealand (RBNZ, 23 October 2003).[35]

  Since renewable DG projects require funds borrowed on long-term repayment basis, and involve risk [36] the required rate of return (i.e. discount rate)[37] on any DG project is expected to be in excess of five percent. The aspect of "risk", which depends on a number of factors, is covered in section 9.2.1.

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35. *The official cash rate (OCR) is an interest rate set by the reserve bank (or central bank depending on the country) to exercise control over interest rates charged by commercial banks over short-term loans. Under the credit lines made available to commercial banks by the reserve bank, in a competitive market, no commercial bank will have an incentive to raise or lower its interest rates from the OCR (RBNZ, 2003).*

36. *Long term lending, irrespective of its intended use, always involves uncertainty for which a premium is charged by the creditor.*

37. *In projects where future cash flows are uncertain (which is termed as 'risk' in accounting terminology), the required rate of return is set higher than the cost of capital by an investor. The extra percentage the discount rate is raised over the cost of capital is called the 'risk premium' in accounting (Lucey, 1996).*

- Subsidies: As will be seen from the findings (section 8) a state subsidy is a prerequisite in making small renewable energy projects economically viable due to the present high cost of technology. Although subsidies can come in various forms such as soft loans, tax concessions and import duty concessions, the state ultimately bears the costs. In order to study the effect of accommodating subsidies, it was assumed that a certain portion of the capital required for a DG project is supplied by the state at an interest rate substantially below the interest rates charged by commercial banks on long- term loans. For this reason, before discounting cash flows, the computer model computes the applicable discount rate taking into account the proportion of the capital provided by the state (as a soft loan) to the investor, the interest rate charged, along with the investors' cost of capital, the portion of balance capital required and the risk premium (section M.1, Appendix M).[38]

- Initial project cost estimation: Initial project costs used for of all project components were the costs suggested by the model's cost prediction algorithm.

- Charges for grid injection: It was initially assumed that no charges shall be levied by ScanPower for any form of DG, which is the actual case. Subsequently, for economically more favorable projects, a $/kW/year (on installed capacity) figure was assumed for grid injection to study the sensitivity of charging for grid injection based on installed capacity.

All the figures used for simulation as well as justification for same (where applicable) are shown in Appendix P.

6.3.5 Totara Valley simulation results

Chapter 8 provides a discussion on sensitivity results on the simulation of DG systems. Some specimen three page summary reports outputted by the model are attached in Appendix Q as additional information (sections Q.1, Q.3, Q.4 and Q.5). In chapters 8 and 9 an attempt has been made to generalise simulation results to a wider rural New Zealand context.

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[38] *The adjusted cost of capital can be viewed as the investor's final weighted average cost of capital.*

Chapter 7

The Descriptive Statistics

This Chapter covers the descriptive statistics of key variables used in the computer model as well as other relevant statistics pertaining to Kumeroa community and rural New Zealand[1]. In addition, performance data pertaining to the solar hot water system and the PV modules supplied to the farmhouses are also covered.

7.1 SPOT PRICE STATISTICS

The spot prices generally keep step with the national aggregate load profile (Figs. 7.1, 7.3 and 7.5). This is an expected result since the spot price is determined by the marginal cost of the last generator who is connected to the grid and that more expensive (in terms of bidding price which is assumed to be the marginal cost of electricity production) offers are dispatched to the grid only as the load picks up. However, it is also clear that the spot price variations cannot be explained purely from supply side dynamics since the spot price seems to be fluctuating erratically in certain months as well as the time interval of the day. For example, Oct 2002 weekday spot price fluctuation (Fig. 7.2) and January 2002 weekend spot price fluctuation (Fig. 7.4). Fig. 7.1 and 7.3 suggest that spot prices can rise by 300% to 400% in certain months (on average), especially on weekdays. For example, on average, October weekday spot prices rose up to 6 c/kWh during the morning peak from the early morning price of about 1.5 c/kWh.

Comparison of statistics depicted in Fig. 7.3 with Fig. 7.1 suggest that weekend prices are not necessarily lower than weekday spot prices even though the national aggregate load on weekends and public holidays is much lower than weekdays (Fig. 7.6). One possible reason for this is the alterations in the generator offer schedule and the grid constraints on weekends due to some generating plants (including low cost hydro) and transmission lines being taken out of service for maintenance.

Based on the above observations it was concluded that it was not necessary, as far as the computer model is concerned, to synthesise weekend spot prices separately. Accordingly, for a given month, only weekday mean prices and the coefficient of variation were

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[1] *The phrase "descriptive statistics" is used here in a non-technical sense to mean usage of data to describe any aspect of any variable. Descriptive statistics (as distinguished from inferential statistics) in strict technical sense covers three aspects of a variable; its central tendency (e.g. mean, median, mode), the shape (e.g. continuous Vs discrete, skewness) and the dispersion (e.g. variance, standard deviation, coefficient of variation).*

used to synthesise half-hourly prices.

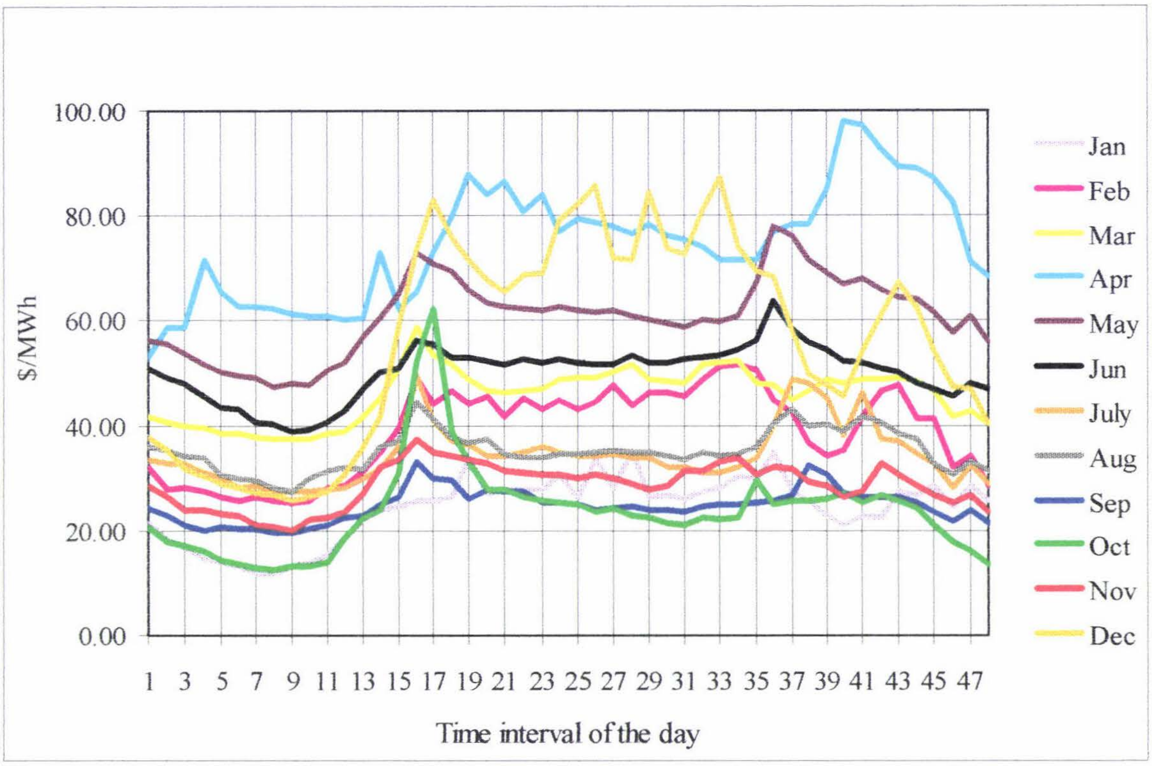

Fig. 7.1: Monthly average weekday sport prices at Haywards GXP in 2002 *(Source: Based on half hourly final spot prices published by M-co)*

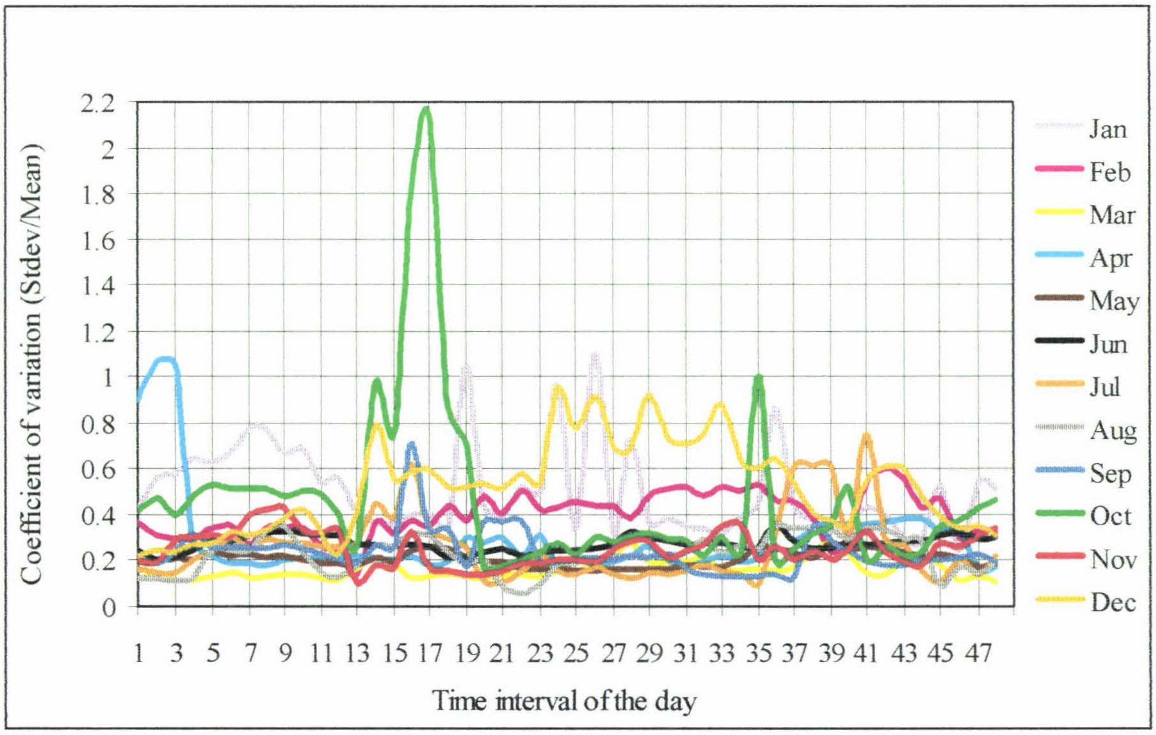

Fig. 7.2: Monthly variability of weekday sport prices at Haywards GXP in 2002 *(Source: Based on half hourly final spot prices published by M-co)*

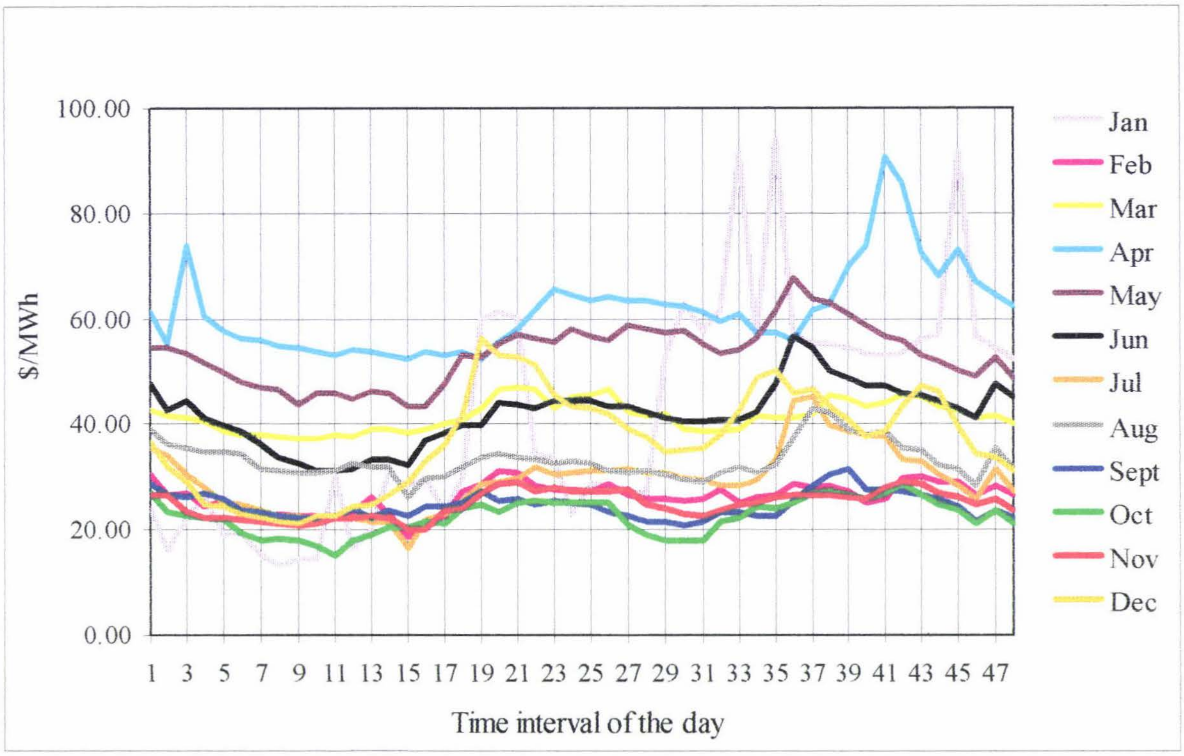

Fig. 7.3: Monthly average weekend sport prices at Haywards GXP in 2002 *(Source: Based on half hourly final spot prices published by M-co)*

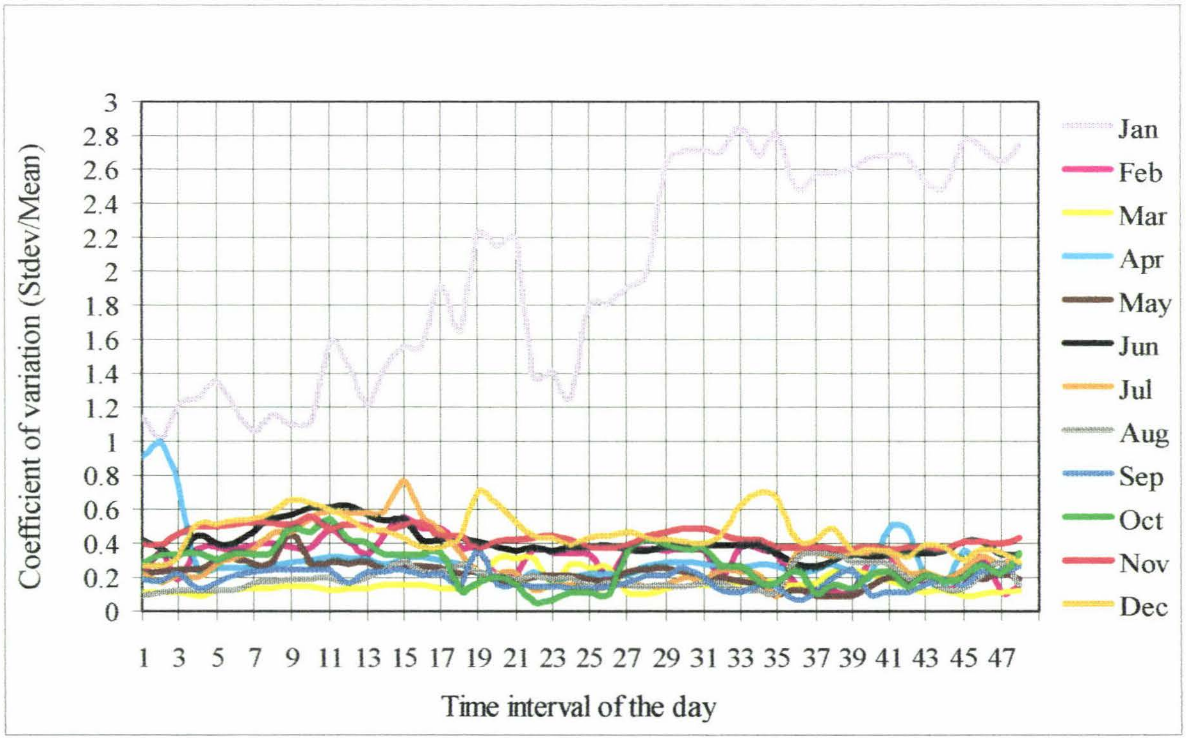

Fig. 7.4: Monthly variability of weekend sport prices at Haywards GXP in 2002 *(Source: Based on half hourly final spot prices published by M-co)*

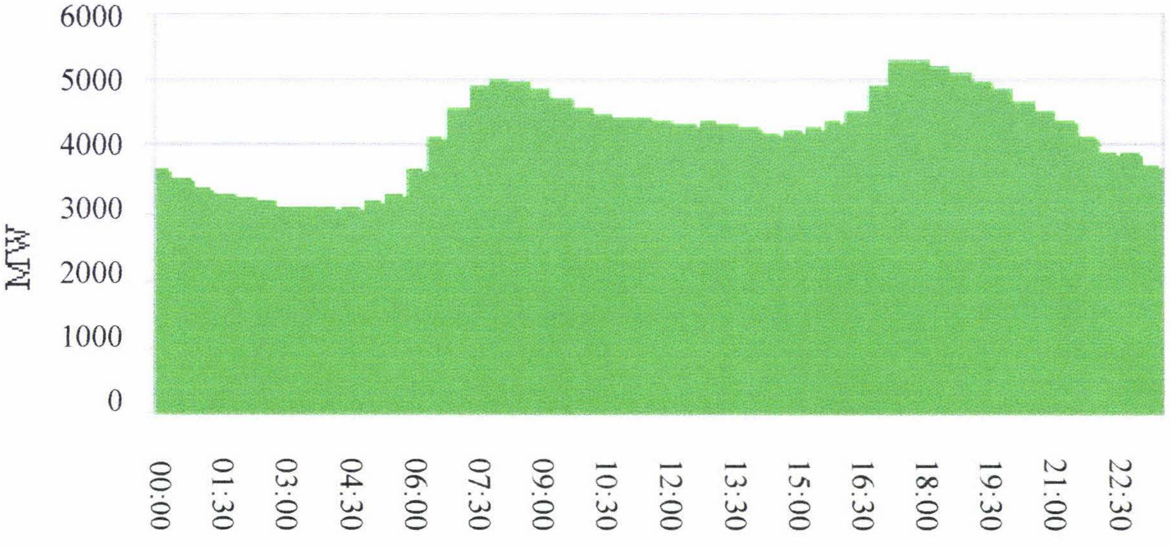

Fig.7.5: The national average half-hourly daily load *(Source: M-co, 2003)*

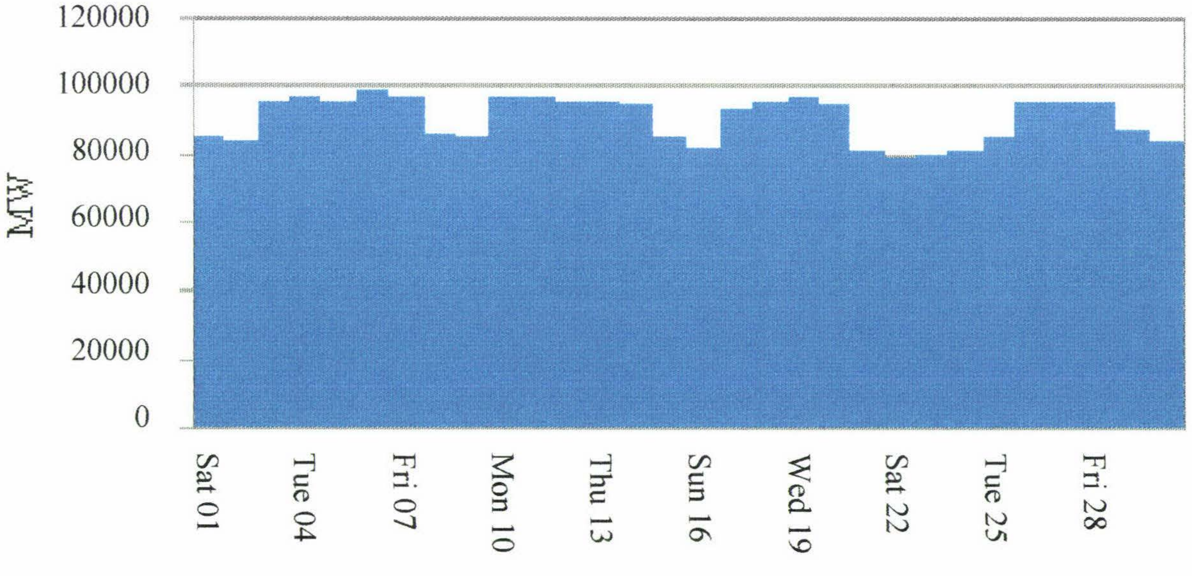

Fig. 7.6: The pattern of national daily average load in April 2002 *(Source: M-co, 2003)* [2]

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[2] Please note the trough from Friday April 21st to Monday April 24th owing to the long Easter holiday.

7.2 STATISTICS OF RURAL NEW ZEALAND

7.2.1 Demographics

According to 2001 national census, 532,740 New Zealanders (approximately one in seven) were living in rural areas, with two thirds in the North Island. The Nelson Region (675) had the fewest rural residents, while Waikato (85,296) had the most. The other regions with more than 40,000 rural residents were Canterbury (69,447), Northland (68,115), Auckland (47,295), Bay of Plenty (47,064), and Manawatu-Wanganui (42,381). After Nelson, the region with the fewest rural residents was Marlborough (8,946). Also see Fig. 7.7a and Fig. 7.8b.

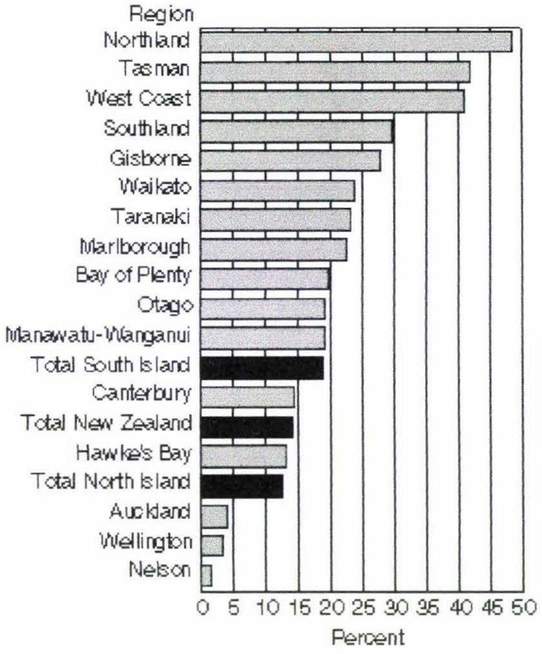

Fig. 7.7a Proportion of the population living in rural areas by Regional Council area

(Statistics New Zealand, 2002)

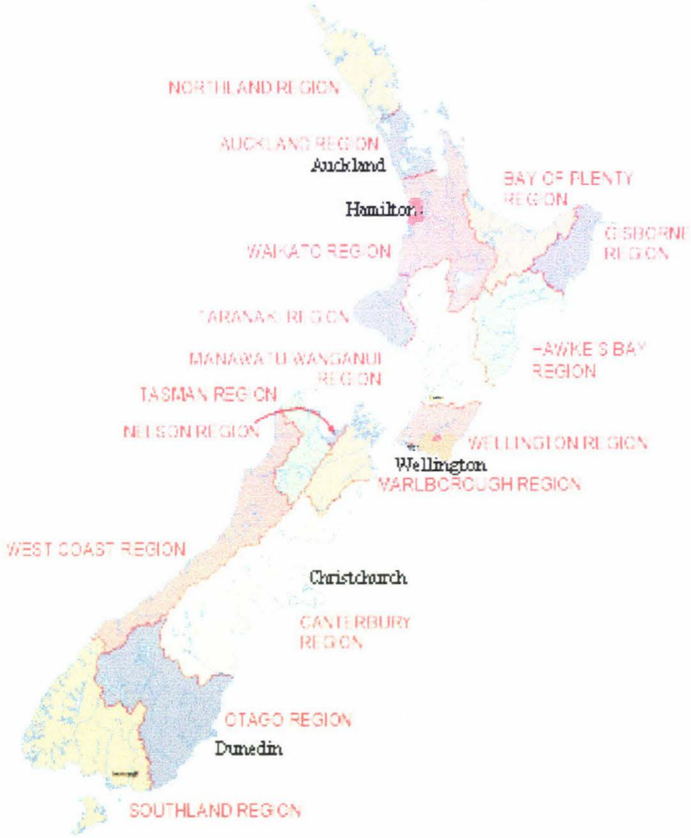

Fig. 7.8b New Zealand regions
(Statistics New Zealand, 2002)

7.2.2 Income, occupation and household amenities

According to the 2001 census, the median rural household income of ($ 19,100 p.a.) was higher than the urban households ($ 18,400 p.a.). Among rural settlements, those with a smaller household concentration (less than a population of 300 people) had a higher median income ($ 19,800 p.a.) than those in rural centres ($ 15,600 p.a.).

97% internet access referred to in line 2. paragraph 2 of page 160 is based on the abstract released by Statistics New Zealand on year 2001 census. Hence it is a credible piece of information. The data is downloadable from the Statistics New Zealand's official website (http://www.stats.govt.nz).

As regards employment, slightly over 1 in 3 rural adults were engaged agriculture or fishery related employment (compared to 1 in 26 of those living in urban areas). In smaller rural settlements the proton of agriculture and fishery related employment were prevalent (more than one in three) compared to rural centres, where the proportion stood at 1 in 6.

In terms of household amenities, the proportion of households with internet access was nearly on par with main urban areas (97%) while in terms of access to number of motor vehicles the rural households clearly outdid the urban households (for example 1 in 5 rural households had access to three or more vehicles compared with 1 in 8 of their urban counterparts).

Although not fully conclusive, the above data suggest that rural communities are not at an economically disadvantageous position in terms of raising the capital required for distributed generation projects.

7.3 STATISTICS ON THE DISTRIBUTION SYSTEM OF KUMEROA/TOTARA VALLEY

7.3.1 ICP/customer classification and the load use pattern

Table 7.1 lists customers/ICPs in Zones A, B and C as per the classification used by ScanPower. In general, Zone A is representative of Zone B in terms of the electrical distribution system (i.e. the farmhouse, the cottages and the woolshed of each farm being fed by single 30kVA transformer) and the customer load use. However, farms outside Zone A but belonging to other two zones had several single phase and three phase LV supplies used solely for water pumping. ScanPower classifies such one-off end use commercial applications as C1.2 or C1.5 customers depending on the installed capacity (Table 7.2). The latter category involves larger water pumps that use three phase supplies. In Zone C, in the Kumeroa township, there exists a dairy farm, a school and a community centre. Such ICPs, which have distinct load profiles, were non-existent in Zones A and B.

Appendix – N describes how Zone A data were used to compute Zone B and Zone C data (means and the coefficients of variations), for the purpose of applying the computer model for Zones B and C.

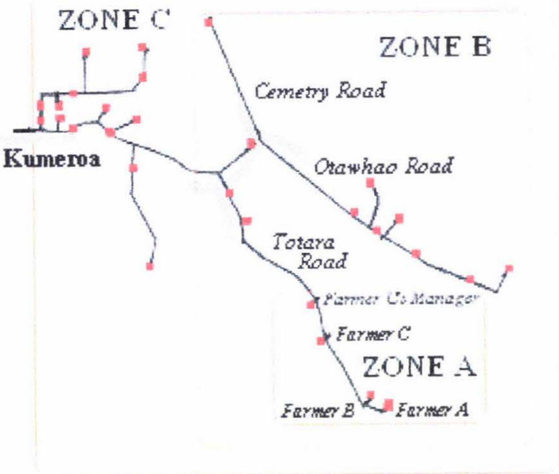

Fig. 7.8: The zones covered by the simulation

Zone Reference	Customer/ICP category			
	D	**C1**	**C1.2**	**C1.5**
Zone A	7	4	0	0
Zone B	32	13	3	3
Zone C	50	21	10	7
Outside Zones C	121	77	36	32
Total on the country feeder	210	115	49	42

Table 7.1: The disposition of customers based on the classification used by ScanPower

Sr.	Customer/ICP Category Code	Description
1.	D	Domestic customers/ICPs.
2.	C	The standard commercial customers: Customers with an installed capacity equal or greater than 8kVA with an annual energy consumption of less than 100,000 kWh
3.	C1.2	Point loads of less than 2kVA installed capacity
4.	C1.5	Point loads of less than 5kVA installed capacity

Table 7.2: Abbreviations used for customer/ICP category

7.3.2 Statistics of the "country feeder"

Table 7.3 depicts some relevant data on the country feeder. It is evident from this data that even on a very "peaky day", the county feeder operates at about 40% of its designed capacity (assuming that the over current trip setting is set 10% above the continuously rated designed capacity of the feeder). It is also clear that if ScanPower were to replace the country feeder with a new feeder, it would cost them $ 1647 per kW (assuming that the continuously rated designed capacity of the feeder is 1630kW).

Sr.	Parameter	Description
1.	Average daily load on the peak month (July) *(as reported by ScanPower)*	422 kW
2.	Average daytime (7:00 am to 11:00 pm) load during the peak month *(as reported by ScanPower)*	473 kW
3.	Average nighttime (11:00 pm to 7:00 am) load during the peak month *(as reported by ScanPower)*	319 kW
4.	Estimated peak load on the peakiest day of the peak month[3]	660 kW
5.	The overload setting of the feeder, based on the "over current relay plug multiplier setting" *(as reported by ScanPower)*	100 A (=1793 kW approx)[4]
6.	The conductor sizes and lengths from the substation up to end of Zone A (also see Appendix - E)[5]:	
	1st section 5.025 km	105 mm^2 ACSR[5,6]
	2nd section 9.875 km	40 mm^2 ACSR
	3rd section 2.500 km (up to Zone C interface)	20 mm^2 ACSR
	4th section 3.250 km (up to Zone B interface)	20 mm^2 ACSR
	5th section 5.250 km (up to end of Zone A)	16 mm^2 Copper
	Total length 25.9 km	
7.	Feeder replacement cost (as furnished by ScanPower)	$ 2,683,900.00
8.	Feeder depreciated cost as on 01 April 2002 (as furnished by ScanPower)	$ 1,682,694.00

Table 7.3: Statistics pertaining to the 11 kV "country feeder"

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[3] *Assuming that the average load on the peakiest day is 20% more than the daily average load for July and that the load factor on that day is 0.70.*

[4] *Assuming a substation busbar voltage of 11.5 kV and a power factor of 0.90.*

[5] *ACSR stands for Aluminum conductors with steel reinforcement. The data as per ScanPower's system diagram for the Woodville substation.*

[6] *The conductor type and the conductor size are important for engineering studies involving voltage drops and power losses. For this purpose, one needs to know the AC resistance and the inductive reactance of the feeder (per km), feeder length and the load distribution pattern. For example, 40mm^2 ACSR conductor has an AC resistance and an inductive reactance of approximately 0.90 Ω/km and 0.31 Ω/km respectively. This means if a current of 10A (=162 kW approx.) is flowing in the 40mm^2 ACSR conductor, it would amount to a power loss of 90W per phase, per km, according to the power = $current^2$ * resistance law.*

7.4 LOAD RESEARCH DATA

7.4.1 Aggregate farm loads

Based on the data logged (section 5.8.1), the average (mean) load of the three farms during each half hour interval for each months for the six months monitored is shown in Fig. 7.9. Apart from the loads of each farm, Fig. 7.9 also depicts the load of a representative hill country sheep and beef farm, which was assumed to be the mean of the average loads of the three farms. From a statistical perspective, the mean value drawn from a sample size of three can cause significant errors if any one of the farms happens to an "outlier" as far as the sampling frame is concerned.[7] However, in the absence of a sufficient sample size, there is no other known way to determine a representative figure than averaging the value of farms A, B and C and this procedure is consistent with Eq. 4.3 referred to in section 4.3.

Farm A load in general, seem to be higher than the other two farm loads at any time of the day. All three farms generally show a clear night peak followed by a drop in load. However Farm A load in general, seem to be fluctuating more rapidly during the day than the Farm B and C loads. For example, four load peaks are visible in August in Farm A, including a midnight peak. Although load fluctuates during the day in Farm A, Fig. 7.10 suggests that the variability of load (expressed in terms of the coefficient of variation) during any half hour interval of any month appear to be less than for the other two farms.[8] This observation eliminates the possibility of any metering malfunction in Farm A.

7.4.2 Monthly energy consumption of individual installations

Fig. 7.11, 7.12 and 7.13 depicts the monthly energy consumption of the individual installations of the three farms. In farms B and C the farmhouse load was considerably higher than the loads of its other installations. In Farm A however, the cottage loads were higher than the farmhouse load. Three reasons could be attributed to this. Firstly, there is an additional cottage in Farm A. Secondly, one cottage was being occupied by the joint owner of the farm who had a high disposable income with a range of electrical goods

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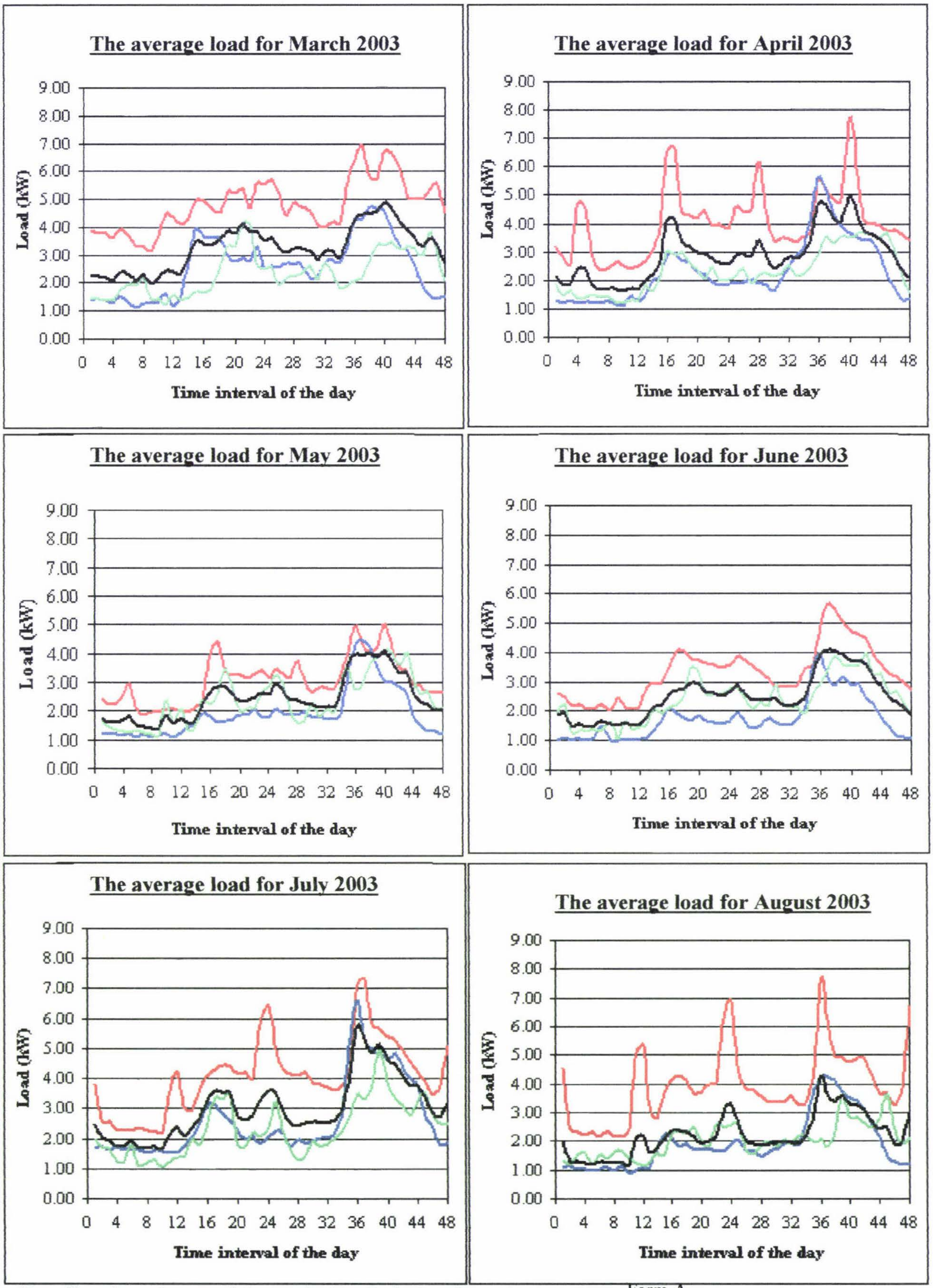
[7] *In a proper statistical study, one needs to obtain data from sufficient number of farms so that the researcher can plot data and identify those which do not fit into the pattern of others (such data points are termed as 'outliers' in statistics) . Since such outliers can cause significant bias, it is necessary to exclude the same in any statistical function including averaging. Such freedom is not available when one deals with load research on only three farms, even if the sampling frame is Zone C and not all of the sheep and beef farms in New Zealand.*

[8] *Note that the data in Fig. 7.9 and 7.10 are based on aggregate farm loads. The scope of the research does not include determining the factors that affect the load patterns of the three farms. If this is the case, real time load monitoring should be undertaken at a more disaggregated level. See 7.4.2 for a generic presentation of energy consumption patterns at a disaggregated level.*



The average load for March 2003

The average load for April 2003

The average load for May 2003

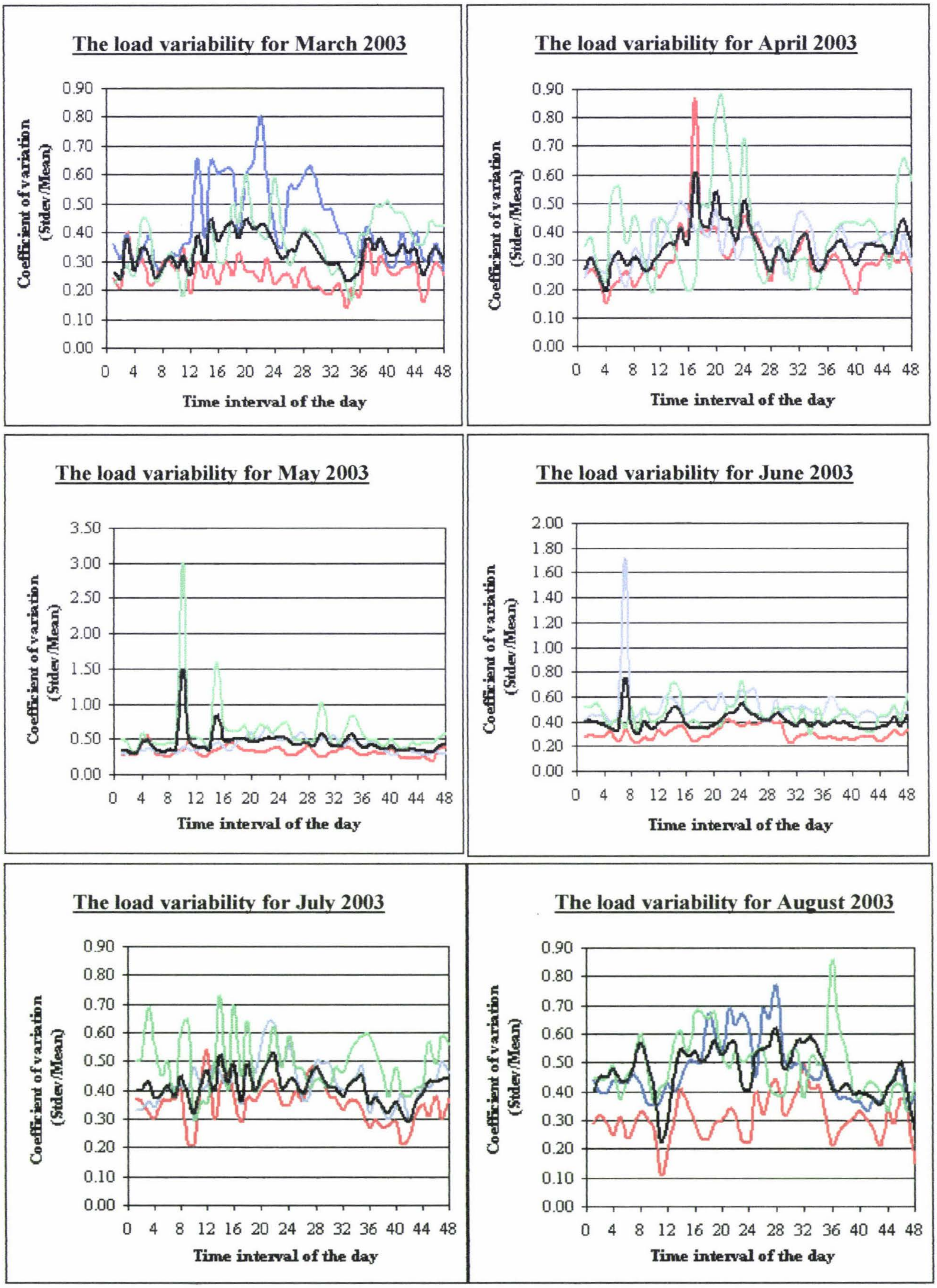
The average load for June 2003

The average load for July 2003

The average load for August 2003

Note: Since the study covered data monitoring of only three farms, the profile of a representative farm had to be derived by averaging the corresponding values of the three individual farms A, B & C.

Fig7.9: The half hourly average values of Totara Valley load data monitored



Note: Since the study covered data monitoring of only three farms, the profile of a representative farm had to be derived by averaging the corresponding values of the three individual farms A, B & C.

Fig7.10: The half-hourly variability of Totara Valley load data at his disposal. Thirdly, the number of usually resident occupants in the farmhouse was reduced from three to two in mid March 2003.

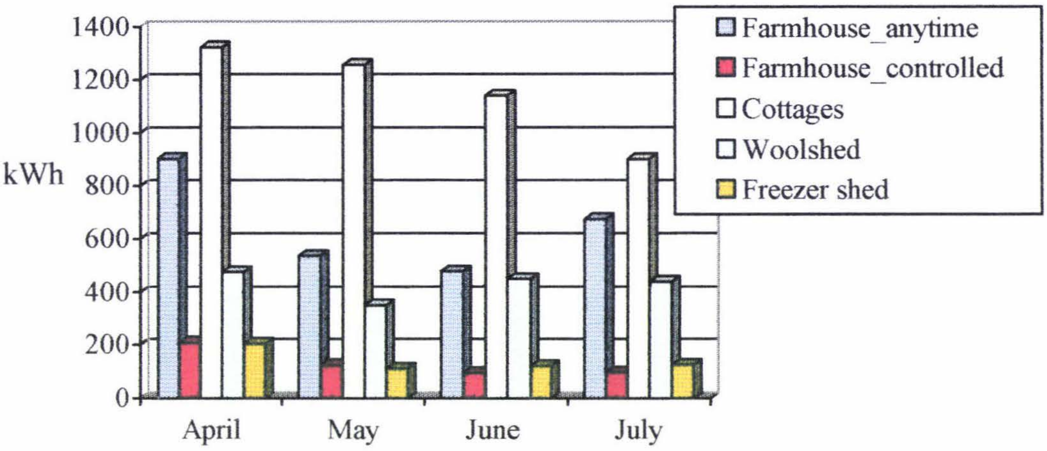


Fig. 7.11: Monthly energy consumption at Farm A installations based on utility tariff meters

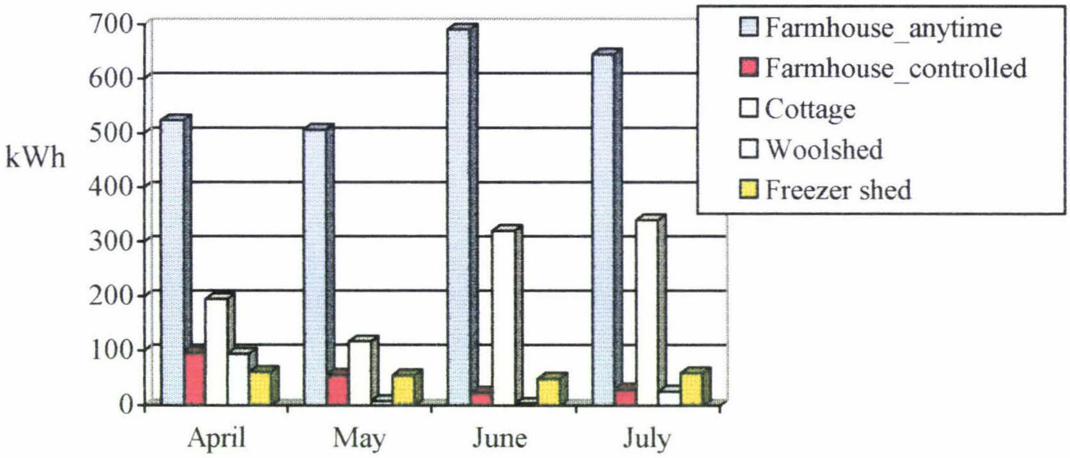


Fig. 7.12: Monthly energy consumption at Farm B installations based on utility tariff meters

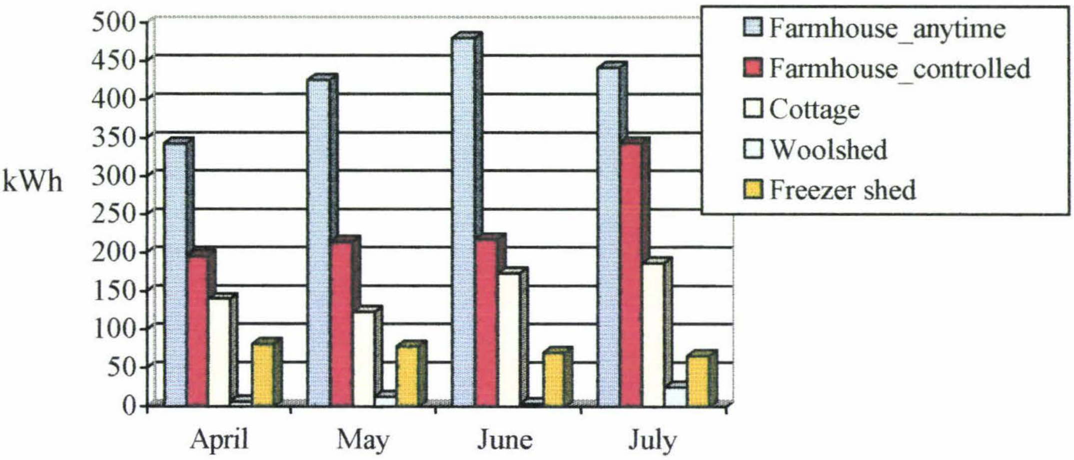


Fig. 7.13: Monthly energy consumption at Farm C installations based on utility tariff meters

Although the occupants in the farmhouse of Farm A switched off the electricity supply to the hot water tank of the solar hot water system completely from May to July with a view to patronise with the government's request to save energy, the retailer's "controlled energy meter" continued to record about 100 kWh in each month (Fig. 7.11). This was because a second electric hot water tank was in operation for the laundry. Occupants of the farmhouse in Farm B too were able to save hot water electricity costs during the above period due to having a heat pump and the wetback stove in service (Fig. 7.12). As regards the farmhouse C, the electric hot water load remained a significant component of the domestic load. The reason for this is that although the farmhouse was equipped with a wetback stove, the occupants did not use it apparently due to the high opportunity cost of maintaining the fire due the chief occupant having to devote a considerable amount of time on his secondary employment.

7.4.3 The Summer load profiles

Since the load research was undertaken only during the autumn and the winter, it was necessary to search for secondary data from previous load research on Totara Valley so that summer load parameters (mean and standard deviation for each half hour of each month) for the computer model could be determined. In this regard, Fig. 7.14 depicts the summer and winter average half-hourly loads for each half hour, based on load data collected by Murray (2002) and published by Gardiner *et al* (2002) and Murray (2002). The summer evening peak was steeper and higher than the winter peak, which is not the norm for the lines company ScanPower. According to ScanPower, all of their network sections get loaded more in the winter months. Fig. 7.15 depicts the Totara Valley summer load as a fraction of the winter load, based on data depicted in Fig. 7.14. The summer/winter load fraction was used to compute the load parameters for summer months (Appendix - N).

7.5 THE SOLAR HOT WATER SYSTEM PERFORMANCE

The performance of the solar hot water system in Farm A in March 2003 is shown in Fig. 9.16. Overall, nearly 2/3 of the energy required for hot water heating had been provided by the solar energy. This was in spite of a above-average water demand in the farmhouse up until 15th March, on which date a family wedding took place. From this date the number of occupants of the household was reduced to two. On average, 5.51 kWh of solar energy

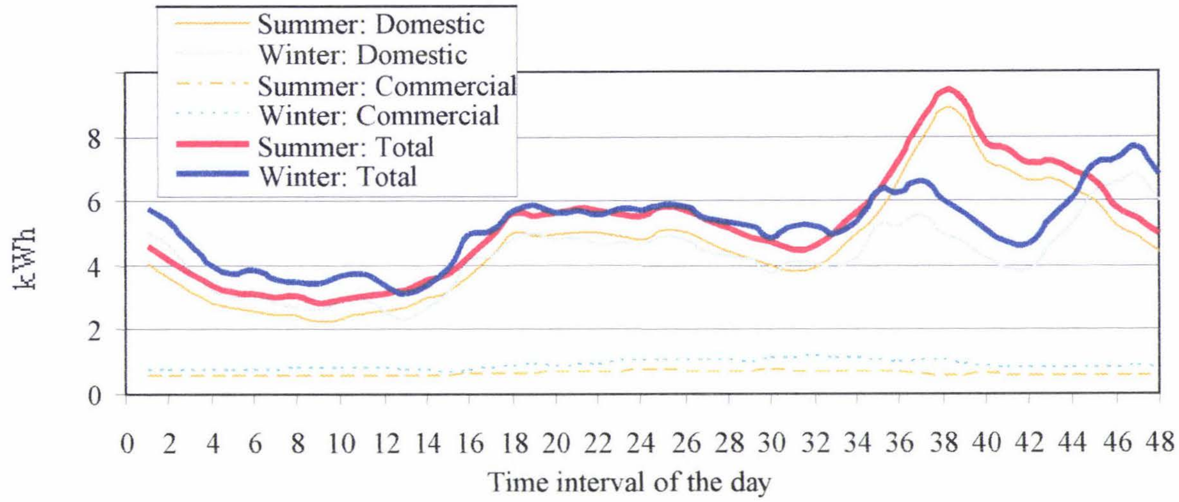


Fig7.14: The summer and winter half-hourly average loads for Totara Valley based on previous load research data *(Gardiner, 2002)*

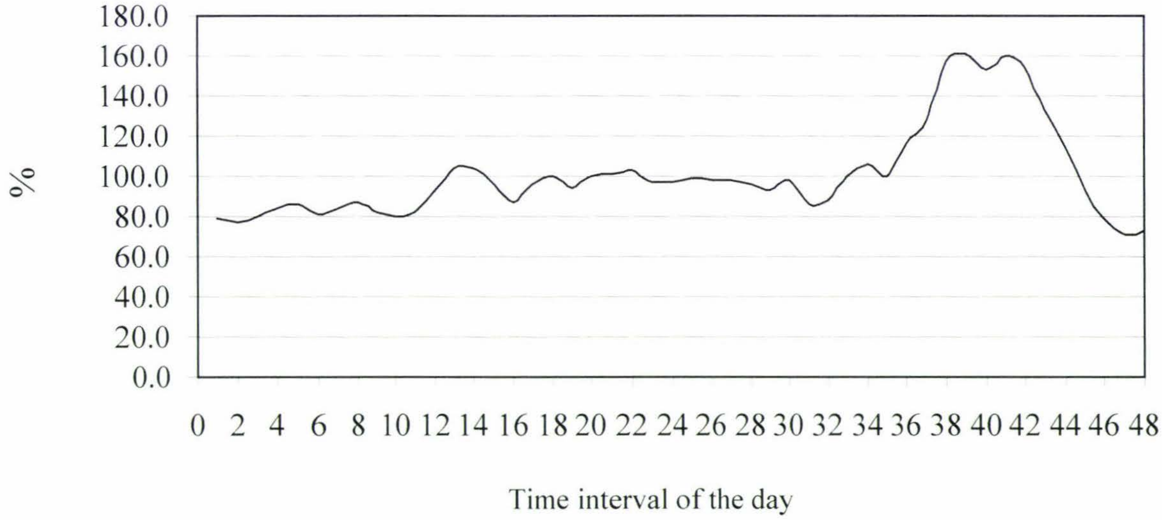


Fig7.15: Totara Valley summer loads as a percentage of winter loads, based on previous load research data (derived from Fig. 7.11)

has been provided by the system in March. Considering the fact that the area of the four flat plate solar collectors is 3.5 m^2 and that the average sunshine for the month on a horizontal surface is 4.85 kWh/m^2 (Fig. 7.18), which when expressed as the sunshine on the flat plate collector surface is 5.81 kWh/m^2 (assuming the slope of the roof to be 42^0), the solar collector in average has operated at 27% efficiency, which is satisfactory.

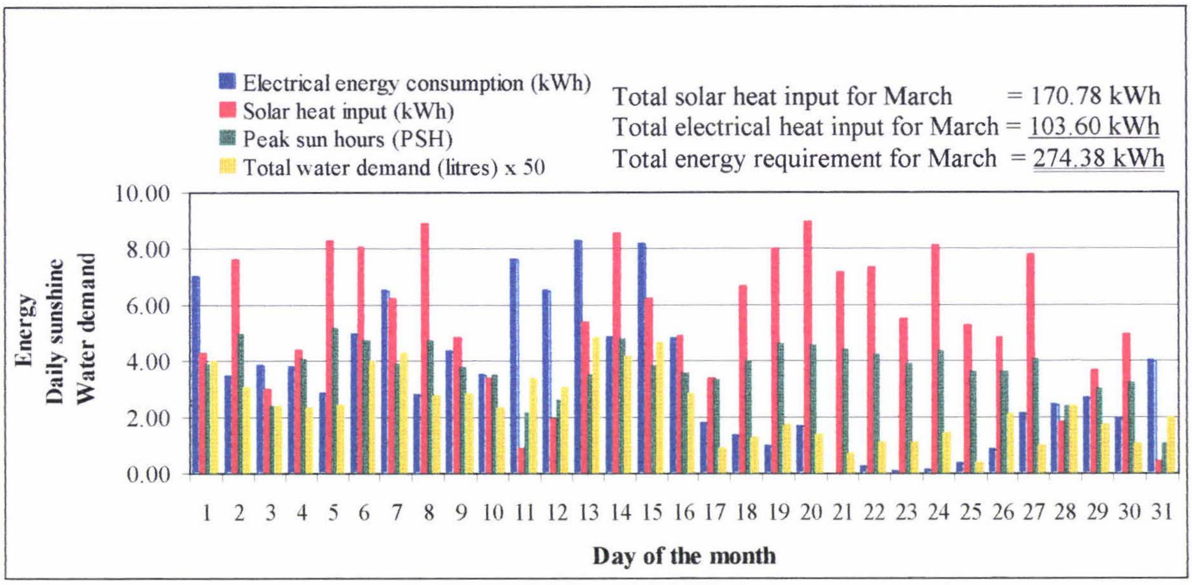


Fig. 7.16: The Solar hot water performance in March 2003, calculated from measured data[8]

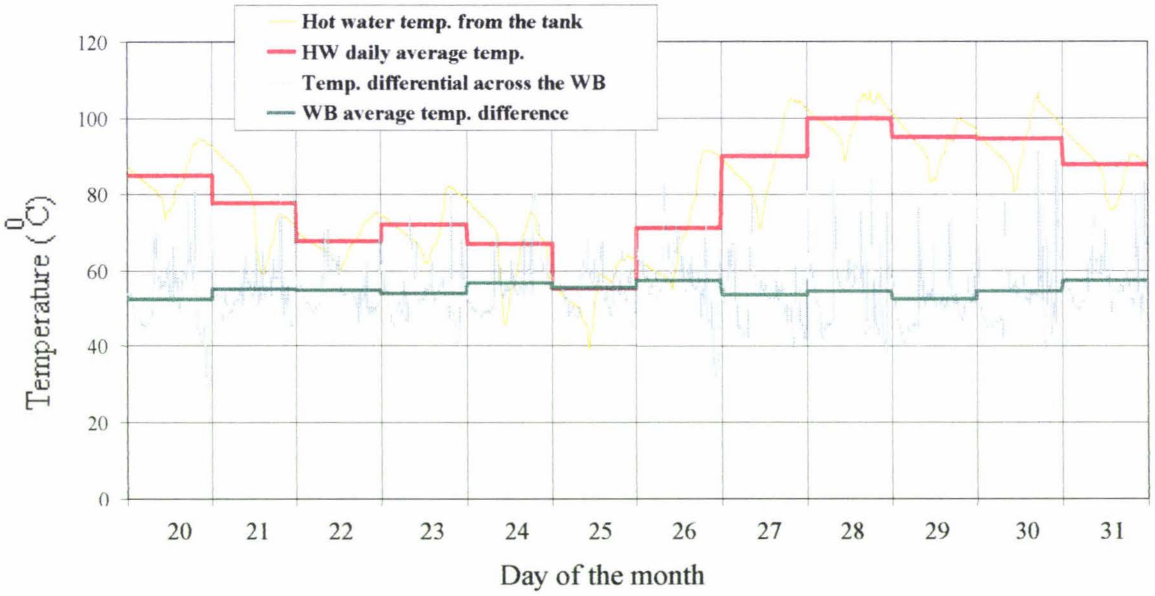


Fig. 7.17: The results on experiment on the hot water system conducted between 20 May 2003 to 31 May 2003 with wetback (WB) as the only heat source

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[8] *The sunshine is shown in peak sun hours. Peak sun hours (PSH) during a given period refers to the (hypothetical) number of hours solar irradiation of 1 sun (i.e. 1 kW W/m^2) that would contain the same energy quantum as the energy during the period under consideration. Accordingly, numerically, the sunshine expressed in kWh is the same as the sunshine expressed in PSH. Also, note that the sunshine is the sunshine incident on a horizontal surface and not on the surface of the flat plate collector. The latter could be found from the computer model because it does this calculation for a PV array.*

The occupants (an elderly couple) of the farmhouse as usual brought their wetback firewood stove into operation in the first week of May 2003 and kept it going through out the winter (June through August). In analysing April data, it was observed that the solar hot water performance was lower than expected and it was later found that the heat transfer fluid (propylene glycol) pump had been operating without adequate fluid. The solar hot water system was switched off on 19th May 2003 and with the permission of the occupants, the electric heating was also kept off (it was making a very little contribution anyway, owing to the wetback) in order to study the behavior of the system for the rest of May, with the wetback as the only heat source (Fig. 7.17). Even on the high demand day of 25th May (Saturday) the hot water temperature (in average) was meeting the minimum

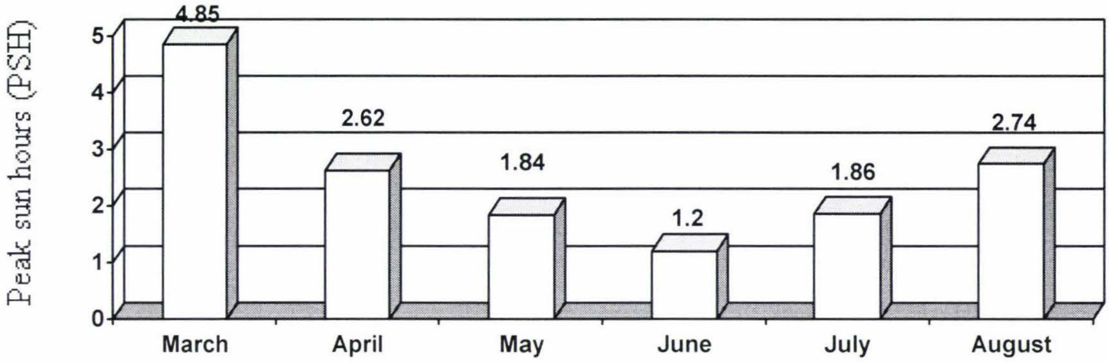

Fig. 7.18: The average daily sunshine on a horizontal plane in Farm A

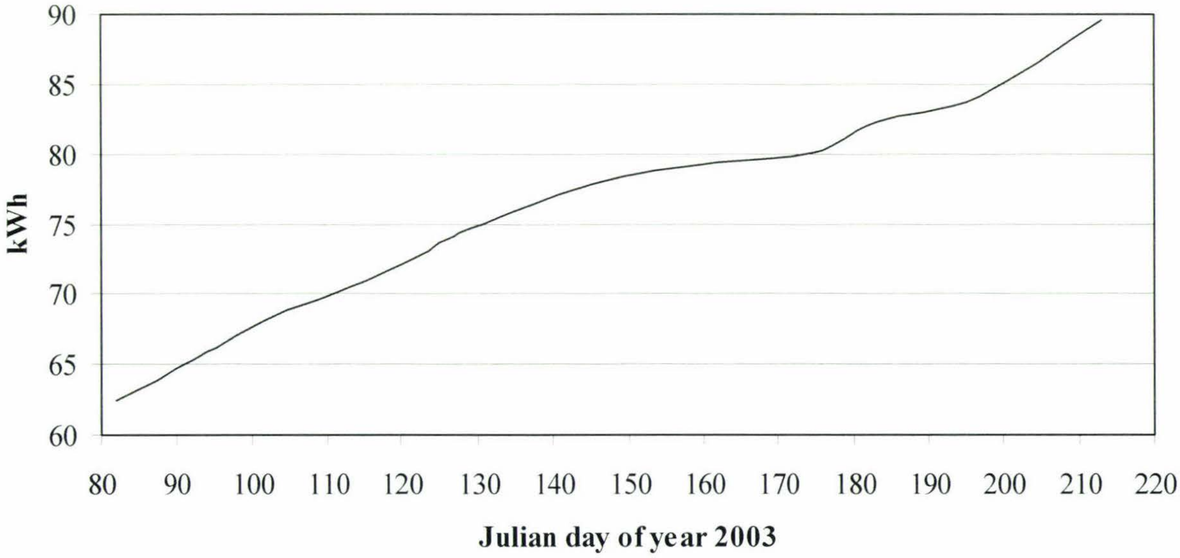

Fig. 7.19: The cumulative energy generation of the 100Wp AC PV module on Farm C since commissioning on 25 September 2002

desired temperature. However, as seen in Fig. 7.17, the temperate regulation of the tank throughout the period was poor, as the user had little or no control over the tank temperate.

Fig. 7.17 also suggests that the amount of heat supplied by the wetback is approximately the same each day, assuming that the average daily temperate differential across the wetback pipes could be reckoned as a proxy for heat transfer. The result also implies that the daily routine of dealing with the fire stove remains the same during such short periods as 11 days .

Upon rectifying the defect of the pump malfunction in early June, the solar performance was analysed and it was found that the solar contribution on most days has been marginal, due to the wetback in operation (as mentioned earlier, the occupants opted to leave the electric heating off during the rest of the winter, even though it may not have been required anyway, due to high tank temperatures).

7.6 THE PERFORMANCE OF THE PV MODULES

The performance of the 100Wp AC PV module in terms of energy generation is depicted in Fig. 7.19. As expected the rate of energy generation was the lowest in June (152 to 182 Julian days). Comparing the actual results with the model, it was observed that June generation, as indicated by the energy meter, was nearly 70% lower than the value predicted by the computer model. The difference for April however was only 4 %. The reason for this discrepancy is explained below.

As mentioned in section 5.8.3.2, the digital energy meter picks up only a generation above 12W. Assuming that the meter picks up when the inverter is outputting 13W (which is 13% of the rated inverter capacity) and that the inverter efficiency is 40% (at 13% loading level) it means that any generation below 32.5 W by the module would not be picked up by the meter. This means that any generation corresponding to an incident solar irradiation below about 325 W/m^2 (on the plane of the array) goes unrecorded by the energy meter, which indeed is a signification proportion during winter months, in particular, in the month of June.

CHAPTER 8

The analysis of Totara Valley simulation model results

This chapter analyses the simulation results of different distributed generation (DG) hardware configurations operating under various electricity market conditions. Each simulation differed from one another in terms of installed capacity (size) of the generating units, the available renewable energy potential, the technology, type of the metering scheme implemented, New Zealand electricity market prices and the lines company tariffs. In addition to the above, some simulations were run based on hypothetical situations such as availability of subsidies (to renewable DG entrepreneurs) and payments by lines company to the DG owners for supplying capacity to the network.

The net present value (NPV) to the investor was reckoned as the yardstick for evaluating financial attractiveness. Since only those projects that are relatively financially viable (from an investor's point of view) pose opportunities and threats to a lines company, only such projects were discussed from a lines company perspective.

8.1 THE BASIC FRAMEWORK USED IN THE ANALYSIS

8.1.1 The project financial indicators

Of the project financial indicators, net present value (NPV), internal rate of return (IRR) and profitability index (PI) have been derived using discounted cash flow techniques. These indicators, which take time value of money into account, are superior to the simple financial indicators, payback (PB) and accounting rate of return (ARR). In evaluating different distributed generation (DG) options and operational strategies, NPV was used as the common yardstick to evaluate the financial feasibility. According to the NPV method, an investor, having determined his or her required rate of return (assumed to be the cost of capital), would only undertake a project if the NPV is equal or greater than zero, because the overall objective of the investor is normally to maximise his or her profit.

Two issues arise when the above approach is applied to renewable energy projects.

1) NPV and other traditional project financial indicators are based on the mainstream economic thought "the economic man"; a person who can always foresee the consequences of his actions, who always acts rationally, and who is always trying to maximise his profit. Such a person is assumed to be capable of listing all

alternative investment opportunities at his disposal, ranking them in the profit earning order and selecting the most financially profitable investment option (Ranasinghe, 2001). The appropriateness of the assumptions concerning the behavior of the "economic man" in today's context is very debatable. The decision-making environment of the contemporary investor is very complex and his or her capacity for rational action is limited by the lack of knowledge of the total consequences of his or her decision and by personal and social ties. Therefore, an investor strives not to maximise profits but to find acceptable solutions to acute problems (Carlson, 1978).

2) The learning curves of key DG components exhibit low progress ratios, which means projects that are marginally uneconomical today (in a net present value sense) would become economical in the near future if the production capacities of the technologies could be increased. This could only be realised increasing application of such components in DG projects.

For the above reasons, when analysing projects, NPV was reckoned as a relative index and not an absolute index. NPVs, which were closer to zero compared to the initial investment, were considered to be acceptable projects that need immediate attention of the stakeholders in the decision environment; the investor, the state and the lines company.

8.1.2 The scope for generalising the analysis

In this study, data collection was confined to three farms in Totara Valley and the price structures of the local lines company ScanPower for the most part. However, there is plenty of scope for generalising the results.

The analysis on Totara Valley net metering schemes can be generalised to any other consumer willing to undertake a DG project, so long as the annual energy consumption of that customer matches the annual energy consumption as measured by the Totara Valley examples. The Totara Valley "gross import/gross export metering" projects covered in the analysis could be thought of as analogous to any other consumer having a similar load profile. The "separate generation and load metering" projects covered can be generalised to any other DG project where generation is separately metered, because the load does not generally become a direct factor affecting the revenue stream generated by the project.

However, the load does become a factor in "separate generation and load metering" if the customer is charged based on critical peak period load and if there is a separate meter to record the critical peak period consumption. Under such a condition, a customer is able to reduce the line charges imposed, if the customer initiates load shedding during the critical peak periods signaled by the lines company. This amounts to an increase in net cash inflows of the project.

8.1.3 The approach used for analysing the effect of subsidies

One extreme case of subsidy could be thought of as a situation where the entire capital required for the project is supplied as a zero interest loan by the state (i.e. a direct subsidy). In a scale of incentives, such a project can be considered as maximum incentives provided. On the other end of the scale, there could be a project for which no incentives are provided (as is currently the situation in New Zealand). Any project could be considered as "subsidised" where the level provided occupies any position in a continuum of incentives (Fig. 8.1).

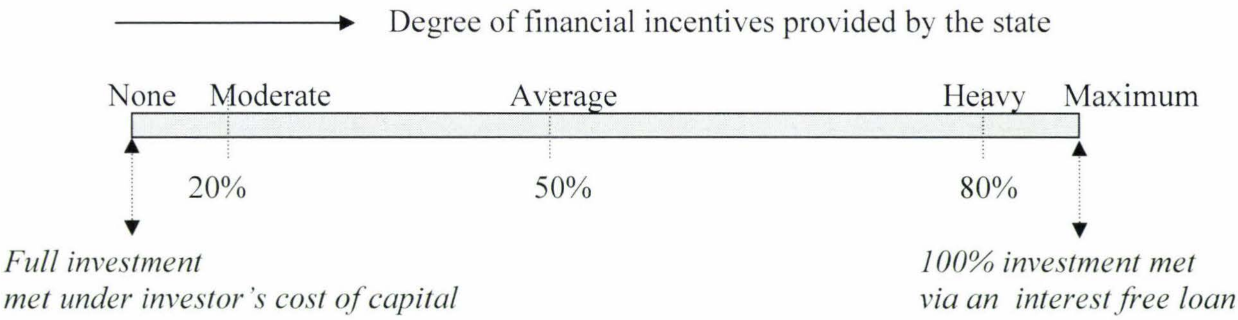

Fig. 8.1: The continuum of possible subsidy levels available for DG projects

In this analysis, for projects involving only renewable energy systems, the net present values were outputted under the two extreme cases; "no incentives" and "maximum incentives" so that any actual NPV would occur between these two extremes[1]. In the case of hybrids involving both renewable and non-renewable DG, it was assumed that the state provides subsidies for the renewable component of the project only.[2]

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1. *As mentioned in section 6.3.2, the computer model computes the applicable project discount rate taking into account the proportion of the capital provided by the state (and the interest rate charged), the balance capital required (and the investor's cost of capital) and the risk premium.*

2. *It can be argued that a carbon charge (or a similar tax) on thermal generators is analogous to a subsidy because taxes cause national electricity prices to move upwards, causing greater cash inflows for DG owners. However, at the present point in time, the cross elasticity of carbon tax on national electricity prices is not known and hence it was not considered.*

Detailed analyses were conducted for two scenarios: single farm ownership and community ownership as are discussed in sections 8.2 and 8.3.

8.2 THE SINGLE FARM BASED DISTRIBUTED GENERATION APPLICATIONS

According to the load data fed to the computer model (based on actual measurements for 6 months and inferred data for the balance 6 months as described in section 6.3.1), the annual energy consumption of a typical single farm amounts to 24,150 kWh. Features of the load profile included a summer mean load of 2.92 kW and a winter mean load of 2.58 kW. The corresponding half hour summer and winter peak loads were 14.10 kW and 9.82 kW respectively[3] while the corresponding median loads were 2.53 kW and 2.35 kW. The fact that the median load is smaller than the mean load suggests that the frequency distribution of the load is "positively skewed." The model also outputs the summer and winter load factors as 0.21 and 0.26 respectively.[4]

The above data leads into an interesting argument. If aggregate load metering is allowed, should the installed capacity of a farm supply be considered as 30 kVA because 30 kVA is the transformer capacity. The load research data suggests that reckoning a farm supply as 30 kVA may be unfair if net metering benefits are not to be extended to 30 kVA. According to the half hour load data generated by the *load worksheet* of the computer model, the peskiest half hour of a representative farm would only be 14.10 kW. Although probably a 30 kVA capacity transformer is still required for most farms, due to the instantaneous loads that may occur during any given half hour interval, the total time duration during which a farm load exceeds 14 kVA in a given year, would be extremely short. Thus in respect of a typical New Zealand beef and sheep farm, its electrical connection as aggregated at the transformer may be considered as a de facto 15 kVA connection for billing purposes. This is the capacity of a standard New Zealand domestic main for which net metering is usually allowed.

8.2.1 Wind energy projects

The financial viability of a wind turbine generator (WTG) projects based on the rated capacity, the metering option and the level of financial subsidy, as outputted by the

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[3] *Note that the seasonal peak load is not the average of daily peaks but the maximum of the daily peaks.*

[4] *It is important to note that the computer model is a stochastic analytical tool involving several random processes. Hence, the data outputted by the model can vary slightly from one simulation run to another, due to the very nature of the random processes.*

computer model is shown in Fig. 8.2. None of the combinations returned a zero or a positive NPV. However, considering the current 80% progress ratios shown for small WTGs (section 3.2.3), it becomes evident that locating a 7 kW wind turbine in a windy region (the annual average wind speeds equal or greater than 8.0 m/s) under a net metering regime backed by a well-subsidised scheme is the optimum option from an investor's perspective, because of the investor would be able to opt for the largest possible unit without additional financial burden, since the NPV remains static (at near zero) for WTG capacities up to about 7 kW.

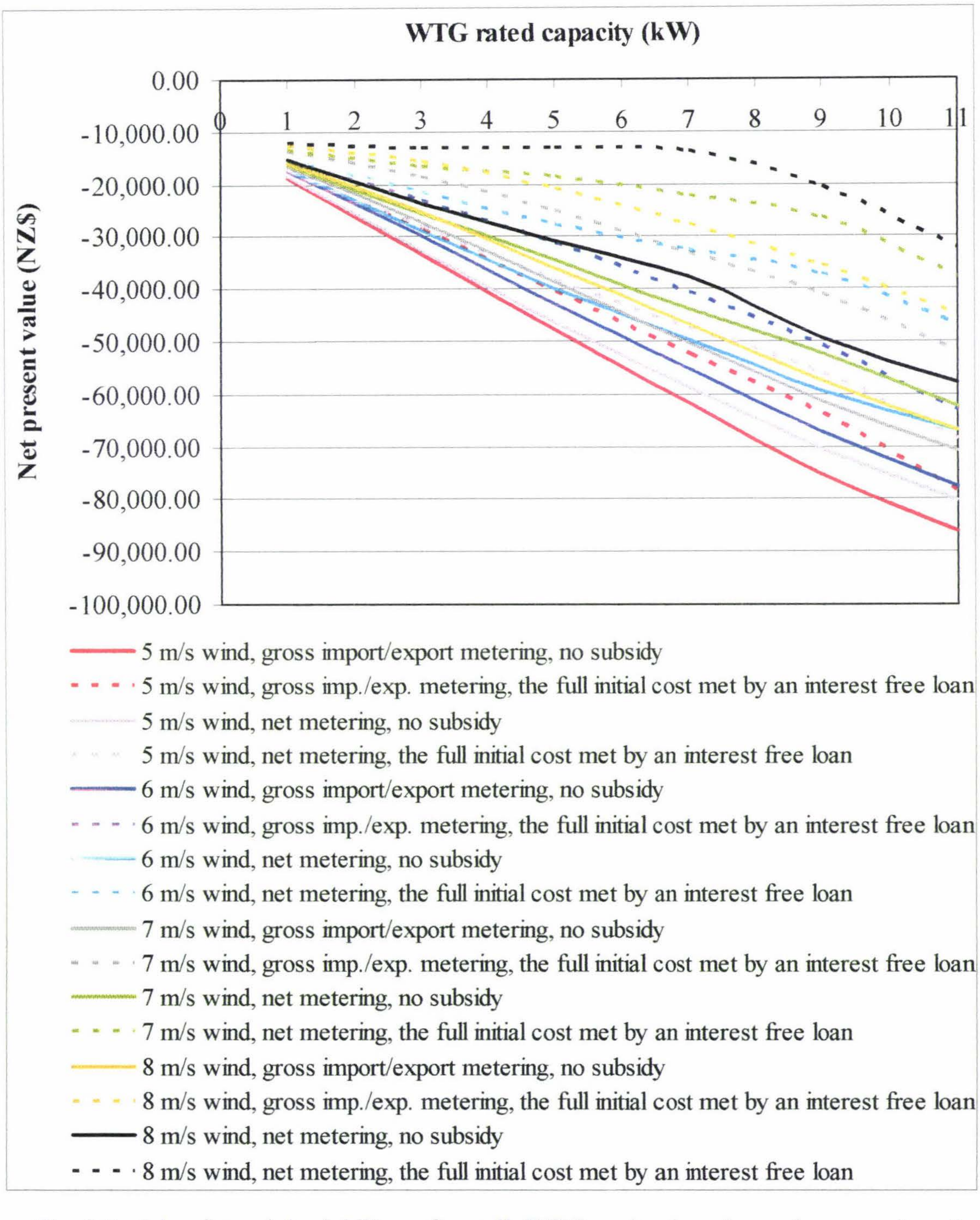

Fig. 8.2: The financial viability of small WTG units based on the capacity, the metering option and the level of financial subsidies

The financial benefit of net metering over TOU gross import/gross export metering is marginal for smaller WTG capacities (say < 3 kW) because the customer does not export any electricity to the grid under the latter metering option, as generation is less than load (at least for the most part). For higher WTG capacities (say between 3 kW to about 8 kW), the net metering outdoes the gross import/gross export metering. This is because in respect of net metering, for a given amount of generation, the revenue is realised by avoiding the retail charges only. In the case of gross import/gross export metering for the same amount of generation, the revenue is realised by avoiding part of the retail charges, with the balance coming from sale of excess energy to the retailer who purchases energy at a much lower rate than the retail charge. Beyond a certain capacity, depending on the annual mean wind speed, the net metering begins to loose its appeal because the WTG starts generating more energy than what is required by the farm for the billing year. Any such redundant quantity of energy is purchased at a lower rate by the retailer thereby reducing the marginal revenue.[5]

Breakeven WTG capacities for different site wind speeds at which total energy supplied by the DG system in a given year becomes equal to total energy consumed by the load during the same period were outputted by the computer model (Fig. 8.3).

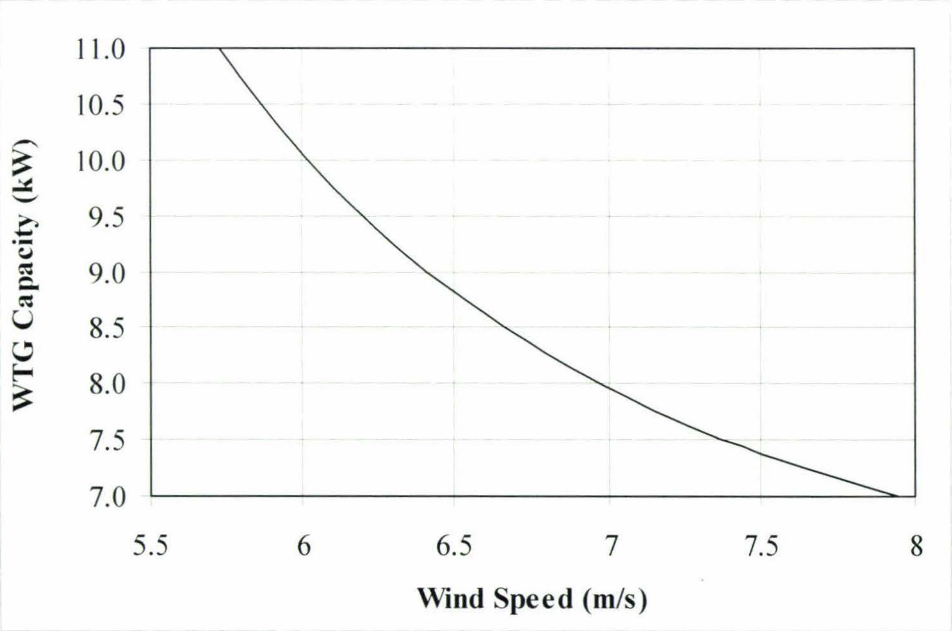

Fig. 8.3: The breakeven WTG capacities for different mean annual wind speeds

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[5] *As mentioned in section 6.2.6.1 (table 6.4 therein), the buyback rate for redundant energy would be at a rate approximately equal to the annual average spot price (4.0 c/kWh in the first year as per the computer model), which is substantially less than the retail price (11.6 c/kWh in the first year as per the computer model).*

It is clear from Fig. 8.2 that the level of subsidy available plays a major part in the financial viability of small wind projects. In order to analyse the effect of borrowing capital at zero interest rate further (which is analogous to a subsidy), a sensitivity analysis was made in respect of both a 3 kW and a 6 kW wind turbine generator with net metering under different levels of subsidies and assuming that only part of the capital would be met through an interest free loan, for a small wind energy project in a windy area (Fig.8.4).

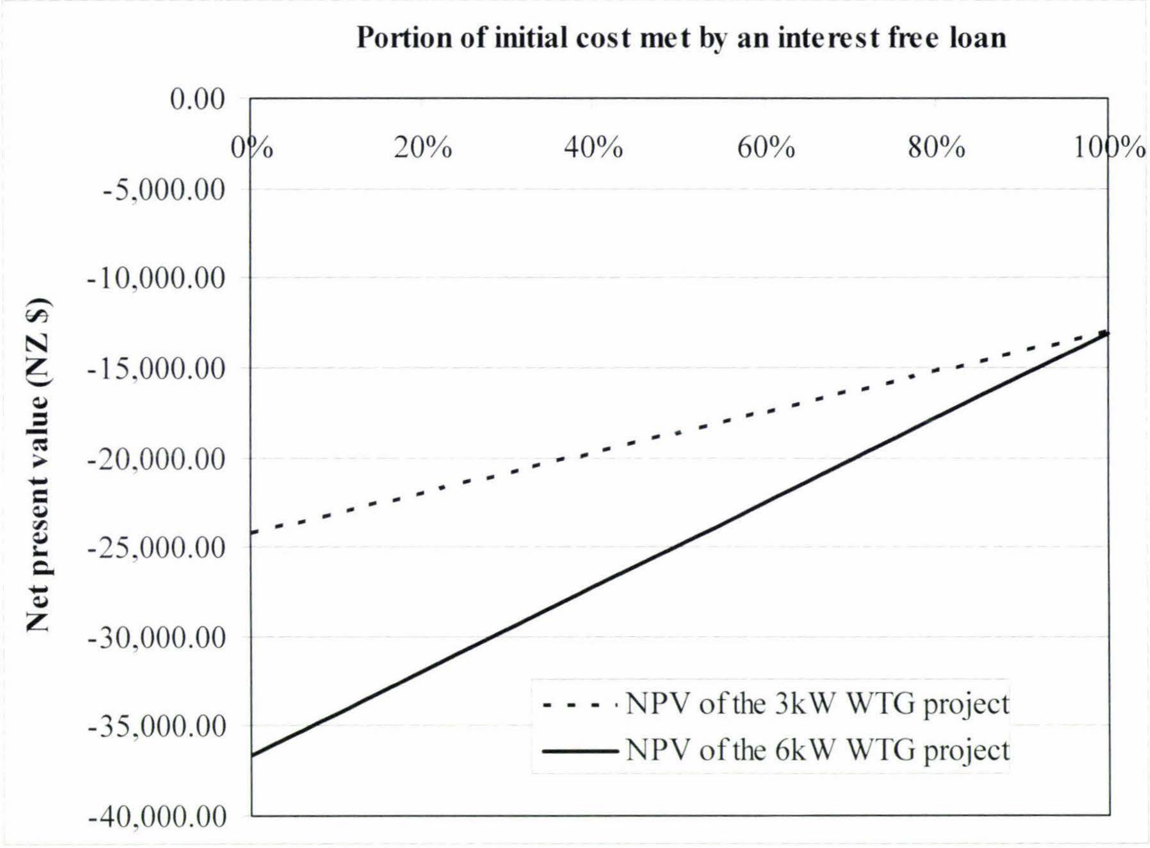

Fig. 8.4: The sensitivity of providing a subsidy for a small WTG project in an 8 m/s site under a net metering arrangement

It is clear that the NPV increases linearly with the percentage of funds borrowed at zero interest rate. It also confirms that from an investor's point of view, it is advantageous to opt for the higher capacity WTG unit (i.e. the 6 kW unit) under a very good wind regime, if funds could be borrowed at the lowest possible opportunity cost (i.e. zero interest rate). As the subsidies are increased, the NPV increases much faster to coincide with that of the smaller WTG.

The impact of line charges on the financial viability of small wind energy projects was analysed under two metering schemes at different annual average site wind speeds by varying the line charge rescale factors and wind speeds. As mentioned in section 6.2.6.1, the line charge rescale factor refers to the multiplication applied upon the existing line charge (6 c/kWh day charge and 4 c/kWh night charge as applied to the energy flows at the Woodville GXP). The results under net metering and gross import/gross export metering are shown in Figs. 8.5 and 8.6 respectively.

It is clear that even in a very windy area (8 m/s wind speed) under a net metering regime (the better option of the two from the investor's point of view) and without any subsidy to the investor, the lines company can raise its line charges, without causing the demand for electricity to diminish. This is because the NPV remains negative causing investors to look for other investment opportunities. However, the situation changes dramatically under a heavily subsidised scheme. For example under the maximum subsidy option (i.e. 100% initial cost met by an interest free loan), doubling line charges under a net metering regime would make NPV above zero even for a smaller WTG of 4 kW (see * on Fig. 8.5), meaning investors such as individual farmers would reckon investment in DG projects involving small wind turbine generators to be a very viable option.

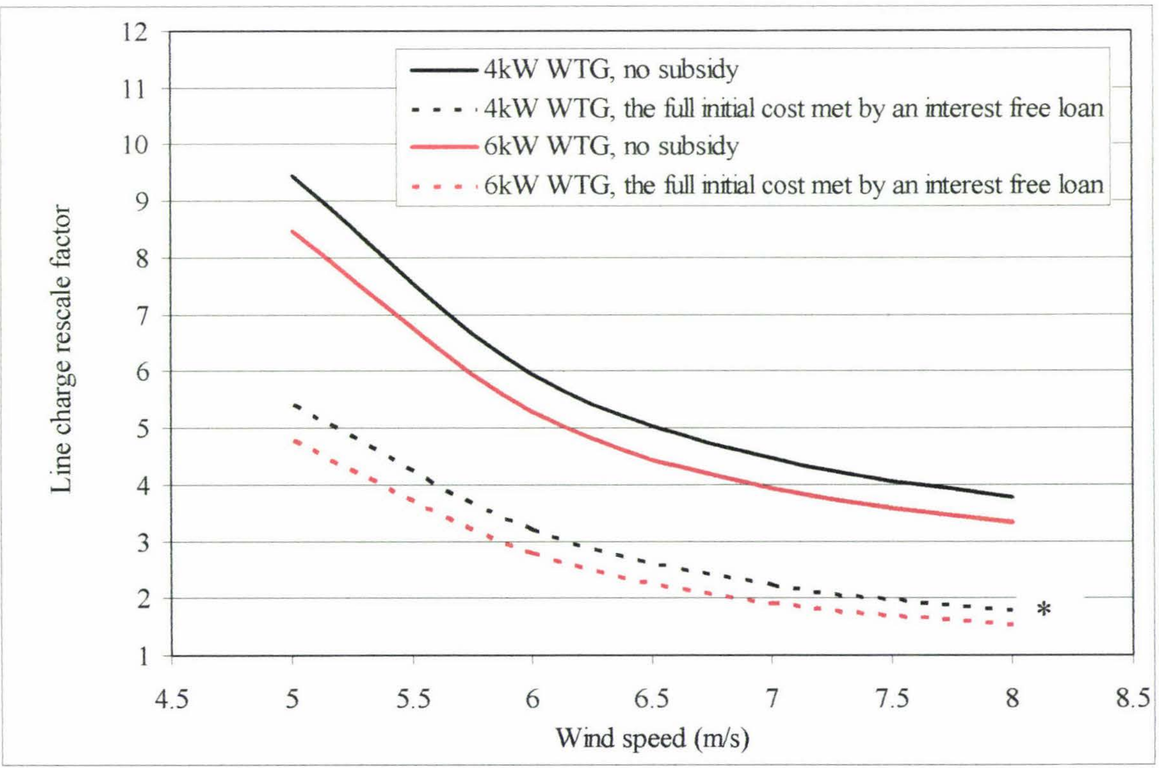

Fig. 8.5: The breakeven line charge rescale factors under a net metering regime that cause NPV zero under different wind regimes

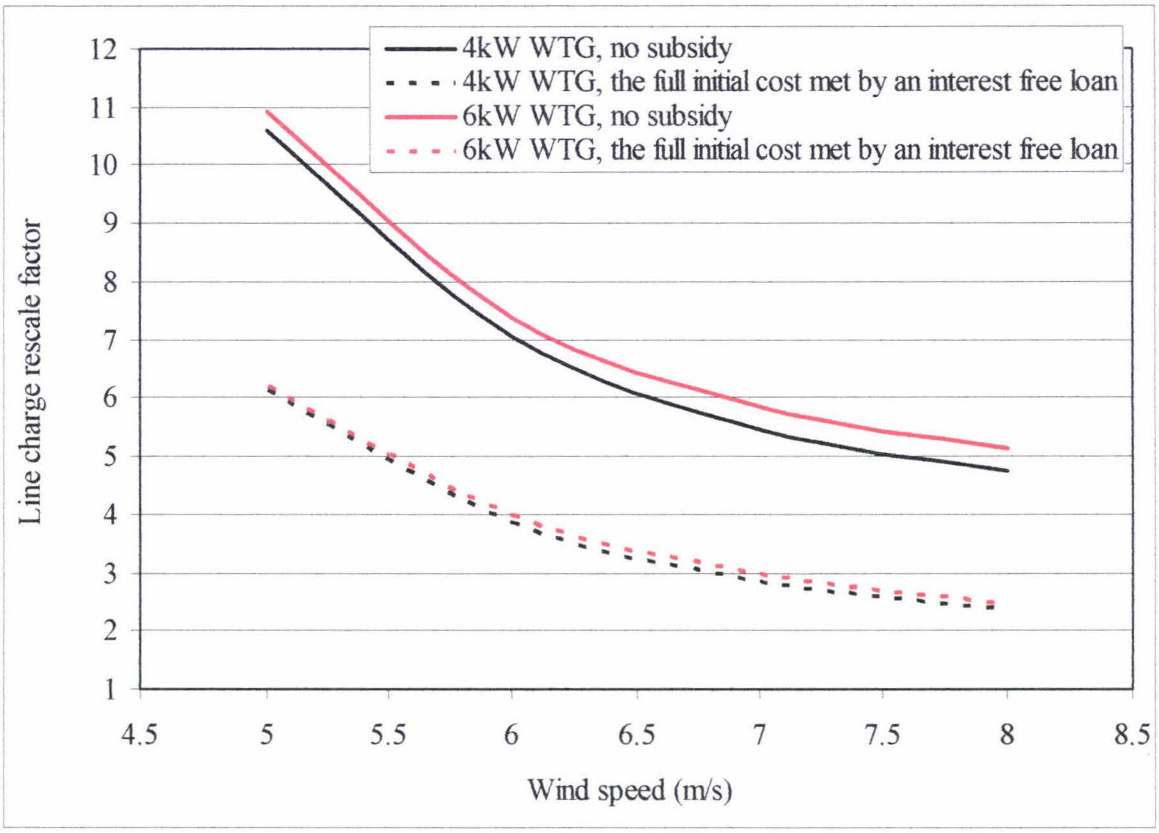

Fig. 8.6: The breakeven line charge rescale factors under a gross import/gross export metering regime that cause NPV zero under different wind regimes.

Figs. 8.7 and 8.8 depict the foregone revenue of the lines company under a net metering scheme and a gross import/gross export metering scheme respectively, under different site wind regimes with different WTG rated capacities. The results are based on current price structures applied to standard commercial customers and domestic customers (Appendix F) and assume no annual charges being levied on the DG investor for inter-connection.

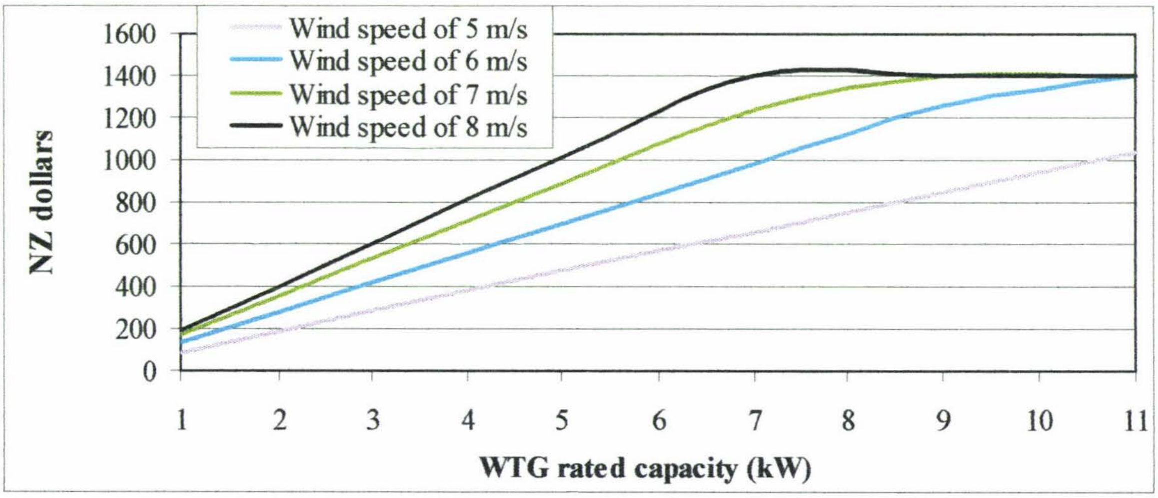

Fig. 8.7: The annual foregone revenue of a lines company under a net metering scheme for different WTG capacities installed under different wind regimes under existing pricing

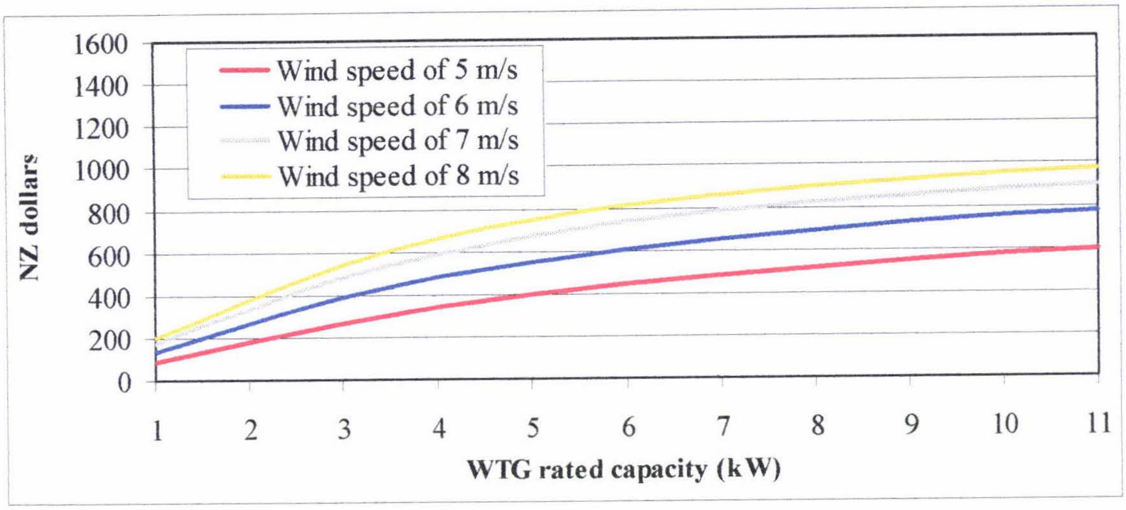

Fig. 8.8: The annual foregone revenue of a lines company under a gross import/gross export metering scheme for different WTG capacities installed under different wind regimes

It is evident from Figs. 8.7 and 8.8, net metering causes the lines company to lose more of its potential revenue especially in windy areas, compared to gross import/gross export metering. Under net metering, for a given wind speed, as the WTG capacity is increased and becomes large enough to supply the entire energy requirement of the farm (for a given billing year) the lines company looses all of its potential revenue that would have been otherwise charged for energy sales.[6]

A lines company can reduce the possibility of losing excessive revenue by altering its line charge tariff structure. For example, it can reduce the energy based line charges (i.e. c/kWh) substantially and recover from its customers whatever additional revenue it requires to meet its required rate of return on its assets (with or without DG) by some other criteria. One such criterion is to charge the customers mostly based on critical peak periods so that what the customer avoids as energy based line charges is minimised. This however means that the financial viability small WTG is further affected. However, comparison of the simulation results on a 6kW WTG under the pricing structure administered by Orion New Zealand Limited, which charge customers partly based on critical peak periods (Orion, 2003), with the pricing the structure administered by ScanPower, showed that there is no significant disadvantage to the small wind investor under critical peak period pricing, provided proper metering equipment is installed to record peak period contribution of the WTG for capacity support (section Q.2 of Appendix Q). These results also show that WTGs actually provide some capacity to the network during critical peak periods.

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[6] *See row 1 of Table 6.3 (Chapter 6) for a clearer understanding.*

If a lines company invests in DG technology in a property leased out by a private landowner, then the private landowner benefits from the lease agreement (assuming that DG is the most profitable way to use the land). The model can be used for any investor including a lines company. If the investor is the lines company, the only change the user has to make is to ignore the "annual charges for connection/grid injection" suggested by the model (row 7 of Table M.11 in pages M-23 and M-24) and force that value to be equal to "the annual payment the company makes to the land owners". Also unfortunately a higher discount rate (say 10%) has to be used if the investor is a lines company (especially if private owned).

Depending on the NPV (assuming say a 10% cost of capital and 0% project risk premium) a lines company may or may not benefit from the investment. Simulation results show that if the primary purpose of the DG investment is to supply firm capacity and the technology used is diesel generation and the capacity of the investment is large (> 230 kW as shown in Fig. 8.20) then there is a clear economic benefit to a lines company in making the DG investment.

Of course, the above results are based on the existing technology. With technological advancements in the future one may have a wider DG technological options at his or her disposal.

The effect of a state subsidy in the form of a low interest loan is that it makes a DG investor's cost of capital (and hence the discount rate) go down considerably. This is a key driving force for achieving a higher NPV (also see the explanation given opposite Fig. 8.24). However, state support is not justified for non-renewable energy projects.

In putting all of the above observations in to context, it can be said that a state subsidy would greatly enhance the viability of a small WTG project. However, notwithstanding the fact that wind is a clean energy source and hence small WTG generation needs to be encouraged, the state can be assumed to have several equally important priorities in utilising its tax revenue for the economic and social wellbeing of its citizens. These aspects are covered in section 9.

It is also evident that even with a reasonable subsidy, only a limited number of electricity users would opt for small wind projects due to competitive energy and line tariffs coupled with high technology costs. Hence, in the short run, it is highly unlikely that a lines company would be affected by DG involving small wind energy projects, even under net metering. A lines company can always increase its charges for inter-connection (or introduce inter-connection charges if it is not doing so) when it finds that connecting further DG does become a threat to its revenue. Exempting today's small wind investors from such charges would serve as a means of rewarding the risk takers in the society, the ones who are willing to embrace new technology and the ones who have a greater concern for the environment.

8.2.2 Photovoltaic projects

Simulations on photovoltaic (PV) projects show that it is not as encouraging as wind projects, based on the current state of technology (i.e. initial cost and operational performance). A sensitivity analysis made on the generation performance and the economics of PV projects based on installed capacity is shown in Fig. 8.9. Section Q. 3 of Appendix Q provides the simulation output containing project details for a 500Wp PV project. Note that according to the computer model, the Totara Valley annual average daily solar radiation is 3.9 peak sun hours (PSH) on a horizontal plane, which is a low overall sunshine level.

There is no optimum PV installed capacity because the NPV remains negative and deteriorates steadily as the capacity increases, even under a well subsidised incentive scheme (Fig. 8.9).

The reason for the poor financial performance is the relatively poor generating capability of PV modules, for which the low available solar irradiation is also partly accountable. For comparison, according to the computer model, a grid connected 3kWp PV system with a net metering arrangement costs $ 40,640 but produces as little as 4290 kWh per annum, whereas a 3 kW grid connected WTG which also happen to cost approximately the same amount, produces as much as 7923 kWh (85% more than PV), in only a 6.0 m/s wind regime. Under these circumstances, PV is unlikely to pose a major concern to a lines company.

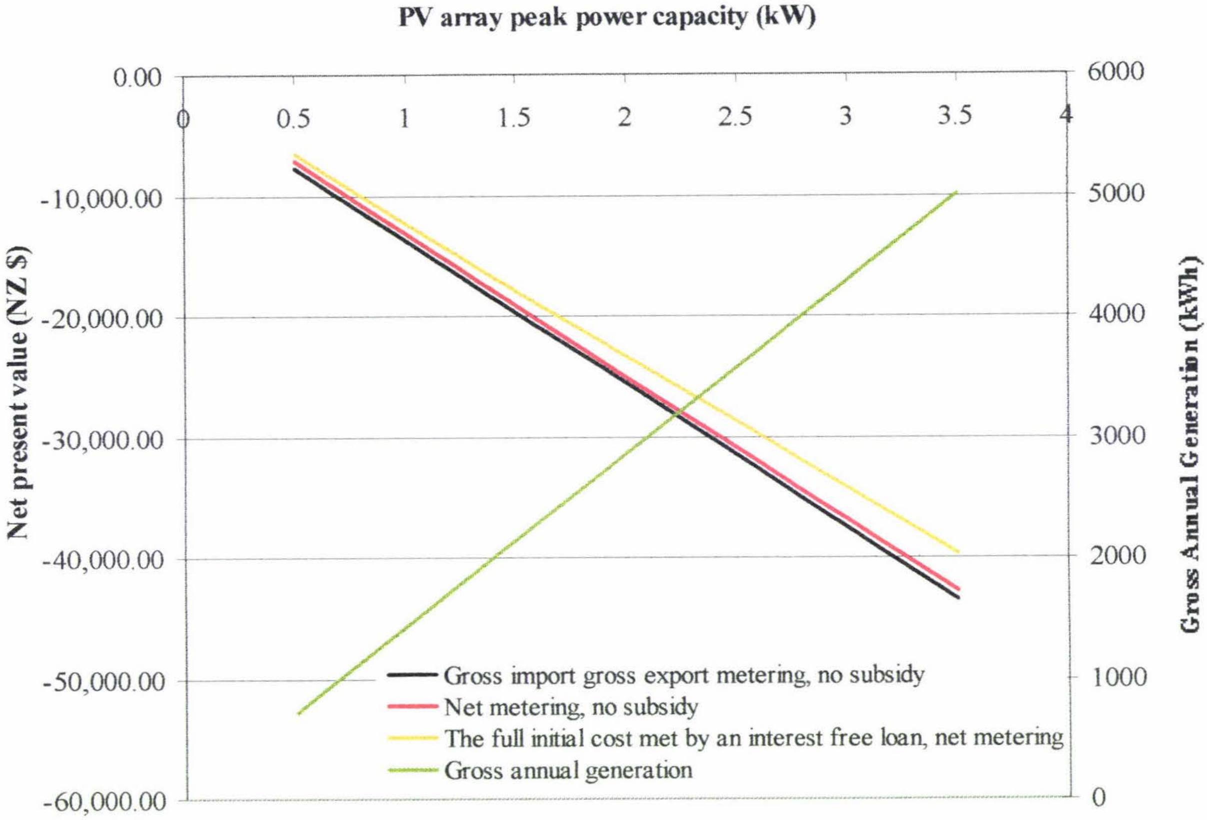

Fig. 8.9: The gross generation capacity and the net present value of PV projects

8.2.3 Micro hydro projects

The financial viability of two micro hydro (MH) projects based on the metering option and the level of financial subsidy, as outputted by the computer model under no subsidy and maximum subsidy are shown in Figs. 8.10 and 8.11 respectively. The rated capacity of the MH units under the assumed flow pattern (Fig. 8.12) was 6.5 kW according to the computer model. According to the computer model, this is the power output of a MH unit that would operate at a gross head of 13.5m for the annual average flow rate of the water stream (after allowing for a 10% flow bypass, hydraulic losses and efficiencies of electro mechanical equipment).

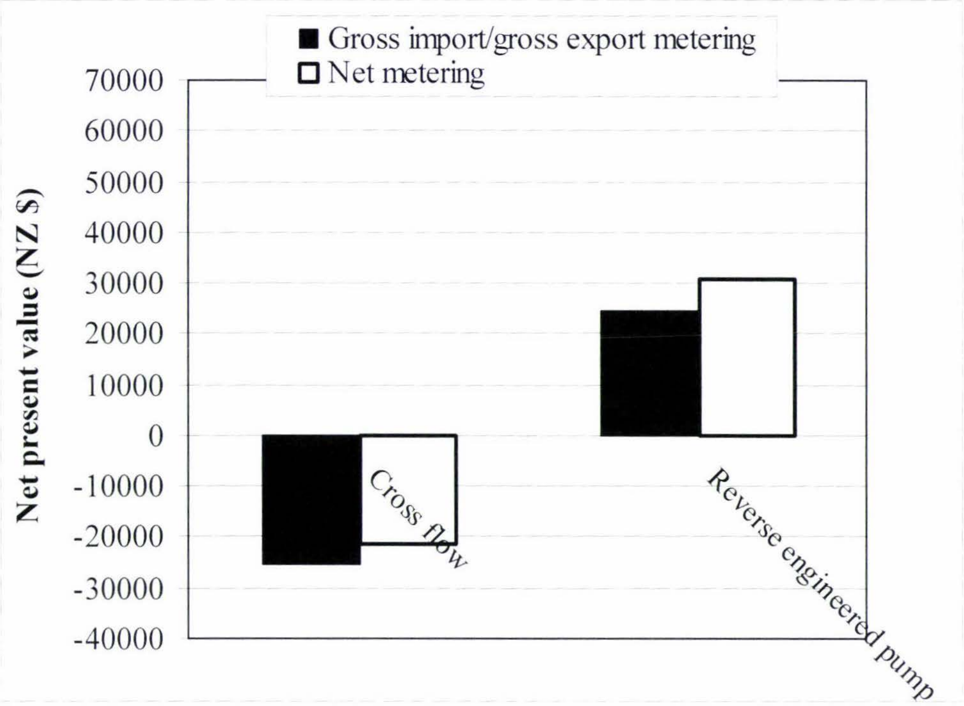

Fig. 8.10: The financial viability of two different MH technologies with no subsidy

It is evident that the reversed engineered pump, which is essentially a low cost MH option, is the most financially viable option for which no subsidy is necessary to make the project viable (Section Q.4 of Appendix Q provides details). In the case of cross flow technology, [7] the financial viability becomes largely contingent on the level of subsidy provided. An important generalisation that could be made in regard to provision of subsidies for renewable energy projects is that it is equally important for the state to use its agents such as the research institutions to discover the appropriate technologies and educate the citizens as much as providing the necessary subsidies for small renewable energy projects. The MH example clearly indicates that appropriate technologies can circumvent having to provide subsidies (Section 9 provides details).

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7. *Note that the standard method of inter-connecting a micro hydro generator (especially a one of the order of 6.5 kW) to the grid is through an inverter (after rectifying the alternator AC output) as depicted in Fig. L.1 of Appendix L. The model assumes that this is the only way a micro hydro unit is inter-connected to the grid, unless otherwise it is a low cost micro hydro unit, which among other low cost features includes an induction generator, which circumvents expensive power conditioning devices such as inverters. It is technically possible to use an induction generator for a cross flow turbine and hence reduce the project's capital to some extent.*

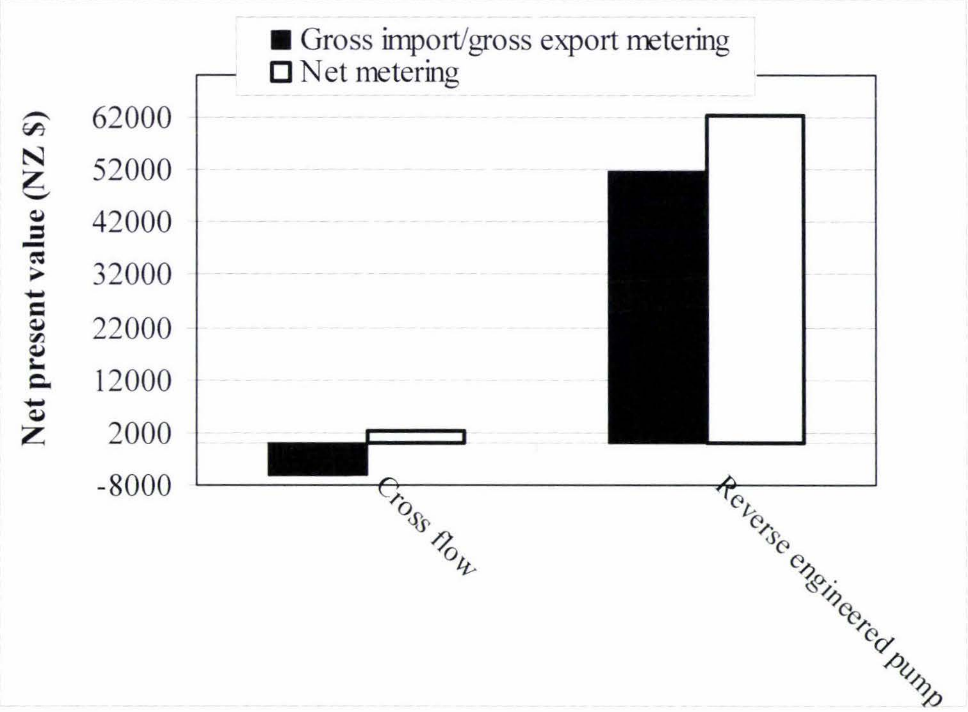

Fig. 8.11: The financial viability of two different MH technologies with full project investment met via an interest free loan

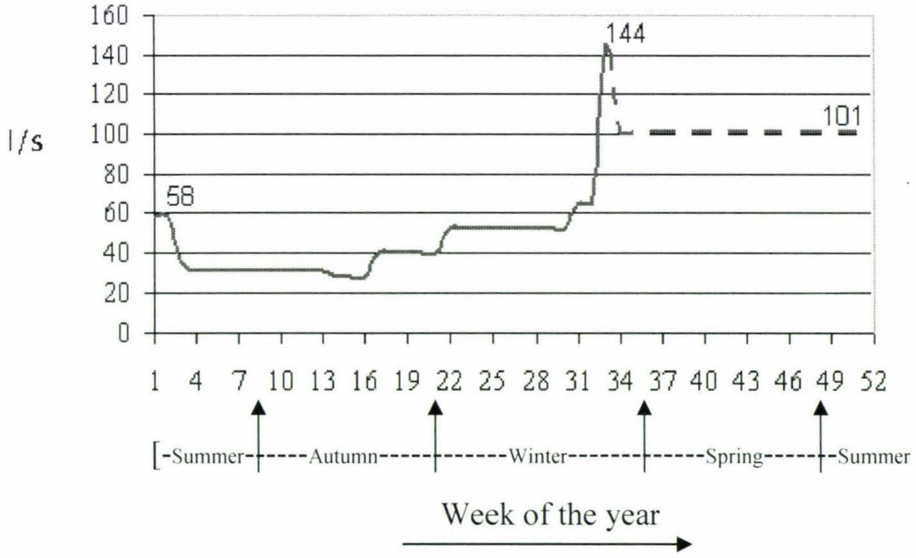

Fig. 8.12: The water flow rate of the Totara stream used for the simulation *(Irving, 2000)*

There are two main reasons why a low cost MH option is economically more viable than other technology options.

- Simplicity of the interface: A low cost MH unit does not require an inverter for it be connected to the grid. This is because a low cost MH unit employs an induction generator (i.e. the induction motor of a standard pump operating as a generator) which could be hooked to the grid directly. The cost of the inverter and the associated inter-connection costs in respect of other technologies amounts to nearly 1/3 of the total initial investment on grid connected MH projects (Fig. Q2 of Appendix Q, section Q4).

- Simplicity of the electro mechanicals: The low cost MH is an extremely simplified electro mechanical configuration as a centrifugal water pump is used in reversed flow direction (i.e. the pump outlet becoming the inlet of the MH unit and vice versa). In such a configuration there is no need for mechanical control gear such as governors, wicket gates, nozzles and electrical gear such as rectifiers (to convert the AC produced in the generator into DC), which all add to a project's initial cost.

The low initial cost plus steady stream of cash inflows (which is also common for other MH technologies as well, due to the steady flow of water through the turbines) means that a low cost 6.5 kW MH project is able to payback its initial investment in 4 years (section Q4 of Appendix Q).

From a lines company's point of view, the technology of the MH unit does not become a factor that affects its revenue losses because the energy injected to the grid is approximately the same in all the technologies.[8,9] The simulations also show that under a net metering regime, the lines company looses the maximum possible revenue (i.e. NZ$ 1,400.00 approx. as mentioned in section 8.2.1) because the total annual gross generation of 41,359 kWh exceeds the total annual electricity demand of the farm which is 24,150 kWh. Under a gross import/gross import metering regime, the line company is able

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[8] *As mentioned in section 6.2.8.1 the induction generators absorb reactive power (not real power) from the grid to magnetise its electric fields. For small generators such as 6.5 kW units it is unlikely that ScanPower would stipulate to install any reactive power compensation equipment such as capacitors.*

[9] *An induction generator is slightly less efficient than a conventional alternator (used in Pelton and cross flow technologies). However, the low cost MH option (i.e. the reverse rump) which involves an induction generator more than compensates for the lower generator efficiency because there is no rectification and inversion involved (hence energy losses), as in the case of the other two options. Therefore, the reverse pump would in fact provide a fractionally higher energy quantum than any of the other two MH units.*

to salvage about NZ$ 100.00 from the maximum possible foregone revenue due to low hydro flows in the first four months of the year (Fig. 8.12). However, since the number of small water streams that could be harnessed is limited, it is unlikely that small micro hydro projects would become a major concern to the lines companies.

Since the estimated hydro flows for the period between 12 August to 31 December was derived by averaging the flows corresponding to the last day and the first day on which the data was collected (section 6.3.1) and this averaging process may have lead to an excessive flow rate, as suggested by Fig. 8.12, the Totara stream flows for the above period was lowered to 40 litres/s and the simulations were re-run. The new results show a similar pattern (Figs. Q3 and Q4 in Appendix Q, section Q5) to those discussed already, except for the fact that the designed capacity of the MH unit is lowered to 4.5kW by the computer model, due to reduced average flow rates (Fig. Q5).

8.2.4 Projects involving standby diesel generators and wind-diesel hybrids

Simulations show that operation of a small standby diesel generator during the farm evening load peaks, purely to offset the energy drawn from the grid, is extremely uneconomical, based on existing line charges and energy tariffs (Fig. 8.13). This is in spite of treating the retail price of electricity in the model under gross import/gross export metering as a variable proportional to spot price of energy, which usually becomes higher in the evening peaks on account of higher national aggregate energy demand.

However, cash inflows increase rapidly when the diesel generator set operates under critical winter peaks signalled by the lines company (Fig. 8.15). This is due to receipt of cash for the firm capacity provided, from the lines company. The cash receipts for supply of firm capacity are significantly higher than cash receipts for saving of grid energy and supply of energy to the retailer. In spite of this the NPV remains negative (Fig. 8.14),[10] meaning that investing in a brand new small standby diesel generator set, a rectifier and an inverter to inject firm capacity to take advantage of the lines company price signal is not economic.

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[10] *Note that results under net metering were nearly identical to results under gross import/gross export metering shown in Figs. 8.14 and 8.15.*

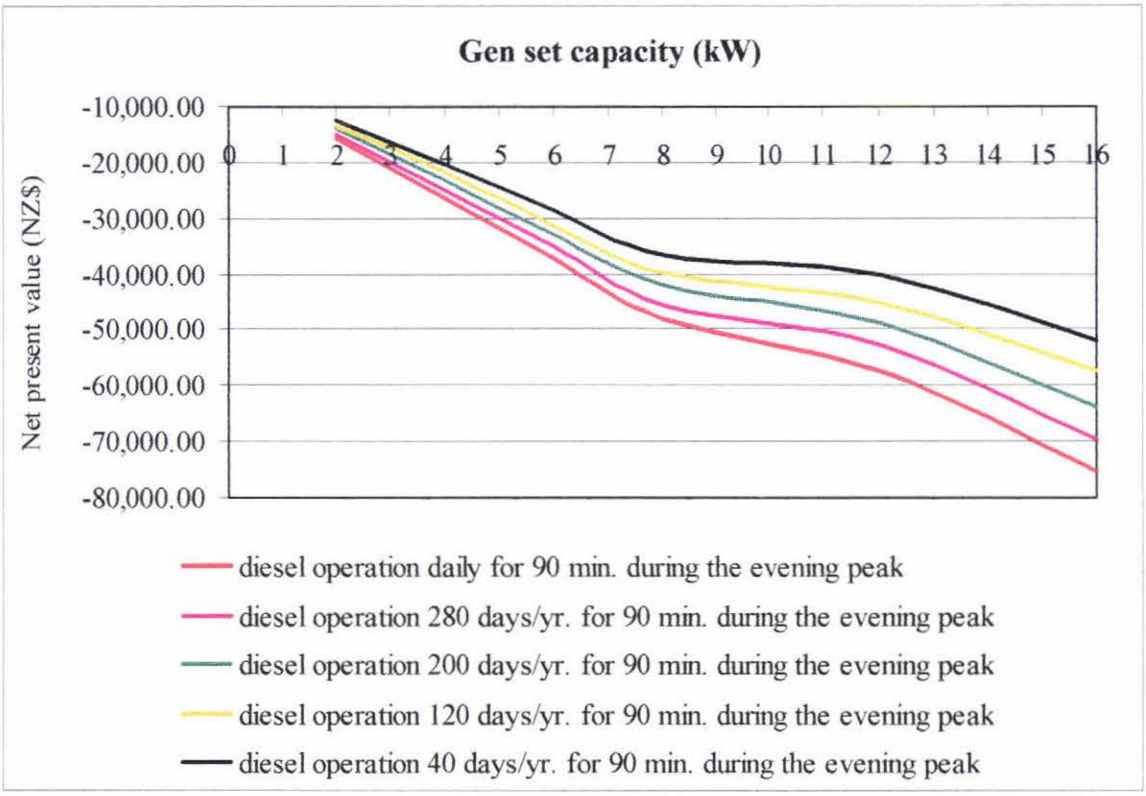

Fig. 8.13: The financial viability of a small standby diesel generator operating during the evening load peaks to offset energy drawn by the farm supply under gross import gross export metering[11]

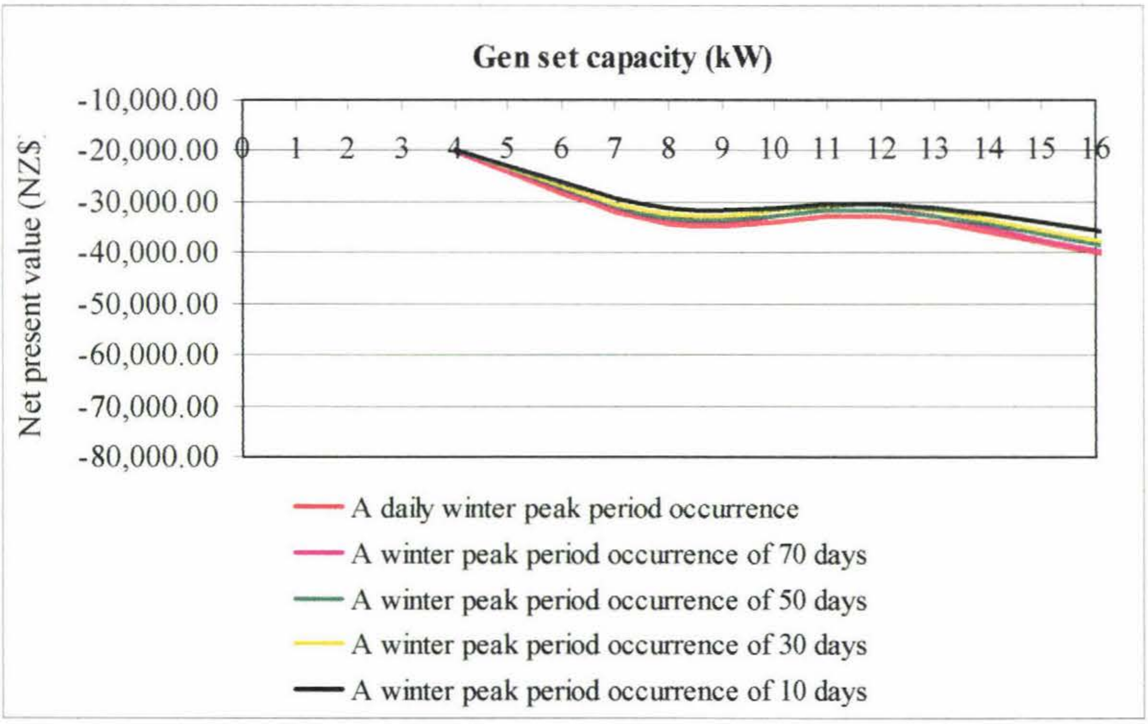

Fig. 8.14: The financial viability of a small standby diesel generator operating as a demand side response to winter peaks signalled by the lines company under gross import/gross export metering[11]

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[11] *The slope of the curves tends to flatten out around the 10kW mark, mainly due to the algorithm pertaining to prediction of the inverter costs. There is a step change in the inverter cost at the 10kW mark (Table M.10 of Appendix M), where the unit cost of the inverter suddenly drops to some extent, according to the only quotation that was available for inverters ≥ 10kW. This however is not a major observation because NPV remains negative and downward sloping at all times.*

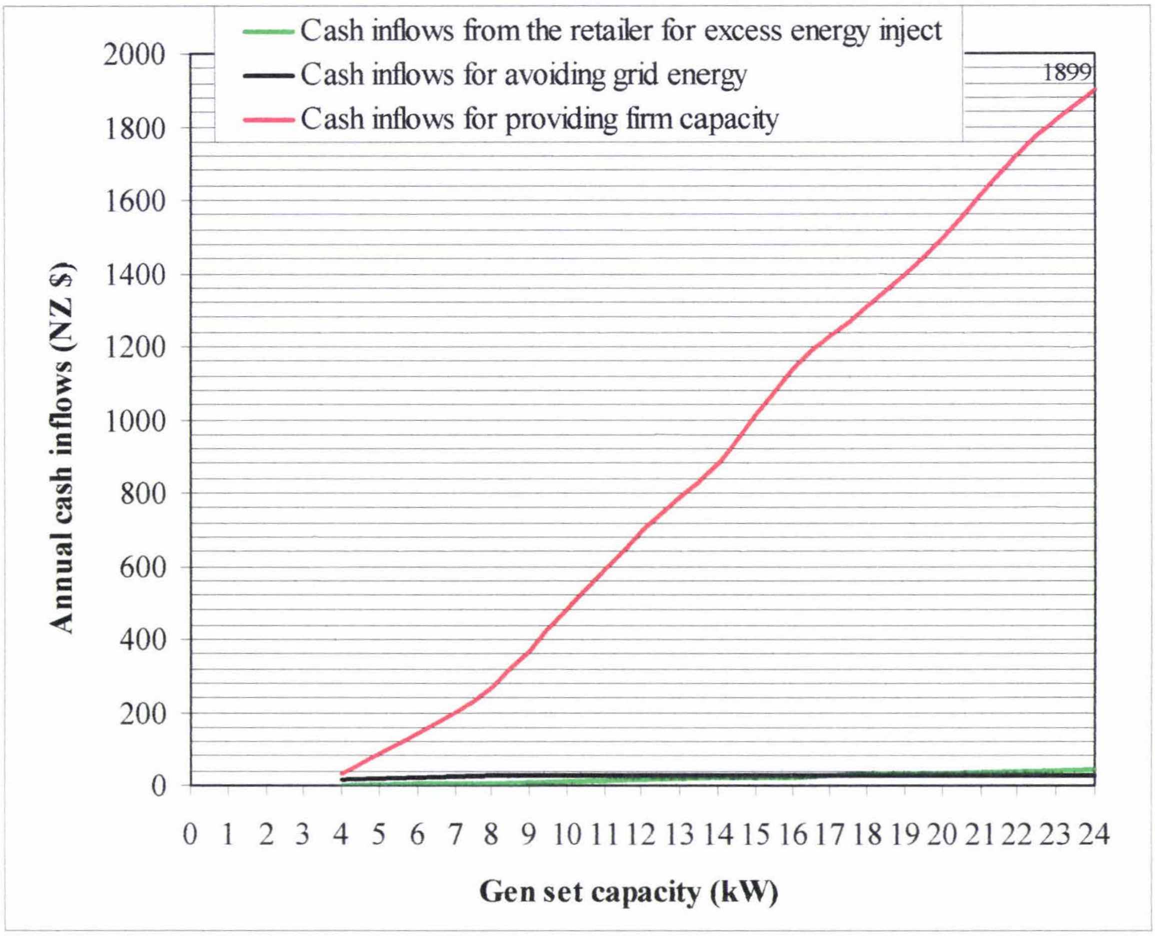

Fig. 8.15: Annual cash inflows from a small standby diesel generator operating as a demand side response to one hour winter peaks signalled by the lines company for 50 days under gross import/gross export metering

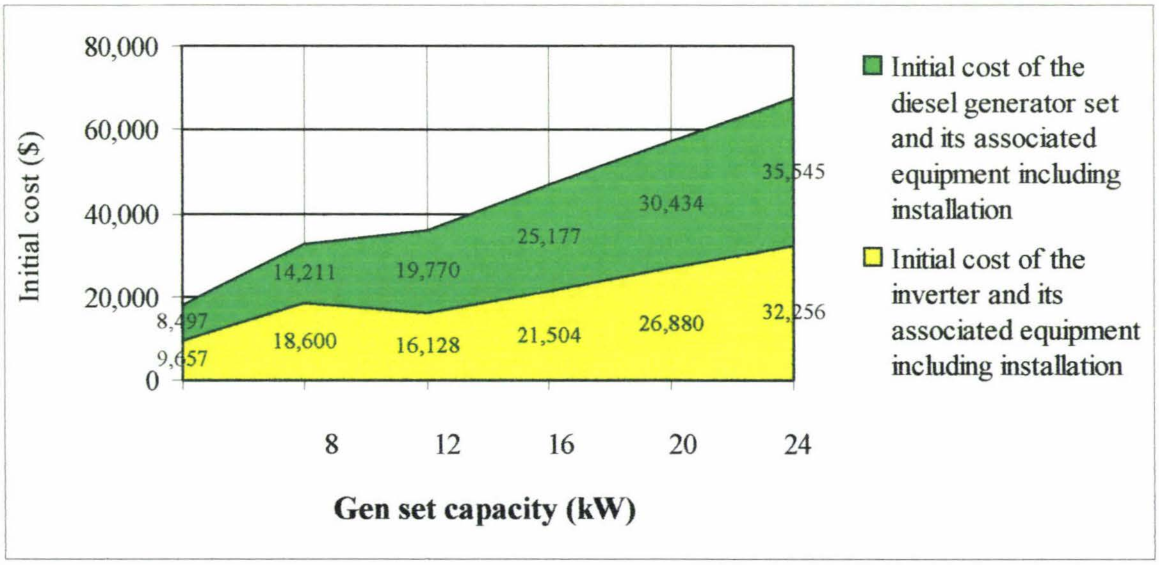

Fig. 8.16: The initial cost structure of a small grid connected diesel standby generating unit

There are three main reasons why the investor does not receive sufficient net cash inflows to overcome the initial investment and cause NPV to be positive as follows.

- The high cost of the inverter and its associated equipment constitutes a significant proportion of the initial cost (Fig. 8.16).
- Rectifying near grid quality AC supply of the standby generator and then inverting amounts to a power loss for which no moneys are received. According to the computer model, a 18 kW standby generator operating at full load would inject 16 kW only due to rectifier and the inverter power losses.[12] Hence the investor foregoes a cash income of NZ $ 240.00 from the lines company [being 120*(18-16)] each year. This amounts to lowering of the NPV by NZ$ 1843.00 (at 5% discount rate).
- Supplying firm capacity to the grid through the customer load in the eyes of the lines company, would be viewed as injecting capacity net of customer's load. Hence, a lower capacity payment would be made to the investor.[13]

One easy way to overcome the first two problems is to use an induction generator (which is nothing more than a standard induction machine that back feeds energy when driven by a prime mover in the same direction as the motor) as the generating source and a diesel engine as the prime mover. Because the total number of hours the diesel generator has to operate for supplying firm capacity is small, it pays for an investor to purchase a used diesel engine and a matching motor (to be used as a generator) and directly connect the

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[12] *At full load the rectifier and the inverter would function at 95% and 93% efficiencies respectively and hence 18 kW power output at the generator terminal reduces to 15.9 kW at the inverter output.*

[13] *It could be argued that, in spite of a DG unit being connected behind the customer's load tariff meter, the customer should be credited for the full amount of capacity produced at the customer mains, because this capacity should otherwise have to be provided by the lines company. There are three debatable points in this argument. Firstly, international experience shows that utilities always consider a small-DG owners connected behind the customer's load tariff meter as a negative load and not as a generator (Roche, 2001). It is treated analogous to any other demand side measure to offset loads (e.g. solar hot water, energy efficiency lighting etc.). Secondly, the physical legal interface between the customer's assets and utility's assets by definition is the customer's tariff meter. It thus implies that what is important is what is seen at the interface point and not elsewhere. Finally lines companies such as Orion NZ Limited, who actually reward DG owners for supplying firm capacity, price their line tariffs based on load during critical peak periods, which takes into account customer loads whether directly metered or not. Hence, on paper, a net-metered customer or a gross import/gross export metered customer is deemed to have been rewarded for lowering or eliminating his or her load during critical peak periods through DG. Hence, a lines company can argue that firm capacity should be net of customer load to avoid double counting it. In practice however the reduction or total elimination of peak period charge is realised only if the customer load is physically metered separately during the period concerned (meter IV in the metering configurations depicted in Fig.6.11a and 6.11b).*

motor to the grid with minor modifications to the control system. As an example, a 16 kW diesel engine-induction motor arrangement can be installed for a cost of NZ$ 9,500.00 and is capable of delivering the same capacity as that provided by a 18 kW standby generator-rectifier-inverter arrangement costing NZ$ 53,500.00 (Fig. 8.16). This saves at least NZ$ 44,000.00 of initial capital. Since the NPV corresponding to an 18kW standby generator-rectifier-inverter system used for providing capacity ranges between minus NZ$ 39,000.00 and minus NZ$ 43,000.00, depending on the nature of the peaking scenario (Fig. 8.14), the NPV corresponding to the diesel engine-induction motor configuration becomes positive, resulting in financial viability (Fig. Q8 of Appendix Q, section Q6 provides further details).

The most straightforward way of circumventing generation capacity net of customer's load, is to come with an agreement with the lines company and the incumbent energy retailer to reward the DG owner for firm capacity provided, based on a meter on the generation leg. An alternative but a dubious way is to come with an agreement with the lines company and the incumbent energy retailer to bill part of the line charges based on a separate meter at the grid leg based on capacity drawn and capacity supplied during critical peaks. This may require overhauling the existing price structure for a lines company that do not base its product price on capacity drawn during critical peak periods (e.g. ScanPower). A lines company can take the hardware costs and overheads associated with additional meters into account in setting tariffs for rewarding DG owners (section 6.3.3).

Since the net present value of a small wind energy project is invariably negative, even with a level of state subsidies and payments from lines companies for firm capacity, a rational investor will not undertake investing in a wind turbine to constitute a wind/diesel hybrid system, according to mainstream economic thought. This is because the NPV of any wind/diesel hybrid system would be less than the NPV of a diesel generator system. This was verified by simulating some conventional wind/diesel hybrids and low cost versions operating under best possible scenarios (Figs. Q.6 and Q.8, Appendix Q, section Q6). Accordingly, from a mainstream economist's viewpoint, customers served by lines companies that are providing incentives for firm capacity will end up connecting low cost diesel generator solutions only, notwithstanding potentially good renewable energy resources (Fig. Q.8, Appendix Q). The state, which has a direct interest on utilisation of clean energy sources, has to devise strategies to circumvent such situations.

The first paragraph of section 8.3 (page 192) is further explained as follows.

The model considers situations where distributed generation (DG) being greater than the community load (section 8.3.2), where relevant. For systems where generation is separately metered and considered as a separate entity by a utility, the parameter "community load" does not enter as a variable in the decision model because the designated task of the DG system is supplying energy and capacity to the grid. In these systems the owners derive revenue entirely from selling energy and capacity to the grid. The latter, only if critical peak periods exit.

Assuming other things remaining constant, the economic viability of DG systems whose generation is separately metered (and considered as a separate entity by a utility) is affected not by the size of the community but by the size of the DG units. For example, assuming that access to capital is not restricted, it does not make any difference to the economic viability whether a 500 kW wind turbine is owned by a single owner or a large community, so long as the generation is separately metered and considered as a separate entity by a utility.

8.3 COMMUNITY OWNED DISTRIBUTED GENERATION SYSTEMS

In the case of community owned DG schemes that are separately metered for generation (i.e. grid injection), the size of the community and its load profile have no direct bearing on the economic viability of the project. For this reason, the results of separately metered DG systems for Totara Valley Zones B and C are shown concurrently (Figs. 8.18 through 8.22).

However, the community size has an indirect bearing on the viability of a DG project due to the following reasons.[14]

- Larger communities have a comparative advantage in utilising distributed renewable energy because there is a better chance of finding better locations (e.g. sites with higher average wind speeds, better terrain for micro hydro etc.).

- Larger communities can raise a higher capital that will pave the way to implement larger renewable energy schemes that yield better returns.

- Larger communities can establish community organisations that can borrow funds at a lower opportunity cost.

- Larger community organizations can also take advantage of division of labour (e.g. afford to use the services of a specialist when required).

- Larger community organizations can attract state attention due to greater social benefits and hence the possibility of receiving subsidies which an individual member of the society cannot expect to receive (e.g. tax concessions, import duty concessions or even outright waivers for renewable projects).

- Larger communities can afford to reduce line charges on energy drawn (hence an additional cash receipt) by investing in additional independent load control hardware that shed certain loads when line capacity is constrained.[15]

- Larger community organizations have a better bargaining strength that becomes an important factor in negotiating contracts with utility companies on tariffs for buying and selling of electricity.

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[14] *Note that these reasons are not mutually exclusive.*

[15] *Note that the computer model can be used to study the effect of customer initiated load control.*

It is also important to note that the impact of grid injection on power quality is ignored in this study as the computer model considers a distribution line as an infinite sink (Appendix P). In practice, there may be some restrictions on the amount of power flow allowed through a 11kV feeder and/or certain conditions may be imposed by the lines company such as having to have fast response line compensation devices to minimise such effects as voltage flicker.

8.3.1 Separately metered community owned distributed generation systems

Fig. 8.17 illustrates a community owned DG system whose generation and loads are metered separately. It is important to note that for a community DG system (whether generation is metered separately or not), it is not necessary for the grid in-feed to take place at the beginning of the community boundary (i.e. Zone B or Zone C in the Kumeroa context, Fig. 5.1). The generation in feed should ideally be at a location where the generation could be dispatched to the grid at the lowest possible cost. Note that the controllable (dispatchable) generation source shown in Fig. 8.17 only responds to a ripple control signal transmitted by the lines company during critical peak periods. It was assumed that Kumeroa and Totara Valley communities have insufficient load that could be switched off during the critical peak periods (other than that already controlled by the lines company). Hence, the computer model was not used to study the effect of load control.

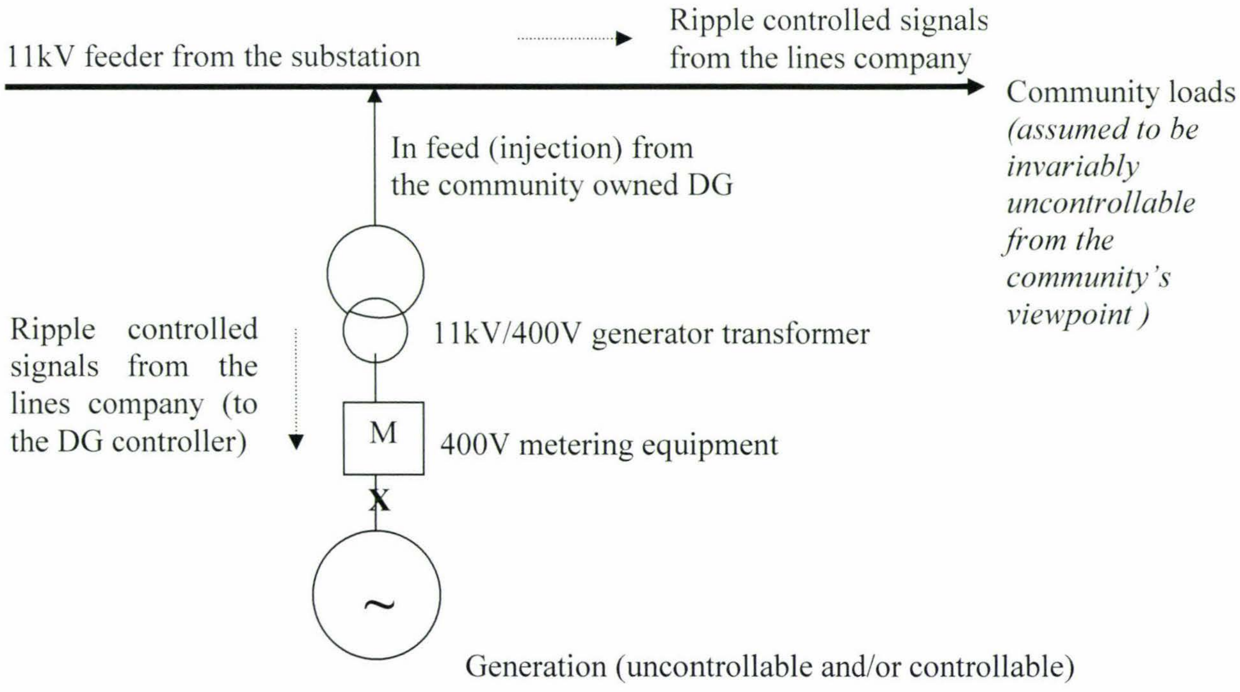

Fig. 8.17: The configuration of a community owned, separately metered DG system

8.3.1.1 Wind energy projects

The financial viability of a medium scale wind energy project operating as a self-contained generator is shown in Fig. 8.18. Note that sales revenue of the project is realised through energy sales only. All WTG simulation runs were made on the assumption that the lines company does not charge a fee for injection. Any fee based on the installed capacity or such similar criterion would lower the net present values further.

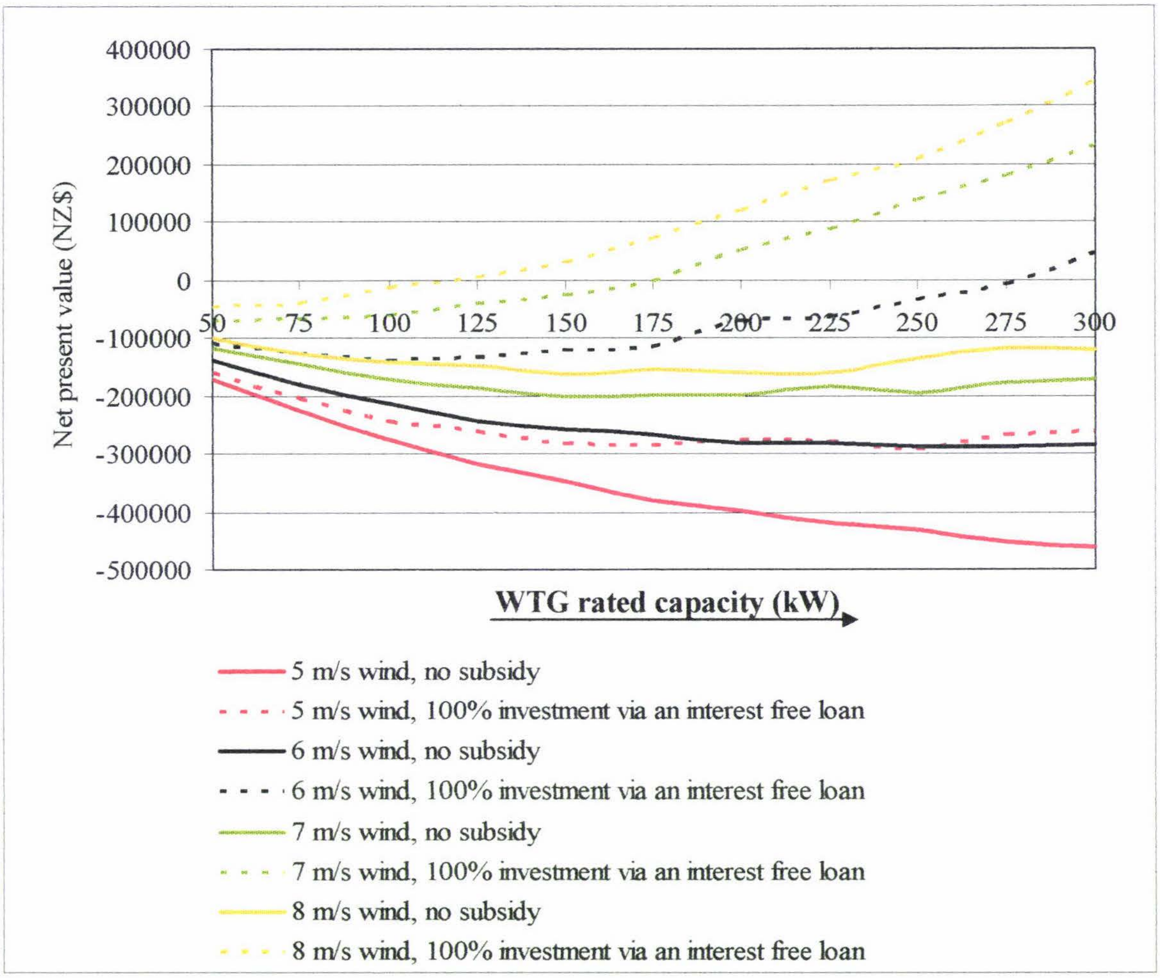

Fig. 8.18: The financial viability of medium grid connected, separately metered WTGs[16]

The financial viability of medium scale wind projects operating as self-contained generators but where additional revenue is derived for supplying of capacity during 50 out of the 92 days of the winter, in addition to the 'year round' energy sales is depicted in Fig. 8.19. Comparison of results in Fig. 8.19 with those in Fig. 8.18 clearly indicate that the viability of a wind project enhances under a capacity payment scheme.

It is important to note that the computer model outputs widely varying NPV values (and other financial indicators) when the frequency of critical peak periods is low. The reason why the results vary significantly from one simulating run to another (in spite of holding all input variables constant) is the stochastic nature of the wind resource.[16] The results depicted in Fig. 8.19 provides valuable insight to all three stakeholders; the investor, the state and the lines company.

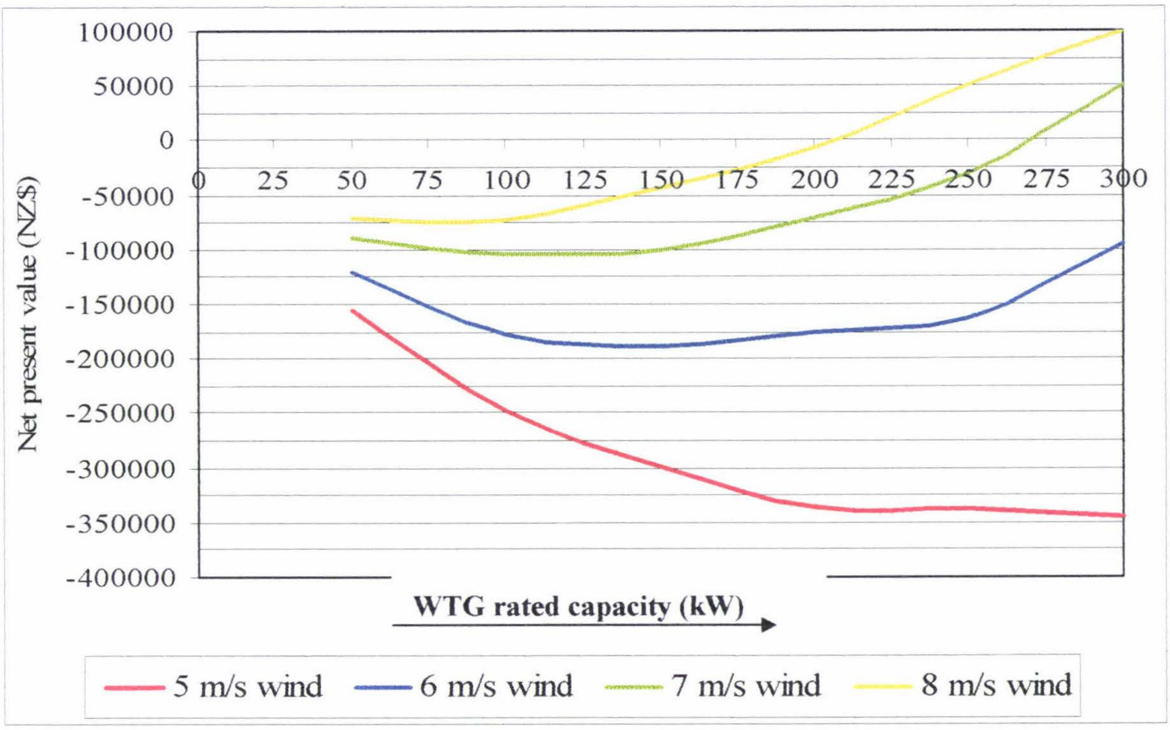

Fig. 8.19: The financial viability of medium grid connected, separately metered WTGs installed without any subsidy but operating under a lines company incentive scheme for providing firm capacity during winter, characterised by peak periods on 50 days, with each peak period lasting for 1 hour.

From the investors point of view the results show that the viability of medium scale grid connected WTG systems can become economical even under minimal subsidies from the state, provided the wind resource is good and that network capacity constraints occur frequently for which a lines company pays for the capacity provided during such constrained periods. On the same token, under these circumstances the state can benefit by providing a lower level of subsidy (as subsidies carry an opportunity cost) without jeopardising the uptake of wind energy. A lines company can benefit by knowing that

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[16] *Because the computer model picks the "critical peak period days" through a random process and each simulation run picks different days as "critical peak period days" (because each day in the season having an equal chance of being such a day), the capacity contribution (i.e. average kVA supplied during the peak period) does change significantly from one simulation run to another when the "critical peak period days" are few and far between. To illustrate this further, if one takes the antithesis and assume that everyday in the winter is a "critical peak period day" and that peaks necessitating capacity support occur at the same time and last the same duration, the peak period contribution will not change from one simulation run to another, meaning the same cash inflow for firm capacity support all the time.*

wind resource provides a notable quantity of capacity support overall, if capacity requirements occur frequently and if the wind turbine generators are installed in good wind regimes. Ironically, as a natural monopolist, a lines company could charge a monopoly rent by way of reducing the rates it pays to wind project investors, if the state subsidise renewable energy projects heavily.

8.3.1.2 Diesel generators

The financial feasibility of a small to medium scale diesel generating unit directly paralleled[17] to the grid without any power conditioning equipment (i.e. rectifiers and inverters) and operating as a peak lopping unit in response to the lines company ripple signals during critical peak periods is positive (Fig. 8.20). The simulations were run assuming investment in brand new equipment and obviously without any government subsidy as there is no renewable energy component involved in the project.

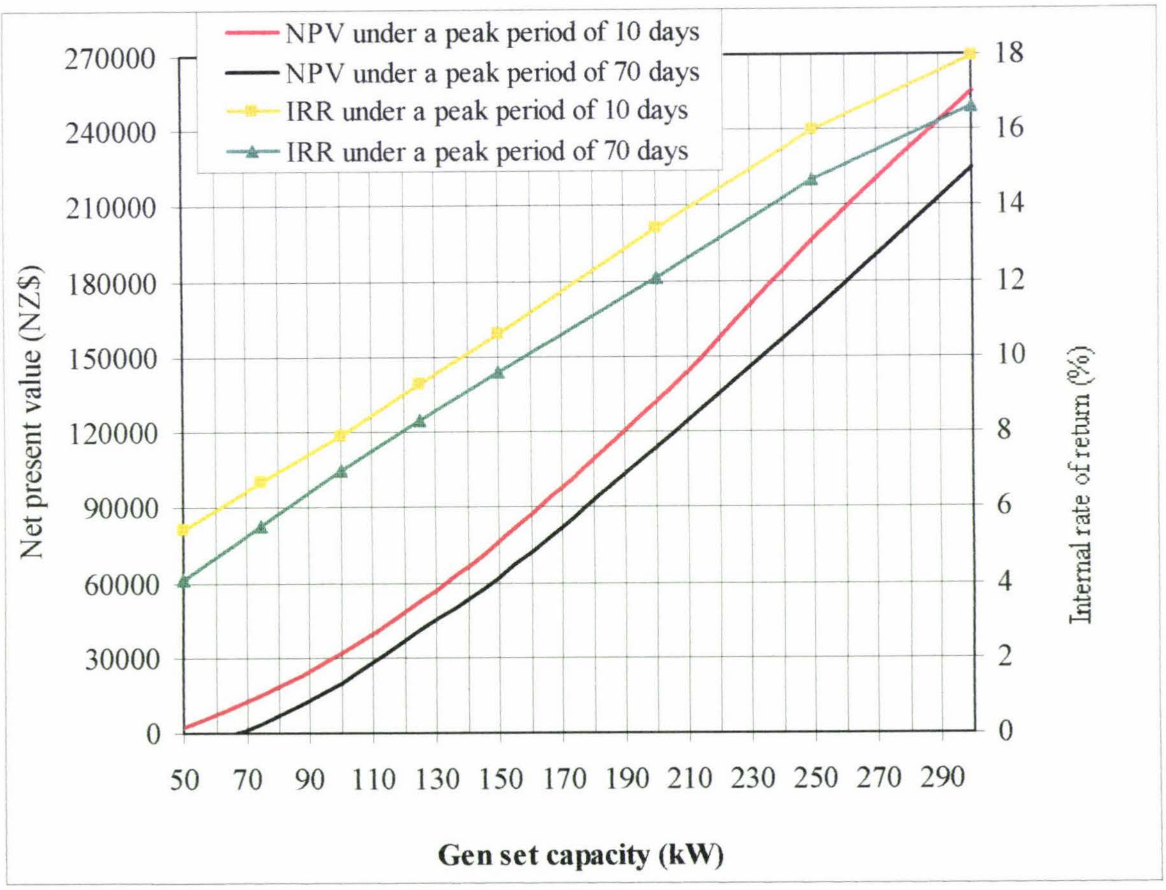

Fig. 8.20: The financial viability of medium grid connected, separately metered standby diesel generator operating under a lines company incentive scheme for providing firm capacity during winter

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[17] *The term 'parallel' is synonymous with the term synchronising as applied to alternators that are directly connected to the grid. The smaller standby generators (say less than 100kVA) are generally not meant to run in synchronism with the grid supply (AC waveform) and hence diesel engine-induction generator combination may be used instead.*

The rising IRRs in Fig. 8.20 suggest that it would pay to invest in larger diesel generating units because of higher financial returns to cover any form of risk involved in such a project. For example, there is always the risk of the lines company declining to pay the agreed sums at a later point in time (say in 5 years) due to its own investments in capacity reinforcement that makes capacity support by DG redundant. Such risks are covered by higher returns (i.e. rising IRRs) on larger diesel generating units primarily due to economies of scale resulting from the initial investment (Fig. 8.21).

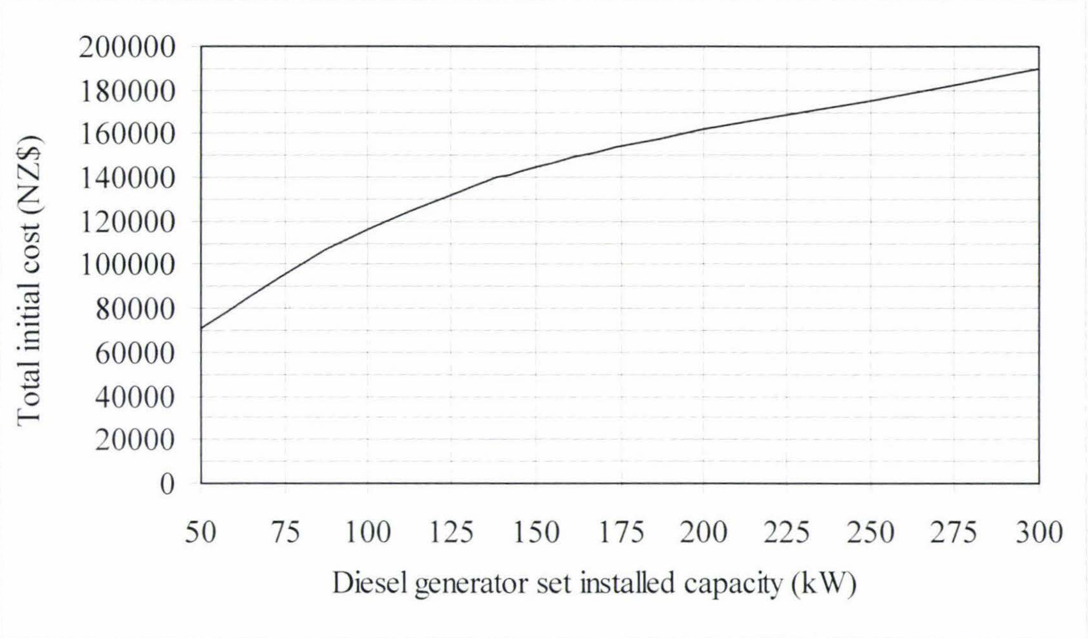

Fig. 8.21: The initial cost structure of a project, involving small/medium grid connected diesel standby generating unit, as suggested by the computer model

Fig. 8.20 also suggests that operating the diesel generator frequently reduce the financial returns from the project, meaning marginal revenue earned from energy sales is less than marginal cost inured in operating the unit. Note that as far as revenue from capacity supply is concerned, as long as the engine operates on full load, it does not make any difference how frequently the unit is operated because the average capacity supplied during the critical peak period (irrespective of its duration and frequency) remains the same.

Fig. 8.21 when interpreted in conjunction with Fig. 8.20 suggest that it pays for anyone who owns a medium scale standby diesel generator (thus the capital paid for already) to upgrade it for grid connection by investing in additional paralleling gear to operate as a grid connected unit when necessary. From a lines company perspective it is worthwhile to harness such resources by supplying the metering equipment and ripple receivers (through the incumbent retailers), which can ultimately be recovered from the DG customers by designing the right tariffs to provide firm capacity supply.

8.3.1.3 Wind/diesel hybrids

As seen in section 8.3.1.1, a medium scale wind project shows economic feasibility only upwards of 200kW (for sites with wind speed equal or above 8 m/s). It does not pay an investor to incorporate a WTG alongside a diesel generating set to take advantage of any lines company price signal. However providing some form of subsidy by the state to the wind energy component of a wind-diesel project will bring about a salutary effect (Fig. 8.22). The state could provide just enough subsidy so that a rational investor (within the framework of mainstream economic thought) would consider adding a WTG to the diesel unit. For example, providing a subsidy to install a 100 kW WTG in a 8 m/s wind regime, in the from of an interest free loan (to meet all costs in connection with the WTG), will raise the NPV of a 100kW diesel only project from NZ$ 23,042.00 to NZ$ 117,062.00, which is substantial (Fig. 8.22). The state can reduce the level of subsidy such that the NPV of the wind/diesel hybrid would be marginally over NZ$ 23,042.00.

Comparing the results in Fig. 8.22 with those in Fig. Q.8 of Appendix Q, section Q6, it is evident that from the state's perspective, the subsidy required for medium scale WTG projects is substantially less per kilowatt than subsidy required for smaller wind diesel hybrids. For example adding a WTG of equal capacity to an otherwise feasible low cost small diesel generator project will cause the project to become not feasible (Fig. Q.8) even if the capital could be raised through a zero interest load afforded by the state for the renewable component of the wind diesel hybrid and the wind resource is good (>8 m/s).

From a lines company perspective, any medium scale DG project metered separately for injection should not directly affect its revenue because the energy drawn by customer load does not count in cash inflows. In particular, with systems that always provide firm capacity, such as medium scale diesel and wind/diesel hybrids, the line losses become substantially reduced (hence the feeder loss factor reduces). The lines company can benefit from this if it is possible for the company to remain silent (i.e. not to revise its loss factors!). However since retailers always reconcile energy purchases with energy sales, in practice if lines losses are substantially reduced but not reflected in the loss factors stipulated by lines companies, this will be highlighted.[18] There is some form of in-built internal control for lines companies to prevent exploiting line loss reduction, for gaining additional revenue.

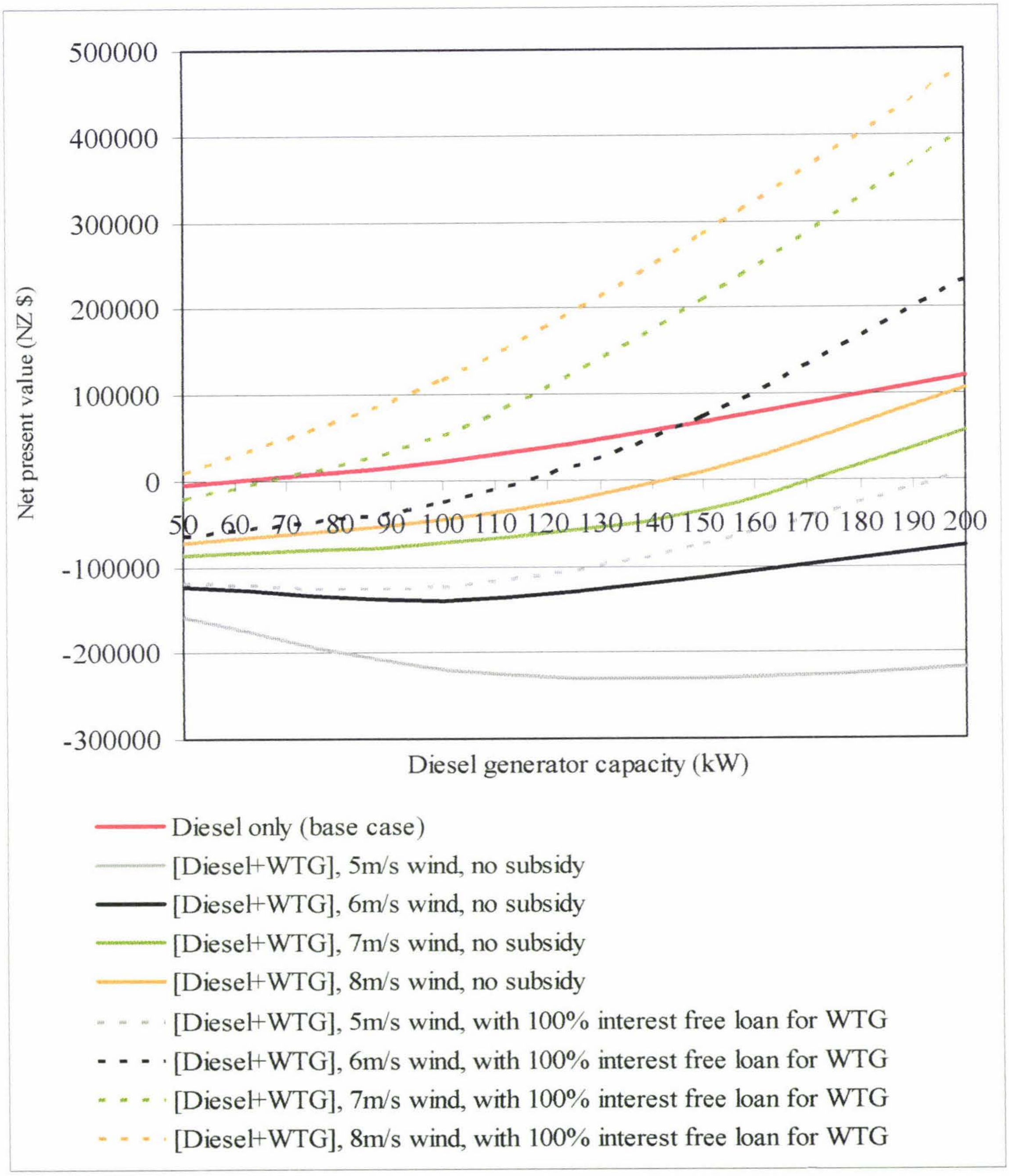

Fig. 8.22: The financial viability of medium grid connected wind-diesel hybrid system (of equal rated capacity) operating under a lines company incentive scheme for providing firm capacity during winter, characterised by peak periods on 50 days, with each peak period lasting for 1 hour

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[18] *Note that in appendix P, it was assumed that the sole purpose of dispatchable generation from a lines company perspective is capacity support of their own network. This is because it was assumed that a lines company does not receive any direct benefit (in the loner run) from Transpower by reducing the peak loads at the GXP, since Transpower can (and probably will have to) increase its connection charges to recover returns on its HVAC assets (section 2.5.3.2) in the event of demand side responses such as diesel generation, during critical peak periods.*

The wind-diesel hybrids as opposed to wind only systems may also be superior in terms of improving the power quality of the network. In particular, if it is possible to use a salient pole type synchronous generator driven by a diesel engine that could be decoupled from the engine when required (just to run as a reactive power compensator for the rest of the time), such a system could provide a substantial quantity of both leading and lagging reactive power all year long and possibly compensate the voltage flicker effects caused by the wind turbine generator to some extent (though a fast acting voltage regulator for the synchronous machine). However, the study of the dynamic response of grid connected wind/diesel systems (which is an important aspect in a weak network) was considered to be beyond the scope of this research. An interested researcher may however find the line parameters as depicted in Appendix E useful for modelling the systems.

8.3.1.4 Pumped hydro units and wind/pumped hydro hybrids

According to the computer model, operating a low cost 14.8 kW pumped hydro scheme to provide firm capacity is highly uneconomic.[19] The initial cost of NZ$ 69,631, as suggested by the computer model, is too high to payback from the project earnings of NZ$ 1,800 per annum that results primarily from providing firm capacity. The computer model outputs a net present value of <u>minus</u> NZ$ 61,555.45, under a scenario of only ten critical peak period days in the year (occurring in winter) with each critical peak period lasting one hour. It is interesting to note that unlike diesel, the NPV increases with the utilisation of the system. For example, according to the computer model, if the pumped hydro was to be used every day for peak lopping for one hour, the NPV would increase to <u>minus</u> NZ$ 58,969.92. This is because of low operating cost of the plant and the resulting additional revenue from buying energy at low cost (NZ$ 169 per annum) and selling it to the retails in evening peaks (earning NZ$ 270 per annum) when the electricity spot prices are generally high (i.e. tariff trading).[20]

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[19] *Note that 14.8 kW was the capacity that seemed most technically feasible for the Totara Valley terrain (section 6.3.1).*

[20] *Note that the owner of the pumped hydro system would not receive any additional revenue for supplying firm capacity by operating the unit more frequently. As shown in section 6.3.3, the lines company ScanPower will only be able and willing to pay NZ$ 120.00 per kW per annum in lieu of reinforcing their network by investing in capital goods (e.g. conductors, circuit breakers etc.). It is also interesting to note that revenue from firm capacity is the dominant revenue source and not the revenue from tariff trading with the retailer.*

The simulation results also show that subsidies cause NPV to rise only by about NZ$ 7,000 which is nowhere near sufficient to cause NPV to rise above zero and cause small pumped hydro projects to be viable.

Since pumped hydro projects are not financially feasible, it is clear that there is no incentive for an investor to choose such a unit into any distributed resource mix. Hence, it can be inferred that small scale to medium scale wind-pumped hydro systems are not financially feasible.

8.3.1.5 Battery banks and wind battery hybrids

According to the computer model, operating a battery bank to release energy at a rate of 18 kW to provide firm capacity is highly uneconomic.[21] The initial cost of NZ$ 44,321 for the system (including the battery charger, inverters and other power electronic devices), as suggested by the computer model, is too high to recover from the project earnings of NZ$ 2,050 per annum that results primarily from providing firm capacity. The model outputs a net present value (NPV) of minus NZ$ 36,222 under a scenario of only ten critical peak period days in the year (occurring in winter) with each critical peak period lasting 1 hour.

It is interesting to note that similar to the pumped hydro, NPV does increase slightly with greater utilisation of the system. For example, according to the computer model, if the battery bank were to be used every day for peak lopping for one hour, the NPV would increase to minus NZ$ 35,969. Although the computer model outputs a very low annual maintenance cost, its operating costs in terms of electricity costs for battery charging (NZ$ 360) exceeds the revenue earned form selling electricity to the retailer during peak hours (NZ$ 300).

Moreover, since lead acid technology is a modular technology, there will be no efficiencies of scale gained in opting for larger systems, unlike pumped hydro. Therefore, batteries become a poor candidate for peak lopping irrespective of the scale of application.

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[21] *Note that 18 kW was the discharge rate set for the selected battery bank based on C_{25} value of 6V, 210 Ah batteries. The bank required 22 batteries altogether.*

8.3.1.6 The effect of load control on separately metered community owned DG

The computer model allows customer initiated load shedding to be accommodated, for the purpose of incorporating cost savings on line charges during critical peak periods (section 6.2.2.1). However in order to derive economic benefits from load shedding, the community load needs to be recorded separately during critical peak periods. This requires investment in additional instrumentation and metering equipment, which is justifiable only if shedable loads of sufficient magnitude exist, which does not seem to be the case for Kumeroa and Totara Valley communities unfortunately (section 8.3.1).

If shedable loads of sufficient magnitude do exist, peak shaving through load shedding is more economical than peak lopping through DG. This is because load shedding does not involve expensive capital equipment such as diesel generators and approximately the same cash inflow will result for each kW of capacity reduced (through load shedding) or capacity supplied (through DG) to the network, giving the same net benefit to the lines company.

Metering of community load can be done at individual ICP level or through a 11 kV, 3 phase bulk supply meter installed at the feeder at the beginning of the community boundary. The latter scheme is easy to administer because there would be a single reading that can even be digitally transmitted to the billing centre. This is feasible only if a community is on the fringe of the network and all members of the community agree to a bulk billing system. The charges billed could be apportioned among the individual members of the community organization that operates the DG system.

8.3.2 Gross import/gross export metered community distributed generation systems

In terms of the configuration, gross import/gross export metered community DG system (Fig. 8.23) resembles a gross import/gross export metered, single farm based DG system (section 8.2).

One objective of analysing gross import/gross export metered community DG systems (its practicability notwithstanding) is to ascertain whether economies of scale could be realised through such schemes (section 5.5.2.2) and what impact such projects have on lines companies.

It is important however to note that the line tariffs applied to a community load (where the community is treated as a single bulk consumer), would be different from that of a single farm load. In the case of the latter, the applicable line tariff is 6 c/kWh in daytime and 4 c/kWh in night time (at GXP) as the total load of a single farm comes within the parameters stipulated by ScanPower for a standard commercial customer (i.e. a commercial customer whose annual energy demand is less than 100,000 kWh).

Since in the case of Totara Valley Zone B and Zone C community loads, the annual energy consumption is higher by ten fold and twenty fold respectively to that of a single farm (Appendix N), the applicable line tariff becomes 3.84 c/kWh day tariff and a 1.34 c/kWh night tariff (commercial option C4 stipulated by ScanPower, as shown in Appendix F). In addition to the above variable charges, the maximum demand charge of $ 4.00 per kVA per month (for winter months only) also comes into reckoning.

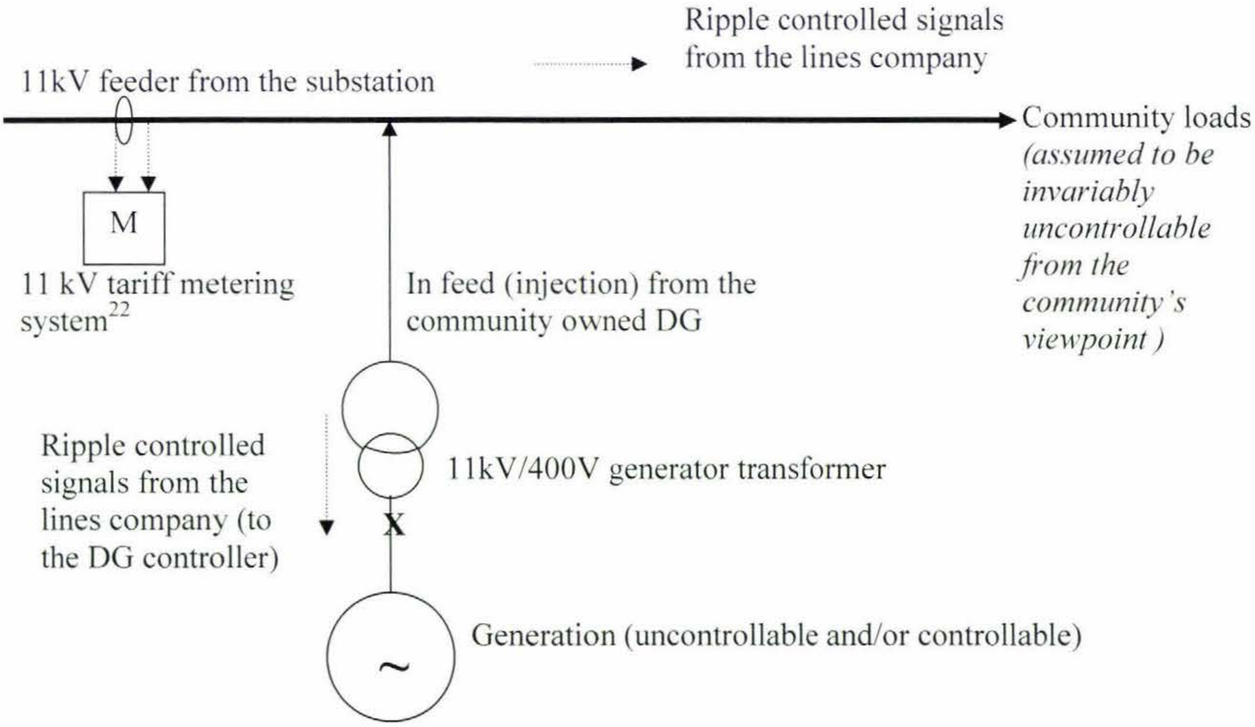

Fig. 8.23: The configuration of a community owned gross import/gross export metered DG system

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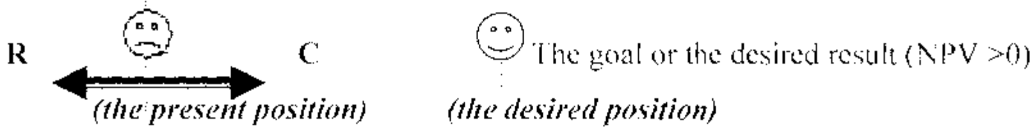
[22] *The 11 kV tariff meter is shown as it would be installed using voltage and current transducers on the line. In cases where a demand side response (i.e. dispatch of diesel generation) is made during critical peak periods, there will be an additional meter to record peak period capacity. This is the one and only one tariff meter based on which the whole community is billed!*

Due to a typing error, the NPV of a 55 kW wind turbine at 6 m/s wind speed under interest free loan was typed as −136,052.00, whereas it should be −36,052.00, causing the black dashed curve in Fig. 8.24 to appear abnormal in certain kW ranges. The error has since been corrected.

The following force field analogy will serve as a useful tool in interpreting the NPV results of Fig. 24 as well as many other NPV results in this publication.

In any project, there will be compelling/driving forces (denoted as "C" in the figure below) and restraining forces (denoted as "R") that influence the desired result. With respect to a DG project, the desired result can be a positive NPV value.



The following major Rs and Cs are identified for scenarios depicted in Fig. 8.24.

R	C
1. A high initial cost	1. A low discount rate (e.g. interest free loan)
2. Low retail tariffs	2. A good wind resource
3. Gross import/gross export metering philosophy (i.e. excess generation is bought at wholesale rate)	3. Economies of scale from increased kW capacity

(Note: Item 1 of R and item 3 of C are interrelated)

In keeping with current production trends, the model assumes that small wind turbine units (<50kW) are interconnected to the grid through an inverter and hence have a high initial cost. This high initial cost (restraining force) is compensated to some extent by a good wind resource and a low discount rate (compelling force). When the wind turbine units become 50kW and above, the initial cost drops comparatively (hence a reduction in the restraining force) causing NPV to rise. This is because the units are interconnected to the grid without an inverter. The 6 m/s wind speed with an interest free loan is a situation where beyond 75kW, Rs and Cs effectively nullify, causing NPV to be static near zero.

8.3.2.1 Results related to Totara Valley Zone B

8.3.2.1.1 Wind energy projects

The financial viability of WTG units based on the rated capacity (with or without a state subsidy) show clear economies of scale over smaller units used at the individual farm level (Fig. 8.24 compared with Fig.8.2). From the state's point of view, provided the gross import/ gross export metering is acceptable to the lines companies and that they are not charging heavily for using the lines for injection,[23] wind energy projects at a community level could be promoted with minimum subsidies. It is also important to note that Totara Valley Zone B is still a very small community and that even better leverage could be realised when wind energy projects are implemented at a much larger community level (section 8.3.2.2). Note that economies of scale for wind energy projects have been realised in spite of a much lower energy based line charge rate being imposed by the lines company, which actually acts as a negative factor.

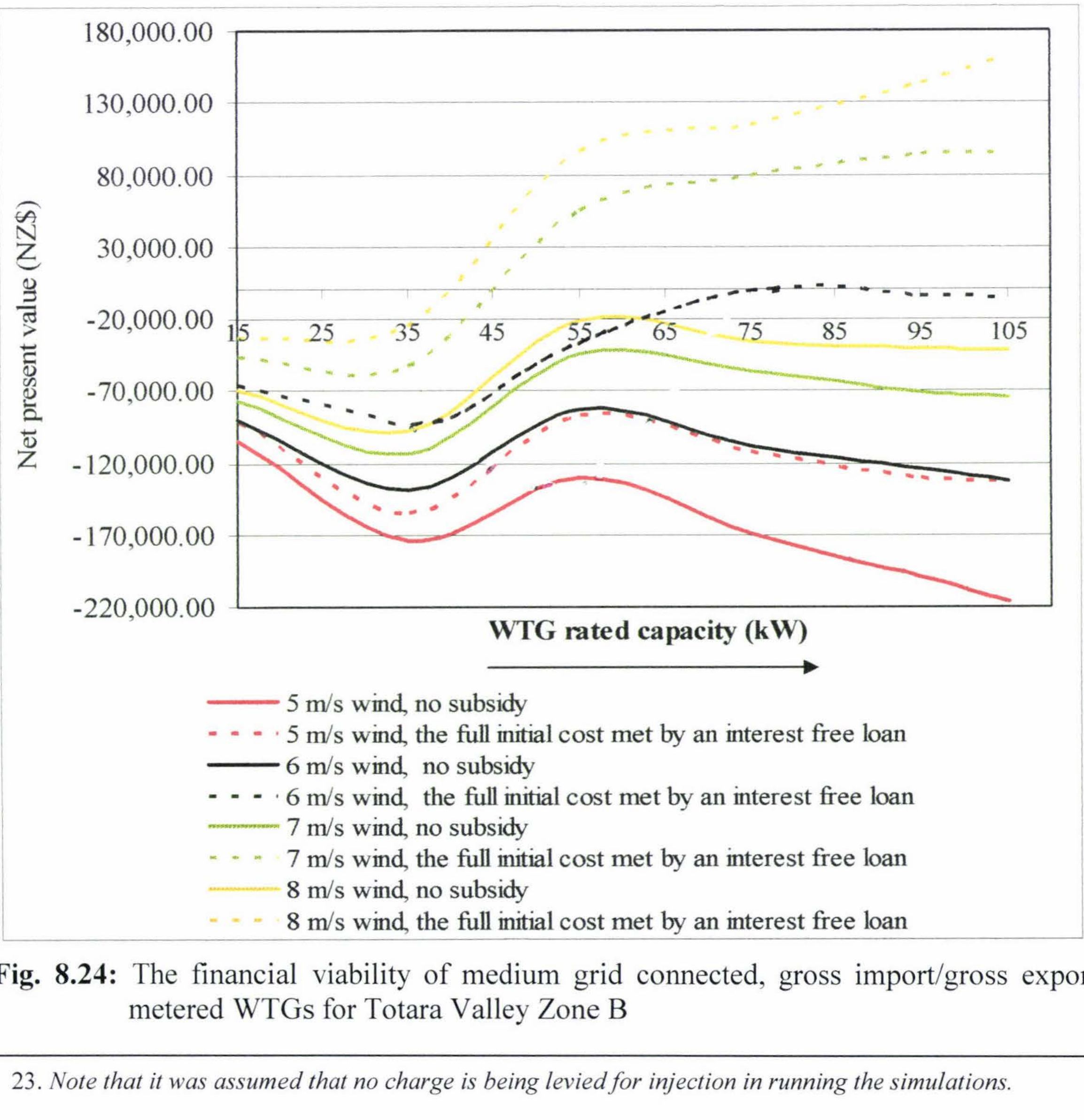


Fig. 8.24: The financial viability of medium grid connected, gross import/gross export metered WTGs for Totara Valley Zone B

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[23] *Note that it was assumed that no charge is being levied for injection in running the simulations.*

Comparing medium community scale gross import/gross export metered wind energy projects (Fig. 8.24) with separately metered wind projects of similar magnitude (Fig. 8.18) reveal that the former metering scheme is more favourable from an investors' point of view due to higher NPVs. In the case of the latter, the investor receives cash for the energy provided at electricity wholesale rates whereas in the case of the former the investor offsets energy charges and part of the line charges, being able to avoid grid electricity demand. This is also a reason why gross import/gross export metered community scale renewable energy projects were simulated and analysed.

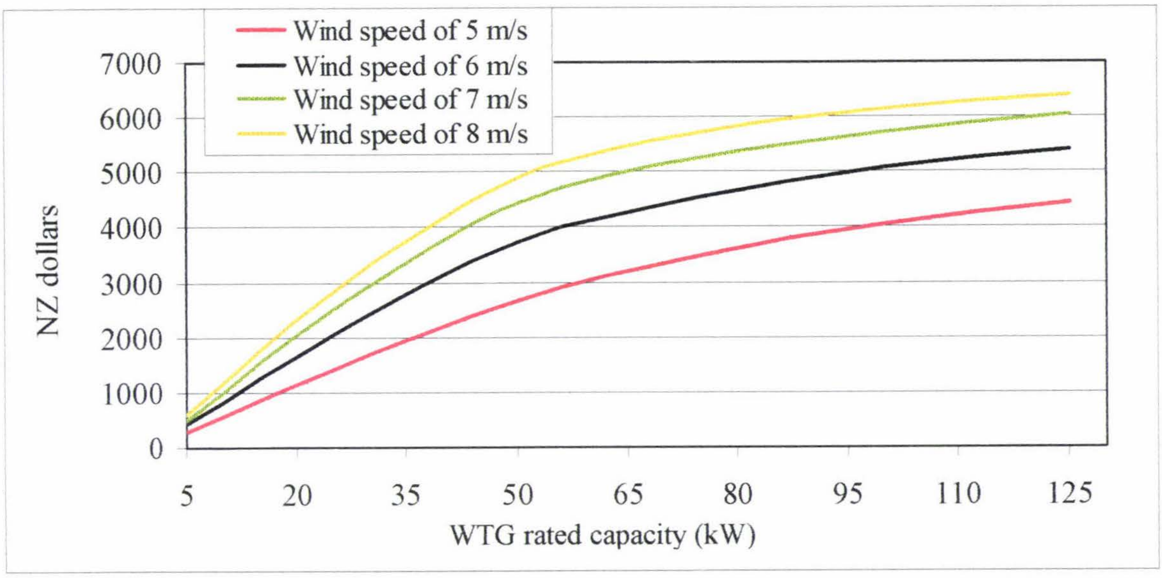

Fig. 8.25: The annual foregone revenue of the lines company under a gross import/gross export metering scheme for different WTG capacities under different wind regimes under existing line charges for Totara Valley Zone B

Comparing lines company revenue foregone for a medium scale community wind energy project (Fig. 8.25) with that of a single farm (Fig. 8.8), bearing in mind zone B's load is about ten times more than an individual farm load, it becomes evident that community scale gross import/gross export metered wind energy project has a relatively lesser impact on revenue reduction of a lines company, than individual farm based wind energy projects whose total installed capacity matches with that of a single community based project. This is because:

- a lower energy based line charge rate is imposed by the lines company in respect of a community load (section 8.3.2); and

- the inability of wind energy to reduce the maximum demand of the community load substantially. Simulation results show that in spite of good wind regimes, a wind turbine would have little influence in reducing the maximum demand drawn by the community load (not the demand at the GXP), as seen by the metering equipment (Fig. 8.23), because maximum farm load of a given winter month happens to occur at a point of time when the wind speeds happen to be generally low. It will only be by pure chance that a high wind speed would coincide with the maximum farm load in any of the three winter months.

Should subsidies become available, the computer model could be used by a lines company to ascertain how the economic viability of a community owned wind energy project would be affected by imposing a fee for using its network for inter-connection. From the lines company perspective imposing a fee would have a salutary effect. However, if DG is seen as an opportunity by a lines company to facilitate network reinforcement, it should set the fees at a level so that community owned gross import/gross export wind energy projects would not become uneconomic.

8.3.2.1.2 Diesel generators

Fig. 8.26 depicts the financial viability of a diesel-generating unit operating as a gross import/gross export metered peak lopping DG unit activated by the lines company ripple signals during critical peak periods. The simulations were run assuming investment in brand new equipment and obviously without any government subsidy, as there is no renewable energy component involved in the project.

Because the metering instrumentation is installed only at the grid leg in gross import/gross export metering (in the 11 kV feeder as shown in Fig. 8.23), the firm capacity provided by the diesel generator would normally be regarded as capacity net of customer load. Under these circumstances, simulations show that operating a diesel generator becomes uneconomic. However if the total capacity supplied through the generation is credited for example through a meter installed in the generator leg, peak lopping by diesel generation becomes economically viable and there is an incentive for the community to opt for a larger generating unit above 60 kW (Fig. 8.26).

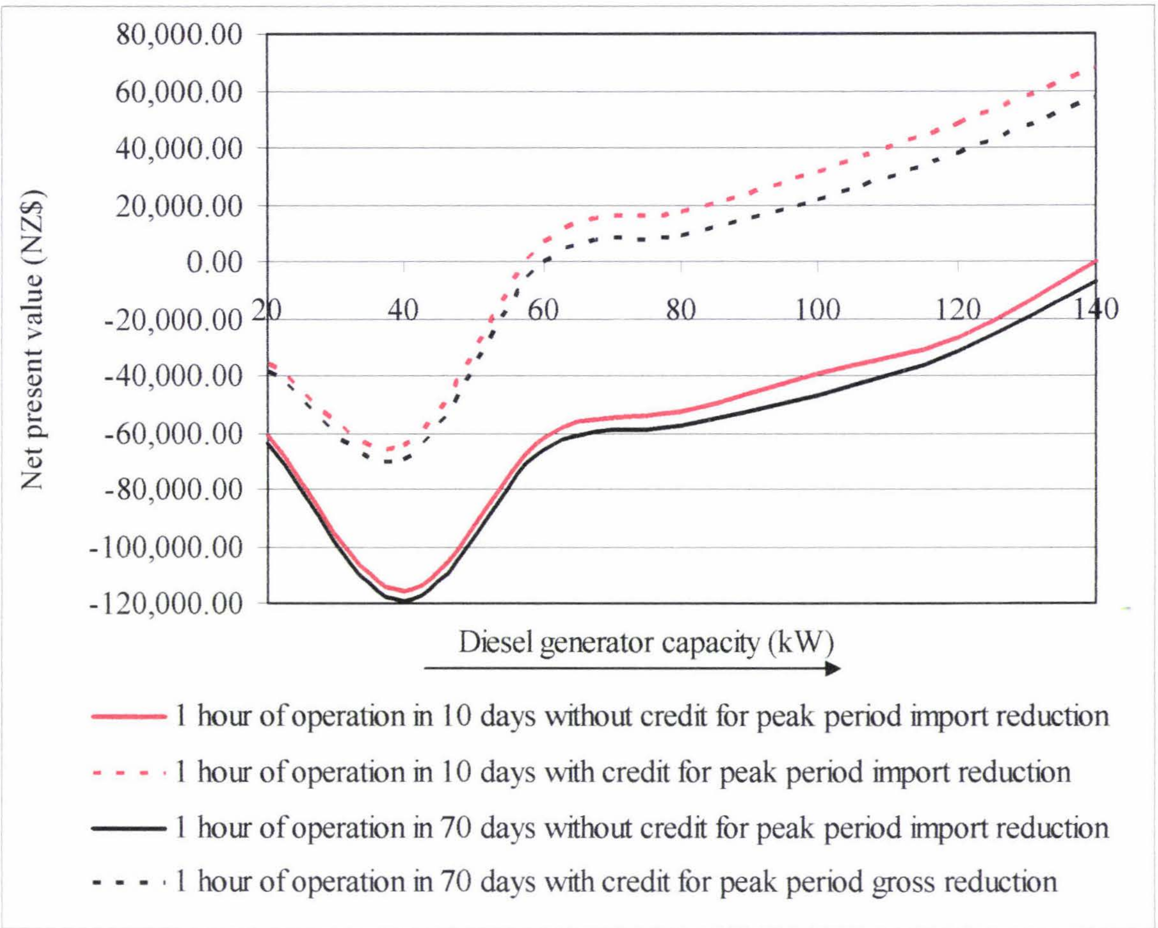

Fig. 8.26: The financial viability of a grid connected, gross import/gross export metered standby diesel generator operating in Totara Valley Zone B under a lines company incentive scheme for providing firm capacity during winter

There are two ways a lines company could credit whole of the capacity supplied through DG.

- Altering the metering system. An additional meter could be incorporated in the generation leg (Fig. 8.23), in which case the gross import/gross export metering system becomes a "separate generation-gross import/gross export hybrid metering system." The gross import/gross export meter could be used for the billing of the community for energy drawn and energy supplied as well as for the use of the lines company assets to draw energy. The separate generation meter (which needs to be ripple activated to record the contribution during critical peak periods only) could be used to credit the customer for the capacity supplied to the network during critical periods.

- Altering the lines company pricing strategy. The lines company can incorporate a pricing regime whereby capacity utilisation of its network during critical peak period is taken into account. Orion New Zealand Limited is one such company that adopts this strategy. When the customer is billed taking capacity (or energy) drawn through the network during critical peak periods, and because DG causes capacity (or energy) drawn from the network to be reduced (or diminished if the generation exceeds the load), the customer becomes automatically credited.

  Like most other lines companies, ScanPower's current method of pricing for lines services (apart from the fixed charges) incorporates a component based on energy drawn and a component based on capacity drawn (section 8.3.2). The component based on capacity drawn is based on the maximum demand drawn by the network user, which occurs at a particular point in time (half hour interval) of the month. When large commercial customers have different individual load profiles and the lines company faces a capacity problem, charging individual customers based on maximum demand has a lesser effect on reducing peaks than charging customers based on peak load at the origin (i.e. at the GXP). Under these circumstances it pays for a lines company to charge based on the maximum demand at the GXP (as done by Orion) as opposed to maximum demand of individual commercial customers.[24]

8.3.2.1.3 Wind/diesel hybrids

Community owned small and medium scale gross import/gross export metered wind energy projects need a state subsidy to make them economically viable (Fig. 8.24). However in areas where wind speeds are in excess of 7 m/s, a 60kW wind turbine generator (WTG) could be viable with only a very low subsidy. The implication of this result is that a rational investor will not incorporate a WTG into the generation mix, if there are no subsidies but would find operation of a diesel generator economical as a demand side response. However, with state subsidies an investor would find wind diesel hybrids more financially viable than diesel alone systems. Results pertaining to a 8 m/s wind site are shown in Fig. 8.27.

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[24] *One cannot however be critical of the existing pricing strategy adopted by ScanPower. To the author's knowledge, ScanPower does not have a capacity problem. Note that operation of a diesel generator was assumed based on a hypothetical situation whereby the "11 kV country feeder" was assumed to be reaching its rated capacity during critical times, which in reality doesn't exist at Kumeroa. However, as demonstrated in the Sri Lankan case study (Appendix-C) it is not always necessary for the local line to get overloaded for DG to provide capacity support.*

Results depicted in Fig. 8.27 show that the state does not have to subsidise a wind energy project heavily by way of providing an interest free loan. What it needs to do is provide a sufficient financial incentive (or the equivalent effect trough a carbon tax or similar) so that the wind diesel NPV curve would stay marginally above the diesel only NPV curve. It is clear that in areas with good wind regimes very little state subsidies are required to make wind diesel hybrids economically viable.

Another interesting result with regard to wind diesel hybrids is that at 8 m/s wind speeds, as the state subsidies are lowered, although the wind diesel hybrid NPV curve also lowers the curves do not cross one another within 105 kW installed capacity range (either wind or diesel) until subsidies are lowered heavily. The implication of this is that with little subsidy, not only could the state promote small-scale wind energy projects but also wind energy projects of larger magnitude.

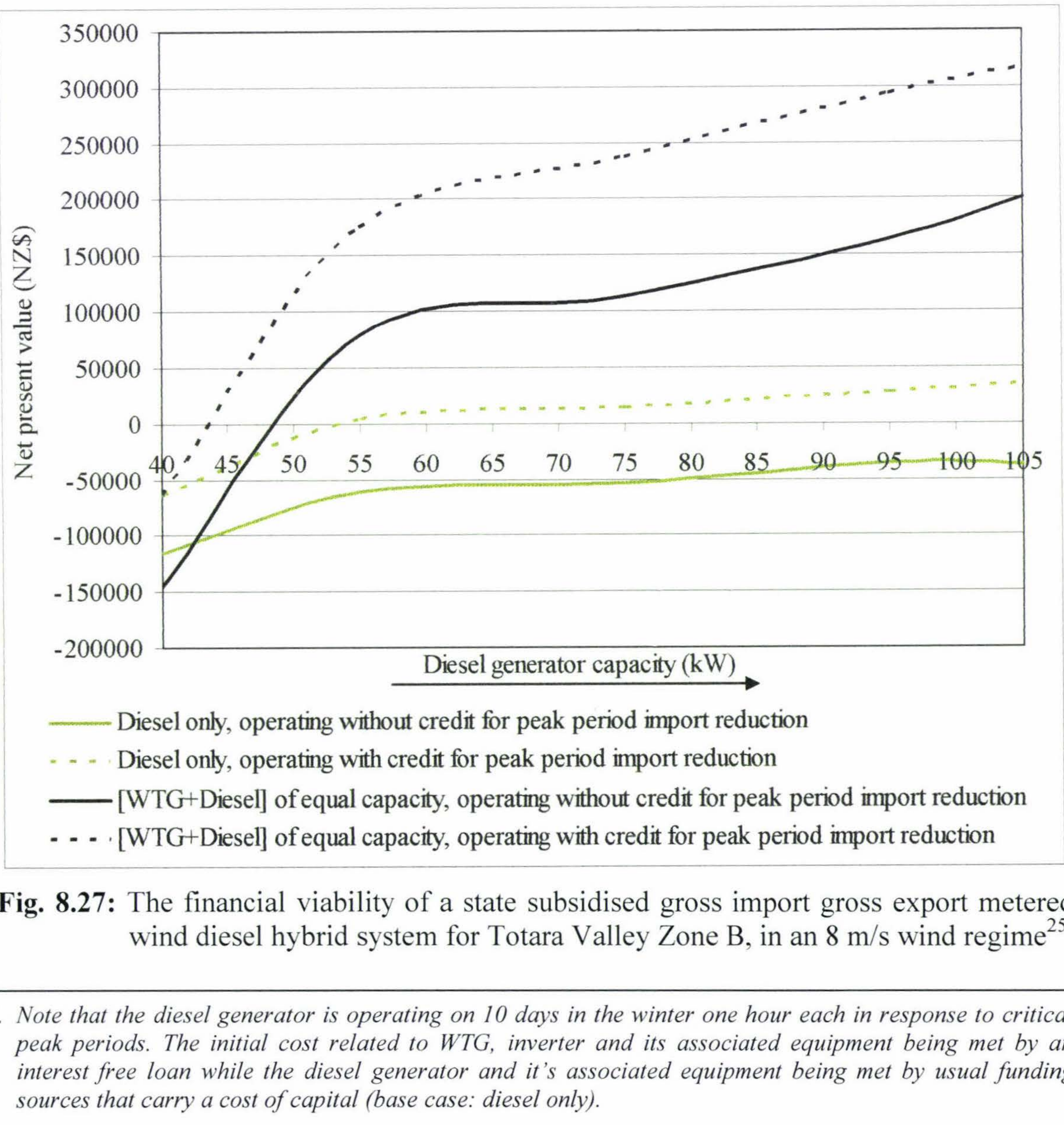

Fig. 8.27: The financial viability of a state subsidised gross import gross export metered wind diesel hybrid system for Totara Valley Zone B, in an 8 m/s wind regime[25]

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[25] *Note that the diesel generator is operating on 10 days in the winter one hour each in response to critical peak periods. The initial cost related to WTG, inverter and its associated equipment being met by an interest free loan while the diesel generator and it's associated equipment being met by usual funding sources that carry a cost of capital (base case: diesel only).*

8.3.2.1.4 Other hybrid systems involving WTG

Simulation runs on wind pumped hydro and wind battery systems show that incorporation of storage technologies makes wind energy projects extremely uneconomical. The reasons for this follow a similar explanation to separately metered hybrid systems referred to in sections 8.3.1.4 and 8.3.1.5.

8.3.2.2 Results related to Totara Valley Zone C

Simulation runs on wind only and wind diesel hybrids for the larger community (i.e. Zone C) show that such projects are more attractive and need even lower levels of subsidy (Figs. Q.10 through Q.13, Appendix Q, section Q6). The fact that the same tariff structure shall be used for both Zone B and Zone C and that Zone C load is nearly double the Zone B load (Appendix N), it follows that a lines company will forego double the revenue loss (Fig. Q.11). Therefore, large-scale community owned gross import/gross export metered systems are unlikely to be tolerated by lines companies.

8.4 ACCEPTABILITY OF THE RESEARCH HYPOTHESES

In section 5.5.1 it was hypothesised that dispatching a given quantity of generation at the right time is more beneficial to both lines companies and DG owners; the right time being those times of the day when the price of electricity delivered is expected to be high. Based on the analysis covered in sections 8.1 through 8.3, it could be stated that the hypothesis could be accepted only subject to a qualifying statement.

Throughout the research, it was identified that the price of electricity at a given half hour time interval can go up under two different and contrasting pricing regimes.

The first and the most common pricing regime would be (assuming that the customers are metered on time of the use basis) the customers being charged based on the spot price (or a pre-agreed wholesale price) for the energy consumed and a $/kWh line charge based on the time energy was consumed on the day; usually day time and night time. For large customers, the line charge can be based partly on energy drawn as explained above and partly on capacity drawn based on the maximum half hour demand made by the customer in a given month.

The second and less common pricing regime would be (assuming that the customers are metered on time of the use basis) the customers being charged based on the spot price (or a pre-agreed wholesale price) for the energy consumed and a capacity charge based on capacity drawn from the network during critical peak periods faced by the lines companies. DG systems are of economic value to both the DG investors and the lines companies on two counts; firstly because the load drawn by the users during critical periods can be shed by the user (based on a pre-programmed load shedding decision rule) and secondly because DG can inject capacity to the network during critical periods, for which the DG investor is monetarily rewarded.

The hypothesis was tested using dispatchable distributed resources (diesel generators, pumped hydro and batteries) and dispatchable-non dispatchable hybrid distributed resources (i.e. DG sourced by renewable energy) under both the pricing regimes (sections 8.2.4, 8.3.1.2, 8.3.1.3, 8.3.1.4, 8.3.1.5, 8.3.2.1.2 and 8.3.2.1.3). As seen in section 8.2.4, if the pricing regime were the first one, the research hypothesis cannot be accepted as displaceable generation is of no value to the lines company (as it does not face a capacity problem) or to the investor (as the required returns on investment cannot be realised). If the pricing regime were the second one the research hypothesis can be accepted as displaceable generation is of value to the lines company (as it receives capacity support) and to the investor (as the required returns on the investment could be realised). The necessary condition for the second pricing regime to exist is where there are critical peak periods faced by lines companies. As defined in section 6.2.1.3, the critical peak periods are those time of the day during which a lines company finds it difficult to supply the capacity required by the customers while maintaining the quality and reliability required by the customers. Hence, the research hypothesis can now be refined and accepted as follows:

"Dispatching a given quantity of generation at the right time is more beneficial to both lines companies and DG owners if the lines company faces a capacity problem at certain periods and charges customers based on capacity drawn during such periods and pays DG owners based on its avoided cost of capacity expansion, for the capacity provided during such periods."

Not all lines companies face critical peak periods however.

CHAPTER 9

The key recommendations for future progress

This chapter provides recommendations to the key stakeholders; the distributed generation (DG) investor, the state and the lines company whose conflicting objectives appear to be acting as barriers to find acceptable solutions to problems pertaining to grid connected DG and hence passing the benefits on to rural communities.

9.1 THE NATURE OF THE DECISION ENVIRONMENT

There are three key actors in the decision environment, whose actions affect one another in the overall implementation of a grid connected DG project (Fig. 9.1).

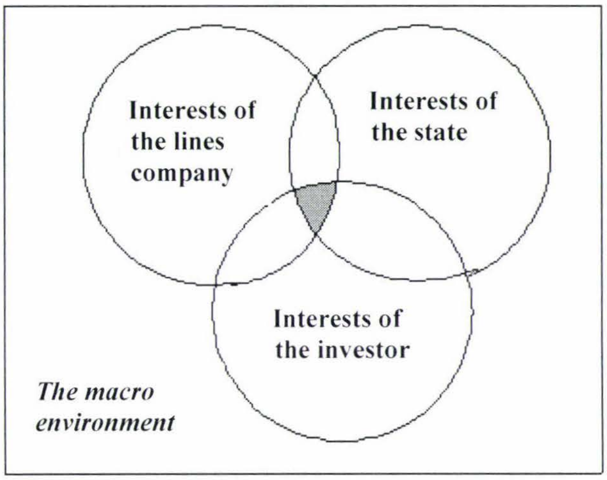

Fig. 9.1: The decision environment concerning grid connected distributed generation

1) The investor (in the case of Totara Valley, it was assumed to be either individual farmers or the whole community) is concerned with the profitability of the project and allocation of time among competing investment opportunities, bearing in mind the fact that the primary occupation of the investor is not power generation or electricity reticulation.

2) The lines company is concerned with satisfying the customer needs in an environmentally sustainable manner maintaining the required rate of return[1] on its investments, identifying the opportunities and threats posed by others including those who recourse to DG and other distributed energy systems and strategies to exploit or manage it, as the case may be.

3) The state on the other hand is concerned with the economic development, the environment (particularly the greenhouse gas emissions) and the general welfare of its citizens, where issues pertaining to a lines company and the DG entrepreneur are only a small subset of its total concerns.

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[1] *The required rate of return however will depend on the perception of the shareholders. Trust owned lines companies subordinate profits over concerns for the community they serve, while private owned lines companies aim to make more profits for the shareholders.*

The actions of the three actors are to a greater extent moderated by the actions of the macro environment; the other participants in the New Zealand electricity industry, global trends such as GHG concerns, technological advancements involving DG and so on. An attempt was made to reconcile the interests of the three actors (i.e. to enlarge the coloured area in Fig. 9.1) when making recommendations in this section.[2]

9.2 EDUCATION OF RURAL ELECTRICITY CUSTOMERS ON DISTRIBUTED ENERGY OPPORTUNITIES

Prior knowledge of the consequences of an economic decision is one of the most important perquisites to be an effective economic agent in a free enterprise system. In this regard large organizations can always gain economies of scale over an individual undertaking an economic activity because it can afford to employ specialists who can provide the right advice to the decision makers on the consequences of a particular project, before and during its operation. To a rural customer, such specialist advice comes at a relatively high cost.

Although a scientific study to ascertain the existing state of knowledge of the rural New Zealand public on "distributed energy" was not conducted due to time constraints, it was observed through the Totara Valley case study that community members were aware only of broad variables that affect different distributed energy projects. This applied to both DG as well as other distributed energy systems such as solar hot water heating. In particular, the residents were not fully aware of all the key factors that affect a renewable energy investment decision and how each factor can affect the project outcome. As seen in section 8, wide array of variables affect the economic viability of a DG project. For example, a rural sheep and beef farmer contemplating on investment of a small wind turbine to offset electricity charges would only be able to make an optimum investment decision (e.g. selecting the right capacity) only if he or she has a knowledge of the wind resource available, the metering arrangement in place, current electricity tariffs, cost structure of the initial investment, available subsidies and any conditions imposed by the retailer and the lines company.

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[2] *The author draws inferences heavily from the concept of "pay off matrices" which comes under the purview of "game theory" in decision science. According to the "game theory" when different parties have a common area of interest, they need to corporate with each other in order to maximise the payoffs of the individual parities. A simple real life example would be to corporate with the "right of way rule" in a busy urban traffic intersection. If the rule is not complied with by parties coming in different directions to an intersection, it would result in long queues, with neither party being benefited. In the case of the author's research area, the common area of interest for the three parties concerned is "distributed generation", especially technologies involving renewables, for different reasons.*

9.2.1 Importance of having to have all the information influencing an economic decision

In the real world, no human being is able to foresee the consequences of all the economic activities with infallible accuracy (section 8.1.1). Any project will have its own in-built financial risk. A person who is ignorant of facts that need to be evaluated before making an economic decision will unfortunately add a substantial premium (as financial risk) to his or her cost of capital in discounting cash flows.[3] In respect of small and medium grid connected renewable DG projects, as outlined in section 8, the cash inflows do not normally exhibit a high enough value to cover the initial investment, after allowing for "time value of money." Hence applying a high discount rate due to perceiving a grid connected renewable energy project as a high risk project (due to lack of knowledge of all the consequences) causes the net present value to go down further, leaving implementation of the project to be very unlikely.[4]

Since the state has a direct interest in renewable energy uptake, social welfare, and electricity supply issues pertaining to the rural regions, it has a major role to play in educating its citizens on the relevant aspects of distributed energy and their impact on energy investment decision making.

State subsidies (or similar interventions in the form of taxes on thermal generation) are of little use if rural communities are unable to determine the optimum distributed energy application contingent to their own situation. In providing subsidies, the state cannot discriminate its citizens based on narrow criteria such as providing low interest loans for rural residents who are willing to install wind turbines in windy areas although such a criterion can leverage greater uptake of wind energy (e.g. section 8.2.1). In an unregulated economy such as New Zealand, the state can only set broad criteria for provision of direct incentives on renewable technologies and the citizens are deemed knowledgeable enough to make decisions affecting their investment outcomes on distributed resources. As seen in section 8, there is no single best way of utilising a distributed resource as the decision outcome is contingent on a number of factors. For example, a New Zealand farmer who is

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[3] *In many ways, applying a substantial risk premium to the cost of capital could be thought of as analogous to a novice structural engineer applying a high safety factor in designing a building, purely because of his or her lack of complete knowledge on the relevant engineering design aspects. The upshot of applying the high safety factor is a very uneconomic design; more steel, more concrete and so on.*

[4] *Note that the computer simulations and the analysis of results (section 8) were made based on the assumption that the financial risk of the investor is zero.*

in a position to harness a steady water stream (with sufficient head) to generate electricity and connect it to the network (using a low cost technology) could be better off proceeding with it than installing a small grid connected wind turbine even if he or she believes that a very good wind resource exist.

The New Zealand government uses its agents such as the Energy Efficiency and Conservation Authority (EECA) to educate the general public. EECA in particular has posted a series of articles such as "energy wise practices" aimed at the general public and industrial organizations. One current focus of EECA seems to be to provide information on distributed energy technologies and energy use practices at individual technology level. Energy generation and reticulation is not the primary occupation of the general public (hence there is a lack of expertise) and the ability to raise the capital is limited. It is therefore important that educational programs be directed to compare different energy supply systems under a range of possible scenarios.

9.2.2 Demonstration of renewable energy schemes

In unfamiliar areas such as grid connected DG, it is important to actually establish model applications in different geographic locations in New Zealand so that they can be used as frames of references. While there are some industrial scale DG applications (section 2.7), there are no community scale grid connected DG applications reported in New Zealand. This will cause investment in grid connected DG to be perceived as risky.

9.2.3 Lines company initiatives

There are number of economically viable grid connected rural DG schemes that could be implemented both at individual farm level and community level (section 8). The economic viability however will be contingent on a number of decision variables applicable to any given situation. Analytical tools such as the computer model outlined in section 6 can be used by lines companies to determine the foregone revenue, which in turn could be used to rework tariffs acceptable to both the DG investor and the lines company.

Contemporary business organizations need to achieve objectives taking into account the well being of the society in which they operate (Kotler *et al*, 2001). In conducting this study it was observed that a lines company could provide several hardware components (e.g. cables required for inter-connection, transformers) at very competitive prices to communities by using their inventory stocks. This means that with bona fide intent on the well-being of rural customers, a lines company such as ScanPower could provide both material and labour (technical expertise) for community owned, grid-connected DG applications.

9.2.4 Social benefits

Distributed energy use at community level brings about many social benefits. Sustainability of the environment and use of local raw material, improvement of the quality of life of people, development of human capital are some. These carry a certain utility (satisfaction) to a community. It is important that social benefits are quantified objectively and demonstrated as part of the education and demonstration process. Social benefits can be included alongside the monetary benefits and then investment objective in a rural distributed energy project can be viewed as optimisation of net future utility of the community.

9.3 GOVERNMENT INCENTIVES FOR DG IMPLEMENTATION

New Zealand government has avoided direct subsidies for renewable energy projects up until this present time other than for recent opportunities for solar hot water installations (EECA, 2003). However due to current high cost of renewable energy systems, in order to realise widespread application of small to medium scale grid connected renewable DG, it would be necessary to provide financial incentives as an interim measure. State involvement in renewable energy development is important because in a community context it could be viewed, in part, as a good containing social value. Since financial incentives are currently necessary for distributed energy applications to be developed, in order to derive maximum benefits, the state has to consider two important priorities;

- the right level of financial incentive (9.3.1).
- the right time to provide the financial incentive (9.3.2).

9.3.1 The right level of financial incentive

From the analysis in section 8, at least six variables could be identified as having a positive influence on the extent to which a financial incentive is required for DG viability.

- the degree of renewable energy intensity (flux) available in the locality (e.g. annual average wind speed);
- extent to which DG is valued by the lines company (e.g. reliance on distribution network capacity support from DG during critical peaks);
- the metering arrangement (e.g. net metering Vs gross import/gross export metering);
- the prevailing cost of technology (e.g. conventional Vs low cost options);
- the customer load (e.g. single farm load Vs community load);
- the rated capacity of the generating source (e.g. small wind turbine generator Vs medium wind turbine generator).

The state has no direct control over any of these variables. However, it can exercise indirect control over most. For example the state, under the electricity commission, will be able to exercise some control if lines companies are exercising excessive monopoly powers and also if utilities undervalue the services provided by DG by unfair tariffs and dubious metering and billing arrangements.

Handling the issue of customer load and rated capacity of the generating source for the purpose of determining subsidies, is linked with the basic economic problem "who should be provided with what". These decisions are macro-economic decisions and should be consistent with the national sustainable energy policy being developed. The micro-economic analysis (section 8.3), suggested that it is more beneficial for the state to provide economic subsidies for centralised community scale renewable DG applications than for individual farmer applications due to;

- more renewable energy being leveraged for a given level of subsidy due to economies of scale exhibited by larger units, and
- greater benefits to society.

However not all distributed energy applications can be aggregated to form economical centralised community projects, hot water heating being such an example.

9.3.2 The right time to provide the financial incentive

It is imperative that potential entrepreneurs are educated on all the relevant aspects of distributed energy before subsidies are introduced. This way the state can ensure that the right choices are made by its citizens for the right reasons and hence gain maximum benefit from investment. As an example, consider a rural sheep and beef farmer contemplating connecting a small wind turbine generator to the grid. Based on today's technology costs and line tariffs (e.g. 6 c/kWh day charge and 4 c/kWh night charge for Totara Valley residents), a major portion of an interest free loan afforded by the state could be paid off during the life cycle of the project, if the farmer installs a 6 kW wind turbine generator in a 8 m/s wind regime (Fig. 8.2), provided the lines company and the retailer agrees to charge the customer on net metered basis.

It is recommended that a low state subsidy be initially provided for selected renewable energy technologies in order to create an interest among rural entrepreneurs to undertake small and medium scale grid connected DG. As rural entreprenuers become more knowledgeable on the economics and social benefits of distributed energy, the state subsidies can be increased in order to cause a growth phase. The state subsidy will also act as an incentive for those who undertake small and medium scale renewable energy projects which are deemed risky in financial terms. An entrepreneur can think of a subsidy as the reward for undertaking the risk. Subsequently, as line charges are increased in the future to cover returns on rural distribution assets and the cost of technologies decline, the state can gradually phase out subsidies without affecting the uptake of renewable energy technologies.

Based on the renewable energy technologies simulated in section 8, only wind and micro hydro could be made economically viable through state subsidies. However in the future there may be others that deserve subsidies such as bio-fuels to replace diesel in internal combustion engines, passive solar heating systems and so on.

9.4 LINES COMPANY MARKETING AND STRATEGIC PLANNING

In setting pricing options for the supply of lines services lines companies generally believe that electricity is very demand inelastic (that is to say if the line charges are increased, the demand drops only marginally). Stated alternatively, lines companies believe that small scale distributed resources pose little threat to a lines company. Indeed this view is globally accepted by electrical utilities and is the reason why net metering is tolerated by many utilities for domestic supplies. Lines companies believe that current costs of small scale (micro level) distributed resource technologies are cost prohibitive and that very few people would undertake investing in such technologies at present and hence net metering causes little threat to company revenues (Roche, 2001).

However, viewing small-scale DG as inconsequential is very myopic as lines companies need to understand that the environment within which they operate is very dynamic. Customers are learning more about distributed energy opportunities, the technologies are improving over time, the state could provide incentives to undertake renewable distributed energy applications and also invoke rules to prevent lines companies using excessive monopoly practices (e.g. unfair interconnection charges for DG). In the face of these growing environmental factors, increasing the lines charges to offset any foregone revenue on DG would in fact hurt lines companies in the long run as the demand could drop sharply as the charges are raised (section 9.3.2 and Fig. 8.2). For this reason, lines companies need to continuously monitor developments in the business environment and devise strategies to manage distributed energy applications in order to minimise threats and maximise opportunities.

A broad business focus is essential for any business operating in a dynamic environment. A business that defines its focus in very narrow product terms is likely to collapse in the end due to failure to identify the broader picture. Two classic examples from the past that could be cited are horse carriage and the slide rule manufacturers. These businesses were preoccupied with providing trendy products but failed to appreciate the wider picture and adapt to the changing environment; the development of the internal combustion engine and semiconductor technology. Those that defined their businesses as *"we are in the industry of providing transport needs to the people"* and *"we are in the business of providing computational equipment to the people"*, were able to embrace the new technologies

(Kotler, 2001). By the same token, it could be argued that New Zealand customers need distributed lines, transformers and electricity meters only as a means to an end (i.e. to meet their energy requirements). Changing concepts such as DG and hydrogen technology used in conjunction with fuel cells can hurt lines companies in the long run if they continue to have a very narrow product focus.

The only way a lines company can adapt to the changing environment is to find solutions to its potential problems through new technology taking the actions of the customers and the state into consideration. In this regard, recommendations are made in dealing with the revenue reduction (9.4.1) and use of DG as an alternative to capacity augmentation (9.4.2).

9.4.1 Dealing with reduced revenue

The issue of revenue reduction arises when a lines company bases its product prices mainly on per unit energy sales (i.e. $/kWh). It is important to note that any metering benefit that is passed on to the customer comes at a cost to the lines company and vice versa. For example allowing a consolidated farm load to be net metered greatly enhances the economic viability of a small wind energy project under favorable wind conditions and state subsidies, but the lines company foregoes an appreciable revenue loss consequently (Figs. 8.2 and 8.4).

Imposing charges to cover whole of the revenue loss would render small, grid-connected DG projects completely uneconomic. This would not be tolerated by pressure groups (including the state) as lines companies need to look for alternative strategies. Considering the fact that lines services for many rural communities are heavily subsidised, lines companies can gradually remove these subsidies in order to cause line charges to increase. For rural customers who are undertaking DG, an increase in the line charge (c/kWh component) acts as an incentive while for a rural customer who is not investing in DG, an increase in line charge acts as a disincentive. As explained in section 8.2.1 (and also illustrated in Fig. 8.4 and 8.5) a lines company can safely increase its line charges without seriously inviting DG, unless the state subsidises small-scale DG projects heavily.

In the short run, it is undesirable for the state to provide subsidies for distributed energy projects (section 9.3.2). Therefore, as a strategy to manage small-scale DG, the lines companies can gradually remove their cross-subsidies provided for rural communities. In the medium term when DG reaches a growth phase, lines companies can resort to different metering techniques such as time of use (TOU) gross import/gross export metering, which is less financially detrimental (Fig. 8.5) and easy to administer. Moreover, there has been significant progress on digital energy metering technology, meaning implementation of TOU metering would become less costly in the near future. Additionally, in the longer run, the lines company can commence charging small DG owners (or increase charges if it already charges a levy) for using its network. It is important to reiterate that any gain to a lines company comes at a cost to the customer. Hence when designing tariffs and/or altering metering techniques, a lines company should time its decisions in a manner such that that a potential investor would be able to absorb the costs by compensation from other gains such as reduced capital costs. The only way a lines company can achieve this is by cooperating with small-scale potential DG investors and existing DG system owners and constantly monitoring the technological growth and learning curve effects.

As regards managing medium and larger scale DG owners such as community scale centralised applications, a lines company can adopt a range of strategies. One is to collude with the retailer and stipulate separate generation metering as the metering of choice, so that lines company revenue collection is not directly affected (section 8.3.1.3). Another is to change the line tariffs to reflect maximum demand of the installation or critical peak periods faced by the lines company. Since a renewable distributed resource does not provide always significantly high capacity support during peak periods (due to the intermittent nature of the renewable energy resource), such a strategy would minimise losses to a lines company. Charging medium scale installations based on critical period loads and paying DG owners for capacity supplied would encourage investors to incorporate more dispatchable DG and load control, which in turn will benefit the lines companies (sections 8.3.1.2 and 8.3.1.6).

9.4.2 Distributed generation as an alternative to capacity augmentation

Payments to DG owners for capacity supplied during critical peak periods can be used to accommodate the interests of both the investor and the lines company (sections 8.3.1.2, 8.3.1.3, 8.3.2.1.2 and 8.3.2.1.3). A lines company depending on how a medium scale customer is metered and the level of state subsidies, can lower what it pays DG owners (i.e. to charge a monopoly rent) without seriously affecting the possibility of losing network capacity support. Capacity may either come through 100% dispatchable generation (in which case the capacity supplied becomes a firm capacity commitment), combined dispatchable plus non-dispatchable generation such as wind/diesel hybrid generation or even renewable DG (in which case it is not a firm capacity commitment).

9.5 TECHNOLOGICAL DG RESEARCH AND DEVELOPMENT

Engineering works or schemes are not designed or constructed as engineering challenges; in the case of an individual investor, an engineering project will be built for motives of profit.[5] In the case of a community it will be built for profit, social benefit and community leadership (Mitchell, 1996).

In order to achieve the above objectives the investors have to have recourse to DG technologies that are either at the maturity stage (e.g. reciprocating engines, micro hydro) or evolutionary stage (e.g. wind, solar hot water) of their product life cycle. Mature technologies are proven (hence there is less risk of them not meeting the expected performance) and are low in cost.

Because of the engineering challenges and technological marvels, researchers engaged in technological development of renewable energy systems are often preoccupied with technologies that are at the introductory phase such as fuel cells and hydrogen, which are not yet economical to be implemented commercially. While continuous research and development of these technologies is paramount for viable future implementation, it is equally important that the existing mature technologies be further developed and new markets found.

Observation and analysis of simulation results (section 8) demonstrate how mature technologies such as micro hydro and induction generators driven by internal combustion engines could be used to gain economic benefits to individuals as well as to communities. These technologies also provide capacity[6] to the distribution lines when required, which

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[5] *The term profit is used here to mean the shareholders' expected rate of return, which varies from case to case.*

[6] *The term 'capacity' is used here to distinguish from 'firm capacity' because of micro hydro generation. A micro hydro plant cannot necessarily guarantee that a particular capacity will be delivered at a particular time because of the fluctuations in water flows. Firm capacity can be provided by a micro hydro if a reservoir is incorporated. However when a run of the river type micro hydro plant is installed in a stream having a steady water flow, such as in the case of Totara Valley, it can deliver considerable amount of capacity to the network.*

benefits the lines company as well. There is plenty of scope for research in the area of product development so that these technologies can find more and more grid connected distributed resource applications.

9.5.1 Low cost micro hydro

As seen in section 8.2.3, low cost micro hydro projects are feasible in rural areas where steady hydro flows and water heads of reasonable magnitude exist. Using a centrifugal pump (the most common water pump in the world and hence cheap) operating in the reverse direction and used to drive an induction motor (the most common electric motor in the world and hence cheap) as an electrical energy generator[7] results in a simplified electro-mechanical configuration. This enables low cost micro hydro to become much cheaper than other technologies (sections 3.4 and 8.2.3).

However designing a centrifugal pump that could be reverse operated as a turbine is an engineering challenge (section 3.4) and warrants research and product development effort to use this technology in a wide variety of micro hydro applications. Because of the economic attractiveness of the low cost micro hydro, it is recommended that this technology be further studied to ascertain whether site conditions such as variable water flows associated with run of the river type applications act as barriers to the implementation of this technology. To this end, it is recommended that communication be established with international agencies who have successfully implemented this technology.

A conventional water turbine (e.g. Pelton, cross flow) may also become economical if it drives an induction generator, because part of the low cost micro hydro benefits (simple interconnection that avoids the use of power conditioning equipment) is passed on to such a turbine-generator combination.

From the state's perspective, low cost micro hydro technology is important because subsidies are not required for such technologies (section 8.2.3).

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7. *In order to cover this multitasking function, the generic induction motor is referred to as an "induction machine," in electrical engineering. The term encompasses the use of the electrical machine in a range of applications; as a motor (which is the most common), a generator and an electric brake (e.g. in an elevator).*

9.5.2 Application of the induction generator

Since an induction generator is an induction motor turned by a prime mover in the same direction and induction motors are widely used in many domestic and commercial applications, it becomes a potentially cheap energy converter. In addition to direct use as a generator in grid connected micro hydro and reciprocating engine technologies, in a very broad sense, any three phase induction motor installed to drive a load can effectively be operated as an induction generator. This assumes the load could be decoupled and the motor could be driven by a prime mover. It is not necessary to have any interfacing devices because the existing circuit breakers, electrical protective relays and the motor starters can be used for this purpose.

Moreover, in applications such as peak lopping for capacity support, the generator is expected to run at its rated capacity, which for an induction generator means operating at a fixed speed that simplifies speed governing control system. Shutting down a motor during a critical peak period also avoids a substantial line charge, if the customer's critical period load is separately metered. If the motor could be operated as a generator during this period, the customer would receive a cash income from the lines company for supplying capacity.

For the above reason, it is useful to conduct research on low cost electro mechanical devices such as electrically activated clutches that could be used as coupling/decoupling devices to decouple a motor load and to couple an internal combustion engine such as a diesel engine, which can even be a farm tractor engine. This technology will greatly benefit rural communities if large centralised motor loads (that could easily be decoupled) could be found, within the communities.

9.5.3 Wind resource assessment

As a distributed energy source, "wind" provides a unique benefit to an investor over "solar" and "hydro", in DG applications, because not only it is a scaleable resource (i.e. the plant capacity in a given location can be increased by increasing the size of the turbine rotor) but also a resource that yields significant economies of scale (section 3.2.3 and Fig. Q1 of Appendix Q, section Q1).

Although solar is a scalable resource in that the capacity of a PV array can be increased by adding more PV modules, there is no incentive for an investor to do so because no economies of scale benefits could be gained in doing so due to the modular nature of the PV technology (section 3.1.2).

Micro hydro projects on the other hand yield economies of scale but the opportunities are limited because the capacity of a micro hydro project is limited by the hydro resource it self; its available head and the flow rate of water.

The comparative advantage of a wind resource (over hydro and solar) means that there are more opportunities for investors, especially with right infrastructure including state initiatives. As seen in section 8, in order to realise maximum benefits to the investor and the state (assuming that the sate is providing subsidies) based on current technology costs, small and medium grid connected wind turbines should be installed in areas in excess of 7 m/s wind regimes.

Obtaining on site wind data for a small wind energy project is relatively costly considering that wind data needs to be collected over a long period (one-year at least). To this end, it would be useful to have a national wind atlas that could be accessed by the general public free of charge over the internet. The National Institute of Water and Atmosphere (NIWA) intend to prepare a new "wind resource atlas" – down to highly specific wind flow modeling over individual hills. The object of this NIWA project is to provide wind speed data required for wind farm development (NIWA, 2003) and wind turbine manufacturers. If a new wind atlas were to eventuate, availability of the same to the general public as a geographic information system (GIS) would allow a rural farmer to take decisions on the suitability of a wind resource based on GIS data in conjunction with his or her "local knowledge."

From a lines company perspective, having knowledge on the wind resource at different locations[8] in areas served by their network can be used to study the impact of having

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[8] *In a wind atlas what is reported are annual average wind speeds at different geographic locations, which by itself is not sufficient for generating time series wind speed data that is necessary for DG analysis. Apart from the annual average wind speed, four other variables are required for developing time series wind data for a given location; the autocorrelation factor, Weibull k value, the diurnal pattern strength and the hour of peak wind speed (section 6.2.3). Weibull k is strongly correlated with the annual average wind speed (NREL, 2002) and hence can be estimated. The other three parameters can be estimated through local site knowledge. Hence, annual average wind speed provides a good starting point for wind profiling.*

wind turbine generators (WTGs) in different locations with diverse wind regimes. As seen in sections 8.2.1 and 8.3.1.1, in spite of wind being an intermittent resource, any single WTG in a given location provides some capacity support to the network during critical peak periods, if such peak periods occur frequently. It can be argued that several WTGs located in different locations (hence diverse wind energy flow patterns) brings network capacity benefits to a utility company even if critical peak periods are few and far between, due to diversification of risk associated with the intermittent wind source. The computer model can be used to study the impact of 2 WTGs, in two different wind regimes, on network capacity. This was not simulated due to difficulties in obtaining true wind resource data from different locations.[9]

In regard to lines companies facing capacity problems, the availability of wind resource information to public can be thought of as "risk neutral", a lines company too would be able to use such public information. This information can used by a lines company to determine optimal locations to install WTGs for capacity support or to devise competitive payment options for supply of network capacity by other wind energy investors such as rural communities. However, a detailed study is necessary to ascertain the actual impact of WTGs on network capacity support.

9.5.4 Home made distributed energy performance and economic forecasting tools

Although several software packages developed by reputable international agencies are currently available to study the performance and economics of grid connected DG systems, none are capable of studying critical DG issues as relevant to New Zealand. In particular such issues as studying the effects of diverse metering arrangements, effect of time dependant electricity prices, peak shaving and peak lopping are not addressed in the aforementioned software. Indeed this is the reason why a separate computer program was developed to study these issues (section 6).

Industrial Research Limited has developed a distributed energy software package to suit distributed energy requirements of New Zealand. However, this package has yet to be validated against field results (Gardiner, 2002). It is important that home made distributed energy software tools be developed and validated to address New Zealand's distributed energy issues. Having accurate forecasting tools would cause the investor not to add a

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[9] The model algorithms can easily be modified to handle more than two independent wind regimes.

substantial risk premium over the cost of capital, which has a negative impact on the uptake of distributed energy applications in New Zealand (section 9.1.1).

9.5.5 Voltage flicker

In running computer simulations, it was taken for granted that there is no upper limit for connecting generation sources to a distribution feeder. Since wind is an intermittent resource, the electrical power output of the wind turbine generator does fluctuate to such an extent that when fluctuations are taking place in a weak net work, the resulting voltage flicker could affect the quality of service provided.

As seen from Totara Valley simulation results (sections 8.2 and 8.3), it is more economically and socially beneficial to invest in a larger wind turbine unit as a centralized community investment. However if it is necessary to install expensive additional hardware to compensate the voltage flicker the benefit of connecting a larger wind turbine unit could become seriously undermined (section 2.9).

Although there is no industry standard for voltage flicker it is important to identify the extent to which the network impedance affects voltage flicker, given the wind turbine capacity, wind flow pattern, community load flows and network parameters (Fig. 9.2). A weak line is characterised by high network impedance (Z) due to high resistance (R) compared to its reactance (X). A long rural distribution feeder is a weak line and hence the wind turbine active and reactive power flows (P_w and Q_w respectively) can cause network voltage to fluctuate. In the absence of adequate knowledge on voltage flicker, lines companies can make arbitrary decisions that may limit the viability of connecting larger wind turbine generators.

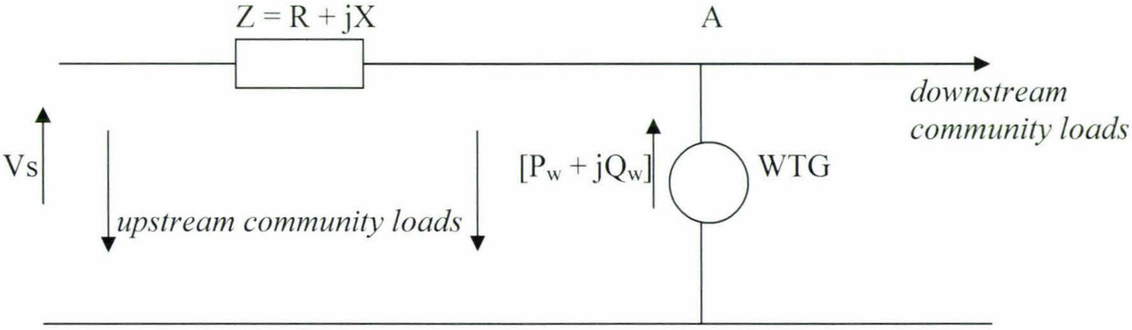

Fig. 9.2: A single line diagram of a wind turbine generator (WTG) connected to a rural distribution feeder

Initial research on voltage flicker may be carried out purely through mathematical modeling. Subsequently, based on the findings, prototype power systems can be replicated in a laboratory setting involving a smaller wind turbine to validate results. These results could serve as a guide to engineers to design any additional hardware to accommodate larger wind turbine generators in a rural network.

It may also be useful to study whether wind diesel hybrids could be used to provide voltage compensation required to minimise flicker (section 8.3.1.3).

CHAPTER 10

Summary and Conclusions

Having simulated and analysed grid connected distributed generation (DG) systems under different dynamic scenarios such as types of technologies used, size and scale of application, types of electricity metering methods, prevailing tariff structures plus price signals from the New Zealand electricity market and lines companies plus state subsidies/taxes, it became evident that opportunities exist for rural grid connected distributed generation investors as well as lines companies who own rural distribution assets to accommodate their individual economic objectives and thereby increase the payoffs of both parties.

In general, smaller scale individual farm based DG applications were found to be less financially viable than community based centralised DG applications due to economies of scale. Micro hydro technologies involving simplified electro mechanical technologies were found to be economic even at individual farm level applications and the method of energy metering did not have a significant effect on the financial viability of the project utilising the right technology. From an investors' viewpoint, small wind turbine generators for individual farm based applications were found to be viable only under wind regimes in excess of 7 m/s with state subsidies, based on current technology costs. In future, based on the combined effect of technological growth and taxes on thermal generation, small-scale wind projects could become more financially viable even if direct subsidies from the state are not realised.

Investing in a standby diesel generator for peak lopping in order to provide capacity to the distribution network during critical peak periods faced by a lines company was found to be an opportunity where economic objectives of both the investor and the lines company could be accommodated together. Wind diesel hybrid DG systems at community scale were found to be attractive provided diesel unit operated as a peak lopping DG unit during critical peak periods.

The research identified a number of problem areas that would influence the investor, the lines company and the state in achieving their respective objectives concerning the uptake of distributed energy. The rural investor's lack of knowledge to evaluate different DG options, absence of direct incentives for small scale renewables and lines company revenue losses due to DG were the most critical issues identified, for which remedial action ought to be implemented by the lines companies and the state were recommended in sections 9.2 through 9.4.

Bearing in mind the fact that 01 April 2013 is end of the obligatory period for lines companies to serve less economical rural network sections, and the lead times involved in the building process of remedial action (e.g. learning curve effects on new technology) it is important that the recommended action be put in place as soon as possible.

10.1 SCOPE FOR FUTURE RESEARCH

A number of research areas were identified and discussed in sections 9.5. These were research on the following areas:

- low cost micro hydro
- wind resource assessment
- diversification of the use of the induction generators
- voltage flicker on weak distribution networks due to wind turbine generators
- dynamic DG performance and economic forecasting tools

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APPENDIX A

The map of the New Zealand electricity grid

(Transpower NZ Ltd., 2002)

Fig. A.1 The map of the New Zealand electricity grid

APPENDIX B

Illustration of some typical distributed energy systems

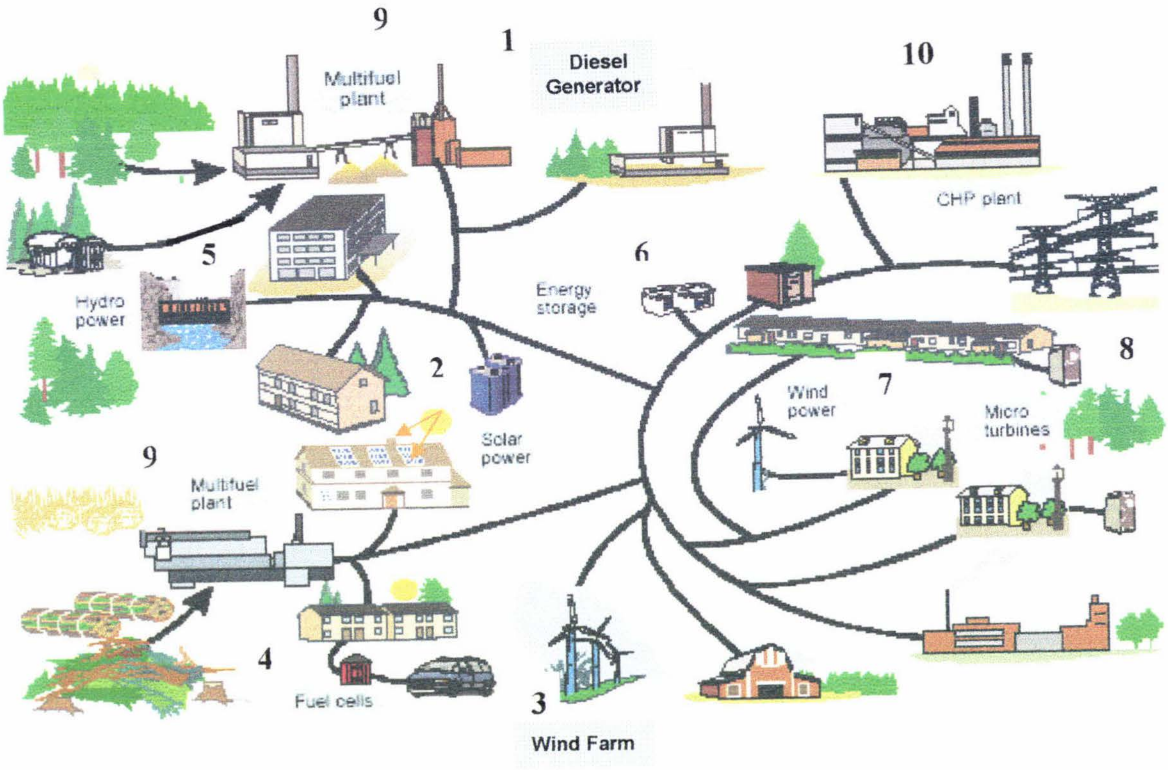

Fig. B.1: Application of distributed energy systems[1]
(Alanen, 2003)

Label No.	Type of the distributed energy system	Details of a typical application
1	Diesel standby generator	A diesel standby generating set belonging to a commercial establishment and connected to the grid during critical peak periods faced by a lines company, as means of capacity support to the distribution network. *Apart from the sale of energy to the retailer, the distributed resource owner receives payments from the lines company for the services provided.*
2	Photovoltaic (PV) array and/or solar thermal	Application A A PV array (consisting of PV modules) on a roof of a dwelling. The DC power output of the array is inverted to AC (through a grid interactive inverter) and connected to the grid. *The distributed resource owner offsets part of the electricity bill due to generation of part of his/her energy requirement for the dwelling.* Application B A solar hot water panel connected to a domestic hot water

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[1] See section 2.2 for definitions.

Label No.	Type of the distributed energy system	Details of a typical application
		cylinder to supply part of the hot water energy requirement. *Heating energy supplied by the solar hot water system shall otherwise have to be met by grid electricity (or gas).*
3	Small wind farm	A community owned small wind farm connected to the local medium voltage (typically 11 kV in New Zealand) distribution network. *The owner derives earnings from the sale of electricity to a retailer. This is analogous to a central power station from the point of view of sales.*
4	Fuel cell	A 5 kW low temperature fuel cell that generates electricity from hydrogen fuel. Hydrogen is generated by electrolysing water by DC produced by a PV array mounted on the roof of a large dwelling. *The electricity generated by the fuel cell is used for charging a high performance battery of a hybrid automobile and for meeting part of the domestic electrical energy requirement (through interfacing the fuel cell output through a grid interactive inverter).*
5	Micro hydro unit	A community owned small hydro plant that functions similar to the wind farm described in (3) above.
6	Battery storage system	A battery storage system owned by a utility that functions similar to a peak lopping standby generator (section 2.6.1.2). The batteries are charged during off peak hours.
7	Single wind turbine generator	A small wind turbine generator (WTG) sited in a country farm. The WTG output which is typically AC, is converted to DC, inverted back to AC (through a grid interactive inverter), and connected to the grid. *The distributed resource owner can offset part of the electricity bill due to generation of part of the energy requirement of the dwelling.*
8	Micro turbine	A 200 kW micro turbine (which is a miniature aero derivative gas turbine) situated in an urban housing complex. *The distributed resource is connected to the grid during*

Note 1 in Page B-3 is replaced with the following note:

All 10 are distributed energy systems but 2 and 9 are not distributed generation systems.

Label No.	Type of the distributed energy system	Details of a typical application
		peak periods where price of electricity delivered remains very high. The distributed resource owner/s in this instance generates electricity at a lower cost than the retail price due to availability of natural gas (the fuel used to power the micro turbine) from the utility at a lower cost.
9	Multi-fuel plant	An industrial boiler which can accommodate a range of dendro (fuel wood) and liquid fossil fuels to fire its burners. The steam derived from the boiler is used for industrial processes.
10	Combined heat and power (CHP) plant	An industrial plant that generates steam for industrial processes and electricity production (through. a steam turbine). The electricity produced is connected to the grid. *A multi-fuel plant can be a CHP plant if both heat (typically steam) and electricity is produced as end products.*

Table B.1: Description of different distributed energy systems

Notes:

(1) Out of the 10 distributed energy systems illustrated in Table B.1, all but system 2 application B (solar hot water) and system 9 (the multi-fuel plant) qualify as distributed resources. All the distributed resources remain grid connected.

System 2 application B (solar hot water) and system 9 (the multi-fuel plant) do not involve electricity generation, storage or control and that is why they cannot be termed as "distributed resources."

(2) Out of the distributed resources described in (1) above, distributed resource 6 is a storage system (Table B.1). In this particular case, since there is no electricity generation through a primary energy source (fossil fuel or renewable resource), there is no distributed generation (DG) involved. All other distributed resources are associated with DG and all DG systems remain grid connected.

(3) There can be hybrid distributed energy systems involving a range of distributed resources in a single application (e.g. a diesel generator and a wind turbine).

APPENDIX C

The role played by a grid connected mini hydro power station in managing power system emergencies

- a Sri Lankan Experience

The role played by a grid connected mini hydro power station in managing power system emergencies - a Sri Lankan Experience

Nihal Jayamaha[1]

I. THE BACKGROUND

Year 1977 marked an important chapter in the political history of Sri Lanka. The right wing United National Party government that swept into power in the general election, made some radical economic reforms that transferred the national economy from a hitherto centrally controlled closed system to a fully liberalised free enterprise system. The results of the economic reforms became obvious in the early 1980s with the growth in the manufacturing and service sectors.

Along with the economic revolution marked the "cultural revolution" in rural Sri Lanka. Although prior to economic reforms majority of rural females in Sri Lanka were employed, they were "unpaid family workers" for the most part supporting the male farmer (husband or father) in low yielding family agricultural pursuits. Economic reforms paved way for several employment opportunities for females, especially in the export oriented apparel industry. Working away from home was no longer regarded as unbecoming for a mother or a daughter. This also triggered females seeking overseas employment in labour intensive industries. Consequently, household income of rural Sri Lankans rose considerably which resulted in more and more dwellings being electrified and more and more electrical appliances being purchased to meet household requirements.[2]

During early to late 1980s, the rise in aggregate household income resulted in certain sections of the country's rural electricity network being subjected to overload in the evenings. The trend continued until the transmission and distribution systems were upgraded. To make matters worse, the country faced energy shortages, which resulted in rotational blackouts island wide during daytime, from 1983 to 1984. This case study describes how a grid connected 6 MW rural grid connected multi purpose Udawalawe mini hydro power station was operated to support network capacity and energy shortages during the above critical period.

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[1] *The author was the engineer in charge at Udawalawe power station from 1983-1985, which was his first appointment since graduating form University of Peradeniya, Kandy, Sri Lanka.*

[2] *Televisions, 2 in 1 music setups and refrigerators topped the list.*

Fig. C.1: The left bank Udawalawe power station in which 2 out of the 3 turbines are located *(Courtesy: Ms Hemali Senevirathne, present engineer in charge at Udawalawe)*

II THE SCOPE OF UDAWALAWE POWER STATION

The Udawalawe power station actually consists of two stations, the left bank station (two of 2 MW turbines) and the right bank station (one of 2 MW turbine) both situated on the Udawalawe reservoir as two submerged power stations (Fig. C.1). The water released through the turbines of the left bank power station is conveyed over the Udawalawe left bank canal through to several irrigation tanks situated downstream. The water released through the turbine of the right bank power station is conveyed over the Udawalawe right bank canal through to one large irrigation tank situated downstream.

Although the water tanks, which were fed by the left bank canal, were designed to irrigate paddy and sugar cultivations, the sugar cultivations (the major agricultural activity planned to harness the left bank waters) were not in place at the time. For this reason, it was not possible to operate even one out of the two turbines on base load as the canal and the downstream tanks would flood otherwise. The maximum steady water flow rate allowed for the left bank canal was approximately 5 m^3/s. This is the water flow rate trough one turbine at 600 kW load (i.e. 30% of the rated capacity) when the reservoir was full (i.e. when the water head was 14.7m). It is also the flow rate trough one turbine at 400 kW load when the reservoir was about $2/3^{rd}$ full (i.e. when the water head was 9.7m), which happens to be the annual average reservoir storage in a typical year. Because of the difficulties in operating a turbine at low load (<400 kW) and the irrigation authorities insisted on a steady water flow all day long due to political reasons, the left bank turbines remained inoperative for the most part up until a strategy was devised to resolve this issue. When the turbines remained inoperative the irrigation water was released trough the turbine bypass valves.

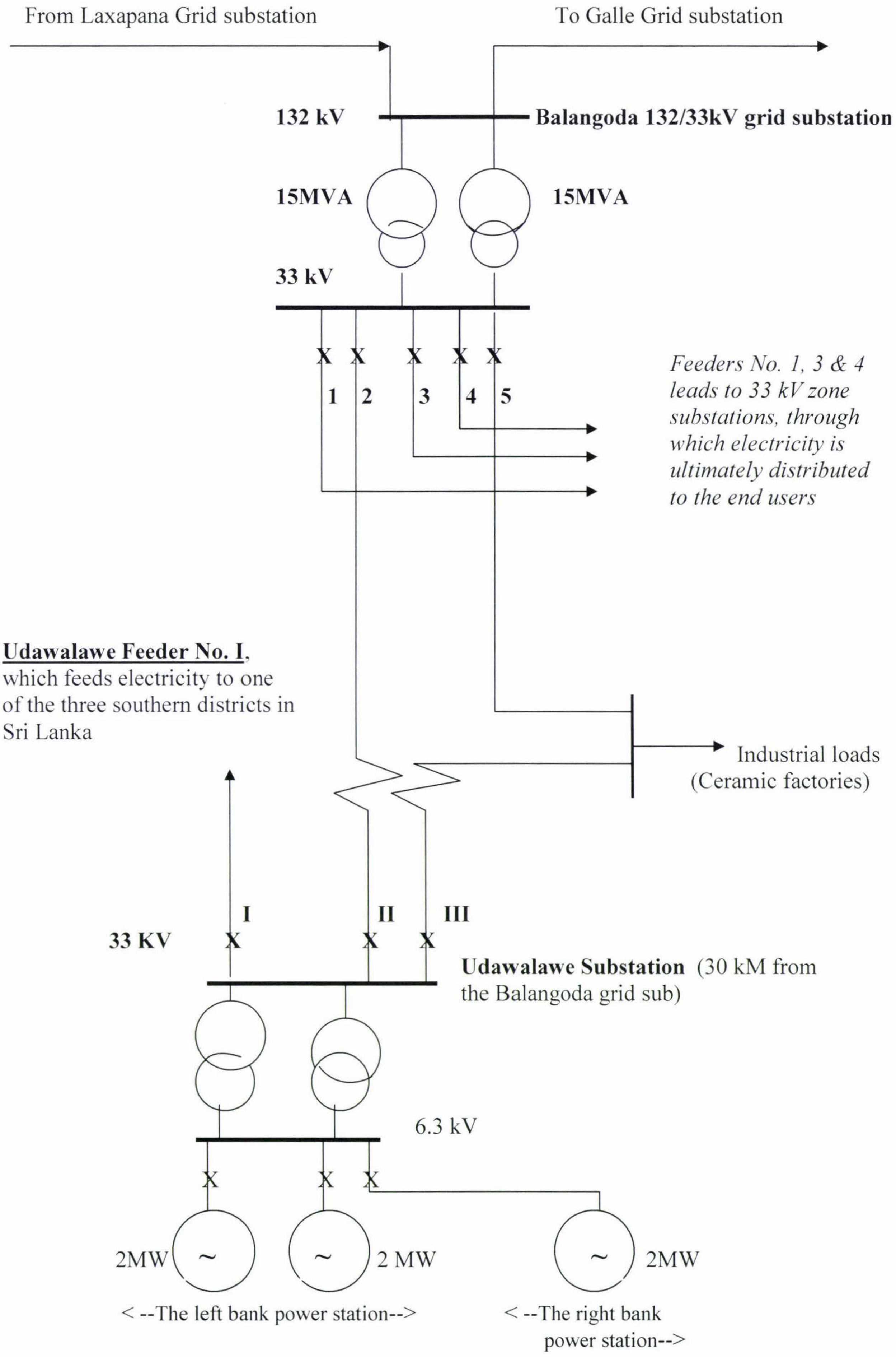
There was no operational problem as far as the turbine on the right bank station was concerned, as the agricultural infrastructure remained fully developed. The monthly plant factors of the right bank station recorded over 80% except in the two paddy harvesting months of the year.

III. THE SPECIFIC POWER SYSTEM EMERGENCIES FACED DURING 1983-1984

Two major power system emergencies were prevalent.

(1) Overloading of inter-bus transformers in the grid substation to which the Udawalawe substation was tied. Balangoda grid substation operator was heavily reliant on Udawalawe generation to keep the two 15 MVA transformers within the allowable loading limits (Fig. C.2). Although all the five 33 kV feeders had sufficient reserve capacity, the transformers never the less got overloaded due to the aggregate load growth of the rural communities. At least 3 MW of Udawalawe generation was necessary during most evenings, to prevent the two transformers being overloaded. This trend continued up until 1989 when the Balangoda substation was finally upgraded.

(2) The islanding the Udawalawe substation and its distribution feeder during the island wide power cuts. The island wide power cuts were effected by selective switching off of the 33 kV feeders from the 24 grid substations of the country, including Balangoda. Due to system control reasons (load flow issues and switching configurations) it was decided that Balangoda feeder 2 and 5 should be switched off concurrently, when effecting power cuts. This meant that either Udawalawe generation plus the load on Udawalawe feeder No.1 had to island (Fig. C.2) or the power station be shutdown. If the power station was to shutdown to prevent islanding, there shall be no water releases through the turbines to the downstream irrigation canals. However the power station was not designed to operate as a stand-alone remote area power supply (RAPS) and hence needed some engineering modifications to meet the power system quality requirements, when operating as a stand-alone system.



Note: *All 33 KV feeder circuit breakers are normally closed, except the circuit breaker on Udawalawe feeder III.*

Fig. C.2: The system configuration

IV. THE STRATEGIES DEVISED TO COPE WITH SYSTEM EMERGENCIES

As regards the transformer overloading problem, it was planned to dispatch between 3 MW to 4 MW of generation during evening peaks, irrespective of the loading level of the inter bus transformers at the Balangoda grid substation. This generally meant that the turbine in the right bank station operated at full capacity (2 MW) while one of the two turbines in the left bank station operated at 50% to 100% capacity during the evening peaks. It also meant that the left bank canal had to be shutdown during daytime. In lieu of having to face the embarrassment of seeing no water release from the left bank canal during daytime, Ceylon Electricity Board, who owned and operated Udawalawe power station, guaranteed the irrigation authorities and the local politicians the following:

- The Ceylon Electricity Board would endeavour to avoid power cuts to some 9,000 electricity users in two southern districts in Sri Lanka. These were all those customers being fed by the Udawalawe 33 kV distribution feeder (Fig. C.2).[3]

- The Ceylon Electricity Board would undertake monitoring water levels of the left bank and right bank canals at 2 strategic points using remote telemetering systems.

As regards the islanding problem during power cuts, it was necessary to make sure that the customers who were islanded were supplied electricity within the specified voltage and frequency. The daytime load on Udawalawe 33 kV distribution feeder was only about 1.8 MW and hence the right bank power station was capable of meeting the MW demand. However, it was observed that the voltage regulation (of the voltage at 33 kV feeder) was poor when one generator was operating as a stand-alone system. In particular, if the feeder voltage dropped for some reason below 32kV, it was very difficult to raise the voltage by increasing the excitation of the generator field winding. The safest strategy in this regard was not to allow the feeder voltage to drop below 32.5 kV, which required the generator field winding be "over exited" all the time.

The following hardware installations were undertaken to facilitate the above tasks.

- Four quadrant power metering at the Udawalawe end of the Udawalawe – Balangoda 33 kV tie lines. This made sure that Udawalawe generators were able to provide as much reactive power injection to the grid as possible, during critical peak

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[3]. *These were the only general customers in the county who did not face power cuts during 1983-1984!*

periods. This also made sure that the Udawalawe operators were able to make the necessary active and reactive power balances just before the power was switched off from Balangoda. This facilitated a very smooth transition from the grid-connected status to stand-alone status.

- Modifying the circuit breaker and the synchronouscope control wiring to accommodate generator synchronising at the 33 kV side (in addition to 6.3 kV synchronizing which already existed), so that when the grid supply was restored from Balangoda, the Udawalawe operator was able to connect the islanded system to the grid supply, without any supply interruption.

- Modifying the station AC and DC auxiliary power supply systems to enable "black start". This was necessary so that the station could start on in its own in the event of a blackout when operating as a stand-alone system.

- Installation of analog telemetering systems that indicated real-time water levels of the canals (in graphical form). The canal water level data were dispatched to the irrigation authorities as proof of meeting the irrigation water release requirements.

V THE RELEVANCE OF THE CASE STUDY TO RURAL NEW ZEALAND

The case study is relevant to rural New Zealand due to two reasons.

- It demonstrates that it is not necessary for the local distribution feeder to get overloaded to warrant network capacity support from distributed generation (DG). In the case of Udawalawe, DG was dispatched to the pressure point in the distribution system (i.e. inter-bus transformers) situated some 30 km away from where DG took place. Similarly, in a New Zealand context, DG could be dispatched through the local distribution line to alleviate overloading of a zone substation transformer, for example.

- It demonstrates that it is possible for grid connected DG to operate as a stand-alone system in an emergency, provided proper measures are taken to meet the operational and safety standards. With modern distributed resources, voltage and frequency control may even be easier than an older technology.

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APPENDIX D

Common low voltage metering schemes used for small scale DG applications in Australia

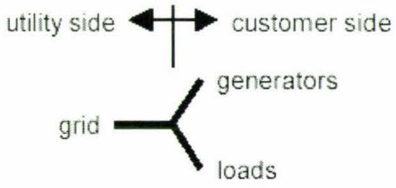
All diagrams and description of the metering schemes depicted in this appendix are based on a report titled, "metering of embedded Generators in Australia," by David Roche (2001).

D.1 Definitions

With regard to metering and billing, a single embedded generator is assumed to be operated in conjunction with a set of conventional loads, both of which are owned by a *customer* who buys electrical energy from (or in some cases sells it to) a *utility* via an electrical distribution network or *grid*. The combined loads and generator are referred to as the customer's *system*. The terms *import* and *export* are used from the perspective of the customer. That is, electrical energy is imported from or exported to the grid. *Gross imports* refers to the total unidirectional flow of electrical energy from the grid to the customer's system. *Exports* refers to the total unidirectional flow of electrical energy from the customer's system to the grid. *Net imports* refers to gross imports less exports. *Gross consumption* refers to the total flow of electrical energy into the customer's load(s). *Generation* refers to the total flow of electrical energy out of the customer's generator. *Net consumption* refers to gross consumption less generation. Net consumption must always equal net imports.

D.2 Categorisation of Metering Schemes

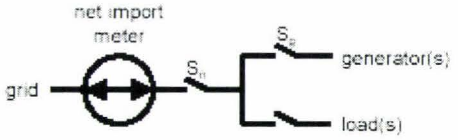
There are many options for metering an electrical system consisting of both loads and generators. In a very generic sense, all the options do have a star circuit topology with three legs joined at a common point where at any time the power in any one leg is equal to the sum of the powers in the other two legs. Such a system can be metered by installing meters either on the grid leg only, or on the generator and load legs as illustrated below.



Metering schemes that come under the purview of the above definitions can be categorised under six schemes, which fall into three broad schemes, the **utility-side metering schemes**, the **customer-side metering schemes** and **hybrid metering schemes**. The three schemes and the associated sub schemes are described in the follow sections.

D.2.1 Utility-side metering schemes

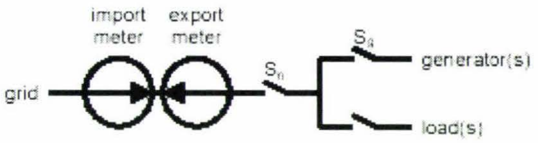
These schemes are based on the view that an embedded generator is a negative load (that is an embedded generator is a demand-side device that influences the load on the grid) and hence it is sufficient to meter only the grid side of the common (star) point. Stated alternatively, utility metering is only relevant for the grid leg, and not for the generator and load legs. Two metering schemes most common under utility-side metering schemes are illustrated under metering schemes 1, 2a and 2b depicted below.



S_n: Normal supply main switch.

S_g: Embedded generator main switch.

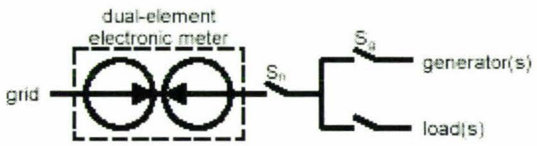
Metering scheme 1: A single bidirectional meter measures net flow of electrical energy between the grid and customer.



S_n: Normal supply main switch.

S_g: Embedded generator main switch.

Metering scheme 2a: Gross imports and exports are separately metered by two unidirectional conventional meters wired in opposite polarity.



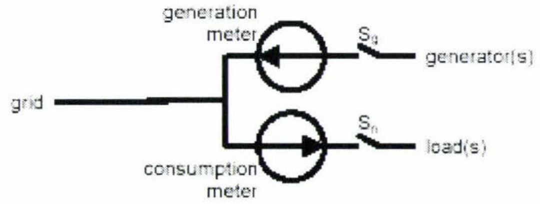
S_n: Normal supply main switch.

S_g: Embedded generator main switch.

Metering scheme 2b: Gross imports and exports are separately metered by a dual-element electronic meter.

D.2.2 Customer-side metering schemes

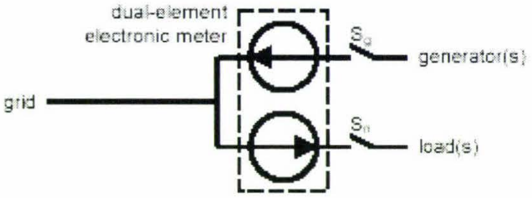
Two customer side metering schemes are illustrated under metering schemes 3a and 3b depicted below. Under these schemes, the customer load(s) and generator(s) are metered as separate systems. Since energy cannot flow directly from the generator leg to the load leg without passing through a meter, different values are measured than in the case of import-export metering. In this case, net consumption (= net imports) is determined by subtracting generation from gross consumption.



S_n: Normal supply main switch.

S_g: Embedded generator main switch.

Metering schemes 3*a*: Generation and gross consumption are separately metered by two unidirectional conventional meters, one on the generator leg and one on the load leg (in some instances, the normal supply main switch is placed on the grid side of the common point).



S_n: Normal supply main switch.

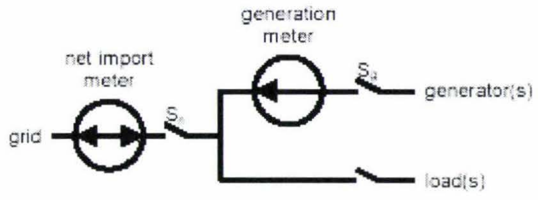
S_g: Embedded generator main switch.

Metering schemes 3*b*: Generation and gross consumption are separately metered by a dual-element electronic meter with one element on the generator leg and the other on the load leg (in some instances, the normal supply main switch is placed on the grid side of the common point).

D.2.3 Hybrid schemes

Hybrid metering systems incorporate a mix of utility-side metering and customer-side metering. The possible hybrid metering combinations are illustrated under metering schemes 4a through 6b. The object of a hybrid metering system is to meter certain demand side responses that are not directly metered by either utility-side metering or customer-side metering. For example, metering scheme 4a can record generation during a certain critical period faced by the utility in order to reward customers who provide capacity to the network. For this purpose, a separate critical period meter reading has to be obtained by activating a separate register by a ripple relay.

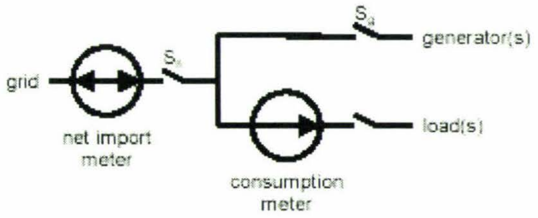
Due to complexities and additional upfront costs involved in metering, hybrid metering systems are not used in domestic scale applications.



S_n: Normal supply main switch.

S_g: Embedded generator main switch.

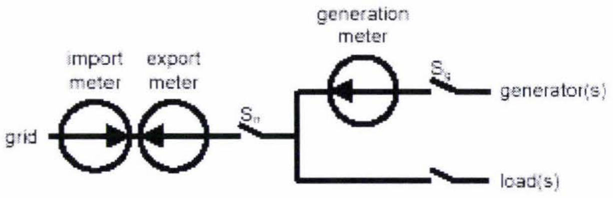
Metering scheme 4a: One bidirectional conventional meter is used to measure net imports and a separate unidirectional meter is used to measure generation.



S_n: Normal supply main switch.

S_g: Embedded generator main switch

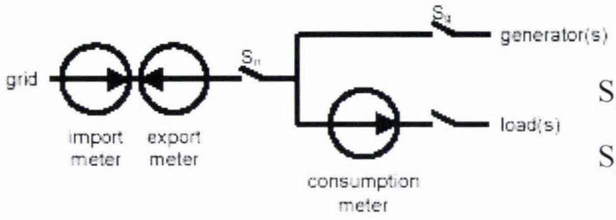
Metering scheme 4b: One bidirectional meter is used to measure net imports and a separate unidirectional conventional meter is used to measure gross consumption.



S_n: Normal supply main switch.

S_g: Embedded generator main switch

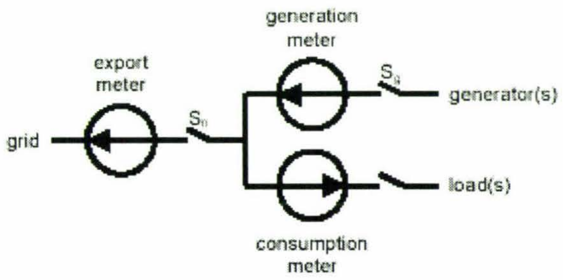
Metering schemes 5*a*: One conventional unidirectional meter is used to measure gross imports, another is used to measure exports and a third is used to measure generation. A variant of this scheme is the replacement of two separate conventional import and export meters by a single dual-element electronic meter.



S_n: Normal supply main switch.

S_g: Embedded generator main switch.

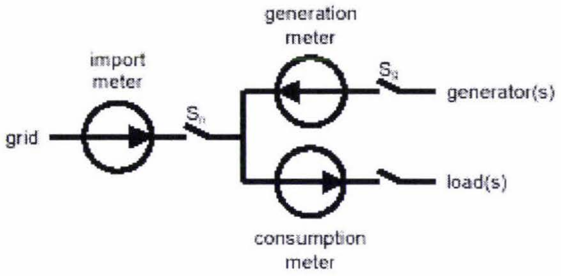
Metering schemes 5*b*: One conventional unidirectional meter is used to measure gross imports, another is used to measure exports and a third is used to measure gross consumption. A variant of this scheme is the replacement of two separate conventional import and export meters by a single dual-element electronic meter.



S_n: Normal supply main switch.

S_g: Embedded generator main switch

Metering schemes 6*a*: One conventional unidirectional meter is used to measure generation, another is used to measure gross consumption and a third is used to measure exports.



S_n: Normal supply main switch.

S_g: Embedded generator main switch.

Metering schemes 6*b*: One conventional unidirectional meter is used to measure generation, another is used to measure gross consumption and a third is used to measure gross imports.

APPENDIX E

11 kV "Country Feeder" Line Parameters for Steady State Power Flow Modeling

The 11 kV distribution line parameters pertaining to country feeder and its Kumeroa spur line

The object of this Appendix is to depict the line resistance and the inductive reactance of the country feeder and its spur line up until the beginning of Kumeroa Zone C area referred to in Fig. 5.1 (Chapter 5). These data enable one to model a typical rural medium voltage distribution feeder for power flows (e.g. line losses) and voltage drops under steady state conditions.

The conductor size, length and the impedance data (resistance and reactance) of different sections of the feeder (Fig. E.1 below) is shown in Table E.1.

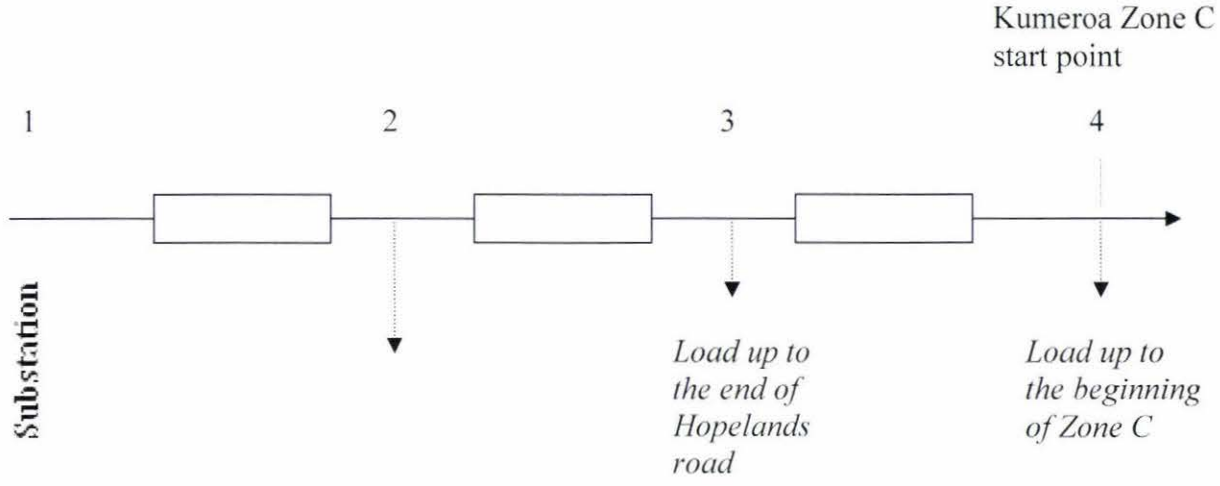


Fig. E.1: The single line diagram of the 11 kV "country feeder and its Kumeroa spur line up until Zone C start point.

Section	Length of the section (km)	Commercial name of the conductor type	Conductor cross sectional area (mm^2)	Nominal overall conductor radius	Estimated conductor AC resistance **(Ω/km)**	Estimated conductor inductive reactance[1] **(Ω/km)**
1-2	5.025	Dog	105 mm^2	7.0 mm	0.40	0.27
2-3	9.875	Ferret	40 mm^2	4.5 mm	0.90	0.31
3-4	2.500	Swan	20 mm^2	3.1 mm	1.70	0.32

Table E.1: The conductor data

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[1] *The inductive reactance is a property of the conductor radius as well as the conductor spacing between each phase. The figures reported in Table D.1 are for a conductor spacing of 0.40 as reported by the cable manufacturer; General Cable New Zealand Limited. The inductive reactance may be calculated for the actual conductor radius and the spacing (expressed as a geometric mean distance) from the standard formulae used in transmission line parameter estimation.*

APPENDIX F

Product and pricing options of ScanPower

Scanpower Limited Schedule of Network Charges
Effective 1 April 2003 to 31 March 2004

D1 Standard Domestic Option 4,533 Customers

Code	Description	New Rate	Old Rate
10	Fixed daily supply charge (per day)	$0.1500	$0.1500
23	Variable network charge (day units per kwh)	$0.0600	$0.0600
24	Variable network charge (night units per kwh)	$0.0400	$0.0400

C1 Standard Commercial Option 1,308 Customers

Code	Description	New Rate	Old Rate
40	Fixed daily supply charge (per day)	$0.7000	$0.7000
28	Variable network charge (day units per kwh)	$0.0600	$0.0600
29	Variable network charge (night units per kwh)	$0.0400	$0.0400

The Standard Commercial option is applicable to commercial installations rated >8kVA with an annual consumption <100,000 kWh.

C1.2 2kVA Commercial Option 482 Customers

Code	Description	New Rate	Old Rate
11	Fixed daily supply charge (per day)	$0.3950	$0.3950
46	Variable network charge (day units per kwh)	$0.0600	$0.0600
47	Variable network charge (night units per kwh)	$0.0400	$0.0400

The 2kVA option is applicable to commercial installations rated <2kVA such as small pumps, electric fences and railway bells.

C1.5 5kVA Commercial Option 425 Customers

Code	Description	New Rate	Old Rate
13	Fixed daily supply charge (per day)	$0.5230	$0.5230
51	Variable network charge (day units per kwh)	$0.0600	$0.0600
52	Variable network charge (night units per kwh)	$0.0400	$0.0400

The 5kVA option is applicable to commercial installations rated <5kVA such as small sheds and workshops.

C3 Commercial Option C3 15 Customers

Code	Description	New Rate	Old Rate
50	Fixed daily supply charge ($ / kva / month)	$2.4000	$2.4000
57	Variable network charge (day units per kwh)	$0.0420	$0.0420
58	Variable network charge (night units per kwh)	$0.0280	$0.0280
133	Corporate Services Charge (per month)	$6.9000	$6.9000

The C3 Commercial option is applicable to commercial installations using between 100,000 and 500,000 kWh per annum.

C4 Commercial Option C4 8 Customers

Code	Description	New Rate	Old Rate
60	Fixed daily supply charge ($ / kva / month)	$2.4000	$2.4000
73	Variable network charge (day units per kwh)	$0.0384	$0.0384
74	Variable network charge (night units per kwh)	$0.0134	$0.0134
65	Maximum demand charge (June, July, August - peak kva)	$4.0000	$4.0000
134	Corporate Services Charge (per month)	$6.9000	$6.9000

The C4 Commercial option is applicable to commercial installations using between 500,000 and 2,000,000 kWh per annum.

C5 Commercial Option C5 2 Customers

Code	Description	New Rate	Old Rate
70	Fixed daily supply charge ($ / kva / month)	$2.4000	$2.4000
78	Variable network charge (day units per kwh)	$0.0384	$0.0384
79	Variable network charge (night units per kwh)	$0.0134	$0.0134
75	Maximum demand charge (June, July, August - peak kva)	$4.0000	$4.0000
135	Corporate Services Charge (per month)	$6.9000	$6.9000

The C5 Commercial option is applicable to commercial installations using between 2,000,000 and 3,500,000 kWh per annum.

C6 Commercial Option C6 1 Customer

Code	Description	New Rate	Old Rate
71	Fixed daily supply charge ($ / kva / month)	$3.8000	$3.8000
82	Variable network charge (day units per kwh)	$0.02277	$0.02277
83	Variable network charge (night units per kwh)	$0.007277	$0.007277
85	Maximum demand charge (June, July, August - peak kva)	$3.6740	$3.6740
136	Corporate Services Charge (per month)	$6.9000	$6.9000

The C6 Commercial option is applicable to commercial installations using over 3,500,000 kWh per annum.

Miscellaneous Charges

Code	Description	New Rate	Old Rate
12	Public Lighting Network Supply Charge (per fitting per month)	$1.0000	$1.0000
18	Telecom Boxes (per month per box)	$20.70000	$20.70000
19	Electric Fences (monthly charge - no 400V distribution line)	$6.000000	$6.000000
98	Electric Fences (monthly charge - feed from distribution line)	$8.0000	$8.0000
	Building Services Temporary Supplies (3 months)	$52.5000	$52.5000
	Building Services Temporary Supplies (per month after 3 months)	$22.5000	$22.5000

Transpower Charges

Transpower charges are incorporated into Scanpower network charges and, based on historical calculations, are recovered at an average rate of 2.025 cents per kWh (ex GST).

Definition of Day / Night Charges

The day consumption charges apply to energy used between 7am and 11pm. Night consumption charges apply to energy used between 11pm and 7am.

Typically day consumption accounts for 76% of total electricity consumed on the Scanpower network. The remaining 24% is typically consumed at night.

Line Loss Factors

Code	Loss Factor	Description
LF 1	2.5%	Applicable to single ICP on dedicated feeder
LF 2	7.28%	Applicable to single ICP with 11kV metering
LF 3	8.1%	Applicable to all other installations

LF 1 ICP = 0008500100CABDE
LF 2 ICP = 0008500400CA15G

APPENDIX G

Field notes and work papers related to the selection of the energy metering scheme

From: "nihalpj" <nihalpj@xtra.co.nz>
To: "Roger Brough" <r.brough@irl.cri.nz>
Cc: "Sims, Ralph" <R.E.Sims@massey.ac.nz>
Subject: monitoring
Date: Tuesday, July 23, 2002 7:37 PM

Dear Roger,

The 11kV distribution line supplying electricity to Kumeroa community appears to be a radially fed distribution line. I presume that this is typical of New Zealand Rural electrification schemes, where ring mains distribution is not economically viable? Pl. advise.

So I have visualised the distribution infrastructure of rural NZ distribution schemes to be typically associated with, inter alia, long MV lines (obviously some of them may need regular maintenance due to age), pole mounted MV/LV distribution transformers which feed electricity to just a few house holds per transformer (due to low population density in NZ) and high per consumer labour cost (e.g. due to metering & line maintenance). I will collate some statistics & document it my thesis somewhere!

I think it is a good idea to put across the idea of Scanpower etal bearing the cost of MV metering, if we can convince them that what we do shall be of benefit to them. This is all the more reason why, I think, we need to measure load-flows at a point such as A (pl. refer to my attachment), as it encompasses a wider customer base than Kumeroa (I believe that the 11kV line does not terminate at Kumeroa and that there are several other consumers downstream in other communities). The Kumeroa load will be the load difference between points A&B.

I am planning to takedown the utility energy meter readings (& time of taking the measurement) every time I download the data from the digital equipment! These data I think, will serve me as important control data for my study.

About the pole mounted transformers, I was referring to the utility owned distribution transformers mounted on the poles (& not instrument transfers which have fixed burdens!) to distribute electricity to the consumers. I apologise for the confusion caused. I was trying to think of a way of utilising the available resouces..... mirror imaging 11 KV line to line voltage .... on the presumption that we already have CTs for mirror imaging the 11kV line currents... so that we could measure the kWh flown through the line by multiplying the energy meter readings (indicated at domestic voltage level) by a predetermined multiplication factor! As I have spotted later & indicated to you, what we have for SIEWARDS meters are not CTs, but transducers (light current stuff). So it won't work. I apologise again for the inconvenience caused.

I trust that this clarifies all your concerns.

Look forward to doing the necessary field work.

Best Regards,

Nihal

From: "Roger Brough" <r.brough@irl.cri.nz>
To: "Nihal Jayamaha" <N.P.Jayamaha@massey.ac.nz>
Cc: "Alister Gardiner" <a.gardiner@irl.cri.nz>; "Ralph Sims" <R.E.Sims@massey.ac.nz>
Subject: monitoring
Date: Monday, 22 July 2002 10:08 a.m.

Nihal,

>>>> (a) Time Series Load/Energy consumption data of the energy users, with electric hot water Load/Energy measured separately.

All the kumeroa monitoring has been done by massey, so I would assume that the data you are currently working with is the same as the copies we received.

>>>> (b) Aggregated time series load data (i.e. load data of the entire Kumeroa community).

I could not view your word document, so I am making assumptions about the measurement point.

I agree - we should try to get some community scale load profile data - especially if we are going to try and leverage off any capacity charge reductions. 11kV V/I sensing costs about $10k, so we will need a strong "need" before we act. As you say, sensing current alone is a slightly cheaper option. I propose the following strategy (1) contact scanpower/meridian to see if they would be willing to pay for 11kV sensors (2) rethink our household monitoring so that we can sum the 230V data and approximate the 11kV feeder power, i.e. monitor each transformer sec side.

>>>> Roger, is IRL interested in measuring energy flows at point A? Pl. advise? If so, I think we can work out a way of measuring it with the
>>>> available resources, can't we? What we need from the 11kV side is IR, IB , VRY & VYB. We could possibly mirror image these with the available
>>>> resources (I will draw a vector diagram & confirm later) by making use of one of the 11 kV pole mounted distribution transformers and 2Nos.
>>>> SIEWARDS meter CT clamps & 2 Nos. SIEMENS meters? (3 Phase 3 wire, 2 watt meter method).

I would assume that any pole transformer that is used in monitoring should have no varying loads. are there any?

regards,

roger

From: "Nihal Jayamaha" <nihalpj@xtra.co.nz>
To: "Roger Brough" <r.brough@irl.cri.nz>
Cc: "Sims, Ralph" <R.E.Sims@massey.ac.nz>
Subject: Totara Valley visit on 5/10/02
Date: Wednesday, 9 October 2002 3:10 a.m.

Good morning Roger,

Pl. find enclosed herewith some information that would be of use to you in selecting metering equipment.

1. The proposed metering: My field notes and sketches in connection with the LV distribution system is attached (these are not drawn to scale).

2. PV performance: Poultons' PV generation (for the 10 day duration; 25/09/02 to 05/10/02) has been 106 Wh only, meaning daily average generation has been 10.6 Wh. Skermans' PV during the same duration has done 3kWh, meaning their daily average generation had been 300 Wh, which is more like it!

Will discuss with Ralph about this problem of Poultons' PV under performance and design a test to check the system. Could not find any visual abnormality or shading effect.

Regards,

Nihal

I. FIELD NOTES

Sample Description:

1. Study covers electricity consumption patterns in connection with 3 rural NZ families, Skermans' (Nick & Jan), Smiths' and Poultons. Electricity is consumed for their dwellings as well as their principal economic activities (sheep & beef farming).

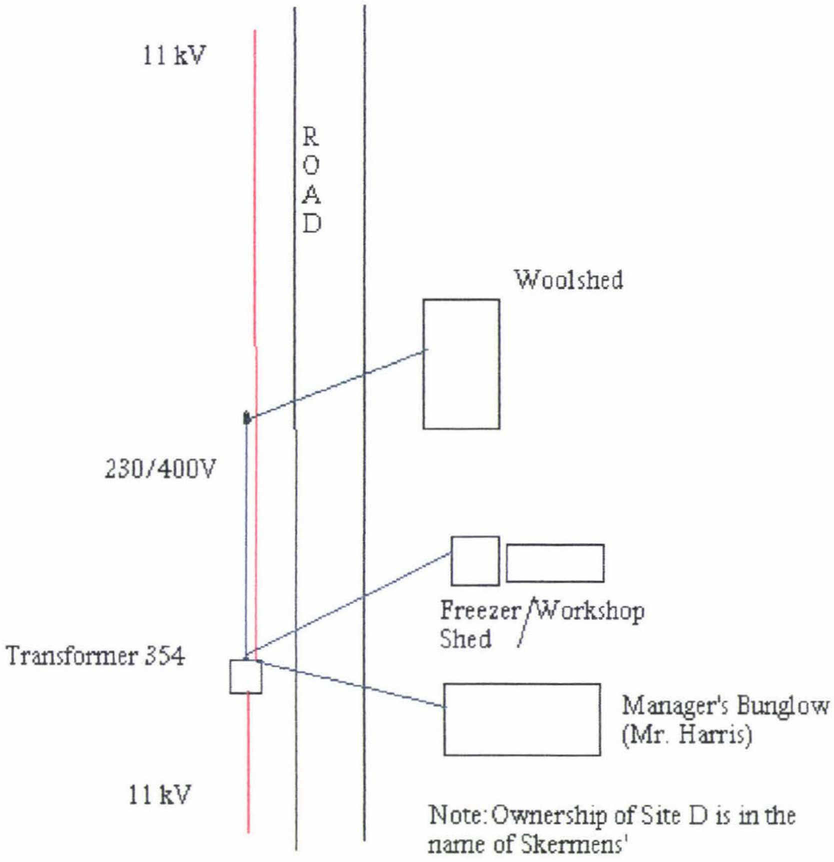
2. As far as electricity is concerned, farming can be identified with a woolshed, freezer shed and a workshop.

3. Poultons' and Smiths' own and manage their own farms while Skermans' employ a farm manager (Nick Skermans does logging elsewhere!).

4. The order of sites found, when approached from Woodville are; Site D, Site C, Site A and Site B.

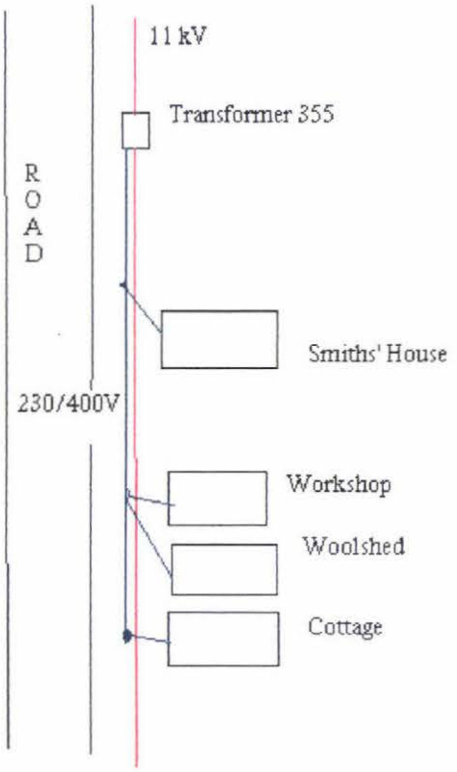
II. SKETCHES OF THE LV DISTRIBUTION SYSTEM OF THE 4 SITES PROPOSED FOR LV BULK METERING

Site D Layout



Field notes and sketches as per my email dt. 9 October 2002 3:10 a.m

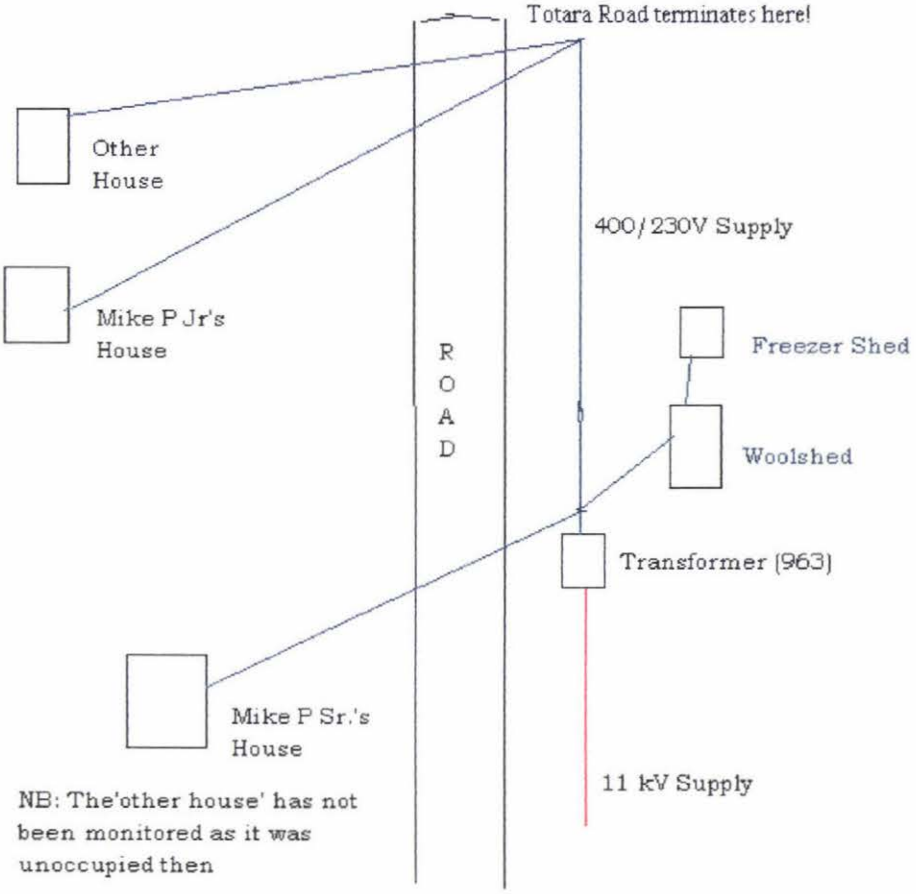
Site A Layout



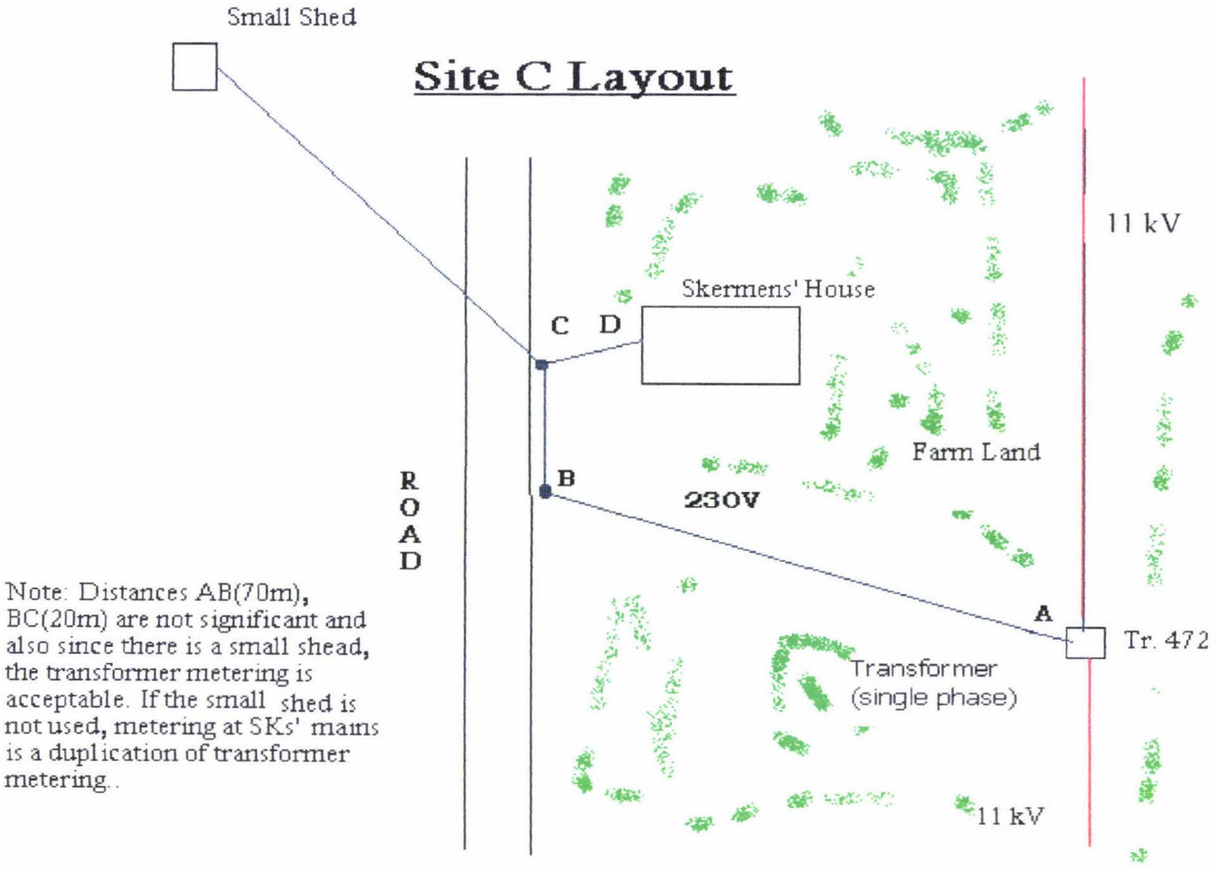
NB: Site A (Smiths') and site B(poultons') are very close in the sense the 2 transformers are only about 350m apart.

Relative positions of the buildings to be confirmed!

Site B Layout



Field notes and sketches as per my email dt. 9 October 2002 3:10 a.m



Note: Distances AB(70m), BC(20m) are not significant and also since there is a small shead, the transformer metering is acceptable. If the small shed is not used, metering at SKs' mains is a duplication of transformer metering..

APPENDIX H

The mathematical models used for the calculation of the solar hot water system performance

Let T_1 be the average temperature (in ^{0}C) of the heat transfer fluid (estimated to be a 5% propylene glycol solution) entering the hot water storage tank heat exchanger and T_2 be the average temperature (in ^{0}C) of the heat transfer fluid (propylene glycol) leaving the hot water storage tank heat exchanger during a particular time interval ΔT (Fig. H.1).

If H is the heat received by the storage tank (in kJ) during the time interval ΔT;

$$H = (\rho Q)C[T_1 - T_2] \qquad \text{Eq. H.1}$$

where, Q = quantity of fluid circulated during time interval ΔT (in l)
ρ = density of the heat transfer fluid (in kg/l)
C = specific heat of the heat transfer fluid (kJ/Kg/^{0}C)

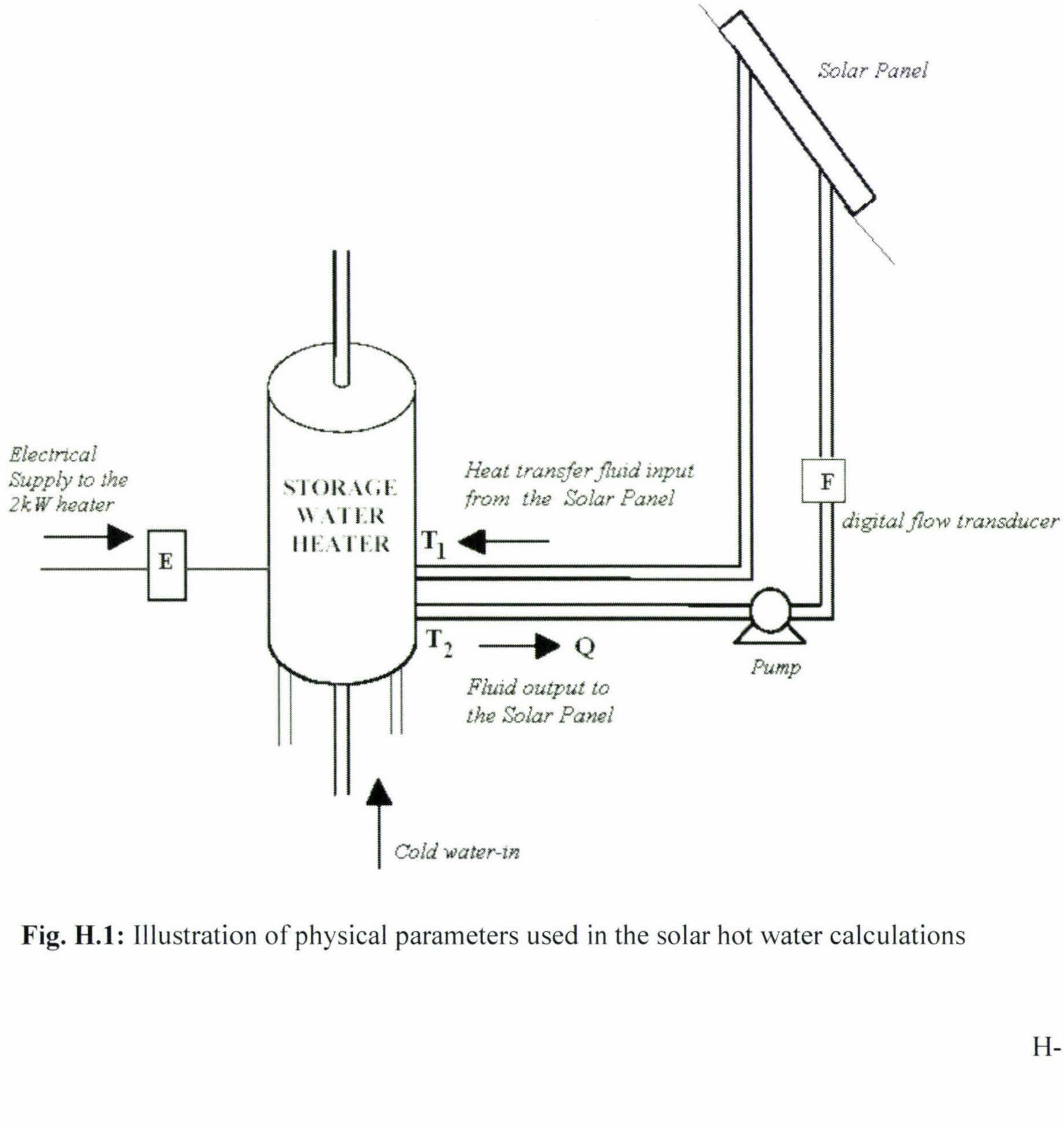


Fig. H.1: Illustration of physical parameters used in the solar hot water calculations

The dependence of density and the specific heat of the propylene glycol solution were assumed to not significantly influenced by its operating temperature. It was also assumed that because the propylene glycol solution was diluted, the density and the specific heat of the solution were approximately equal to that of water.

Hence; $\rho = 1.0$ kg/l

$C = 4.17\ kJ/kg/^{0}C$

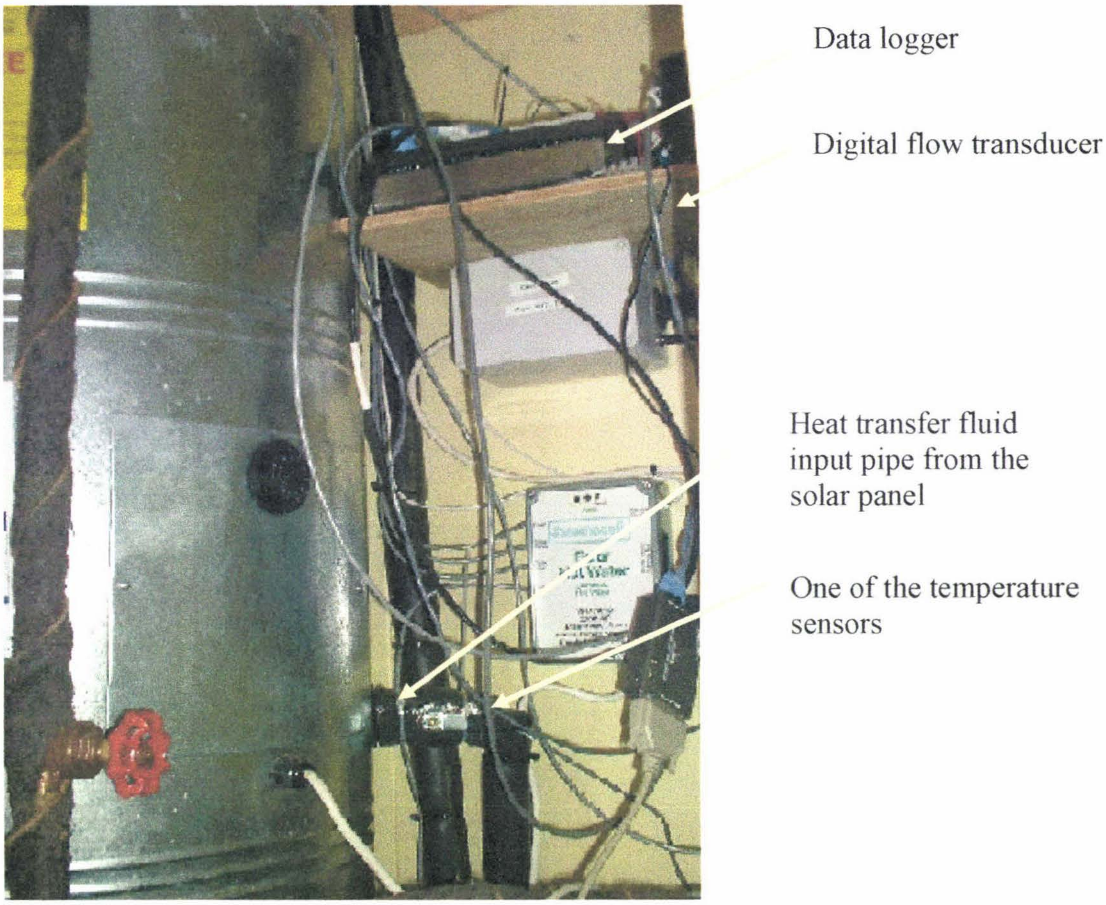


Fig. H.2: A section of the solar hot water monitoring system

It was also assumed that the heat through the piping carrying the heat transfer fluid is negligible.

Hence;

Heat gained by the solar panel = Heat received by the storage tank = H Eq. H.2

APPENDIX I

Field tests done on Solarex MSX 50 PV modules and the OK 4E-100 grid interactive inverter

Part A: The field tests done by the researcher on PV modules

A.1 Subject

Testing of the PV array of farmhouse A at Totara Valley, which is suspected to be defective.

A.2 Objective

To ascertain whether the PV array itself is defective (or otherwise).

A.3 Background

Monitoring done in respect of the grid connected PV array supplied to farmhouse in farm A indicated a daily average energy generation of 10 Wh only, which was substantially less than what is expected. The PV array consists of 2 Nos. Solerex MSX50 PV modules connected in series. A measurement taken in an earlier instant indicated that the inverter current (AC side) is about 30% of the corresponding current of the healthy systems installed in farms B and C.

A.4 Procedure

The PV array was isolated from the ac side and removed from the supporting bracket for testing. Prior to any testing, the panels were visually inspected and the connections at the PV module junction boxes were checked (tightness).

The series connections were removed from the junction boxes of the 2 modules and "Open Circuit Voltages (Voc)", "Short Circuit Currents (Isc)" were recorded for each module separately as well as in series connection. Fig. 1 below illustrates the measuring points for individual modules.

The test was conducted on Saturday 15th Feb 2003. All measurements were taken by levelling the modules on a horizontal plane. The measurements were taken at bright sunlight between 16: 15h to 16: 30h.

As a control measure, the voltage signal from the pyranometer (disconnected from the data logger) was measured via a high impedance mV meter. The pyranometer constant as specified by the manufacturer is 0.2 kW/m^2/mV, which in other words means that the signal level should be 5 mV at 1 sun irradiance.

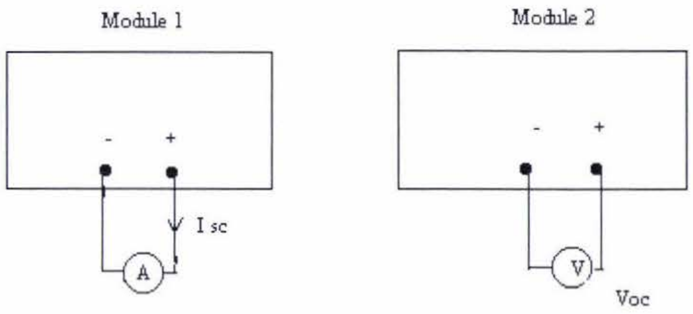


Fig: 1 - Illustration of Voc & Isc

A.5 Observations

The visual inspection & junction box connections (prior to test) do not indicate any abnormality. The key nameplate data (per module). Solerex MSX50, Voc = 21.3V, Isc = 3.26A at STC (i.e. 1000 W/m2 irradiance & cell temperature of 25^0C). NCOT figure were not readable.

The test results are shown in Table-I.1.

Sr.	Item	Voc (V)	Isc (A)	Pyronometer Signal Voltage (mV)
1.	Module 1 only	19.97	2.30	4.48
2.	Module 2 only.	19.89	2.41	
3.	In Series (Module 1 + Module 2)	40.41	2.48	

Table-I.1: *The Test Results*

The Pyronometer signal voltage of 4.48 mV corresponds to a solar irradiance of about 900 W/m^2 (on a horizontal plane), assuming that the pyronometer is properly calibrated at the factory.

A.6 Conclusions

Considering the manufacturer's specifications, measurement inaccuracies, aging etc. it is concluded that there is no defect in the modules. Therefore, the inverter needs to be tested for its operation (see Part B).

Part B: The field test on inverters

B.1 Subject

Testing of the OK 4E-100 inverter supplied with the PV array (consisting of 2 Nos. Solerex MSX50 PV modules) of farmhouse A at Totara Valley, which is suspected to be defective.

B.2 Objective

To ascertain whether the above 100W inverter operates as specified.

B.3 Background

There are number of electrical parameters covered in a grid connected inverter.

If the power outputted by the inverter is below what is expected, then there are two functions to be checked. First, it must be checked whether the inverter faithfully converters DC power to AC power when the grid-connected inverter is fed by a variable DC power source. Second, it must be check whether the inverter operates within specified voltage window, which should be between 190V to 270V AC, according to the Australian national standards for single-phase grid connected inverters. This second test cannot be conducted with Massey University resources because of difficulties in obtaining an autotransformer. The first test was carried out in the manner described in the following section.

B.3 Procedure

The inverter input was fed by a variable DC power source, though an in series ammeter. The voltage was measured across the inverter input terminals. The inverter was connected to AC mains via a digital pulse type energy meter (with a meter constant of 1000 pulses = 1 kWh) and an in series ammeter. The voltage was also measured on the AC side (Fig. I.2). The test was carried out for various DC input power settings. The time interval between two successive energy meter pulses (as indicated by the LED indicated) was recorded for different DC input power settings. The experimental setup used is depicted in Fig. I.3.

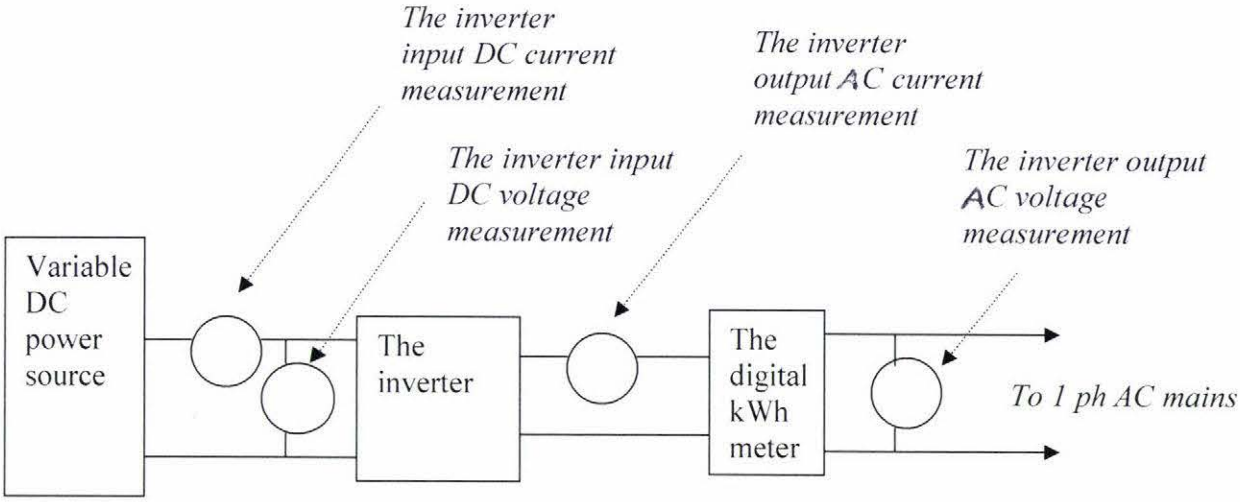


Fig. I.2: The wiring diagram for the inverter test

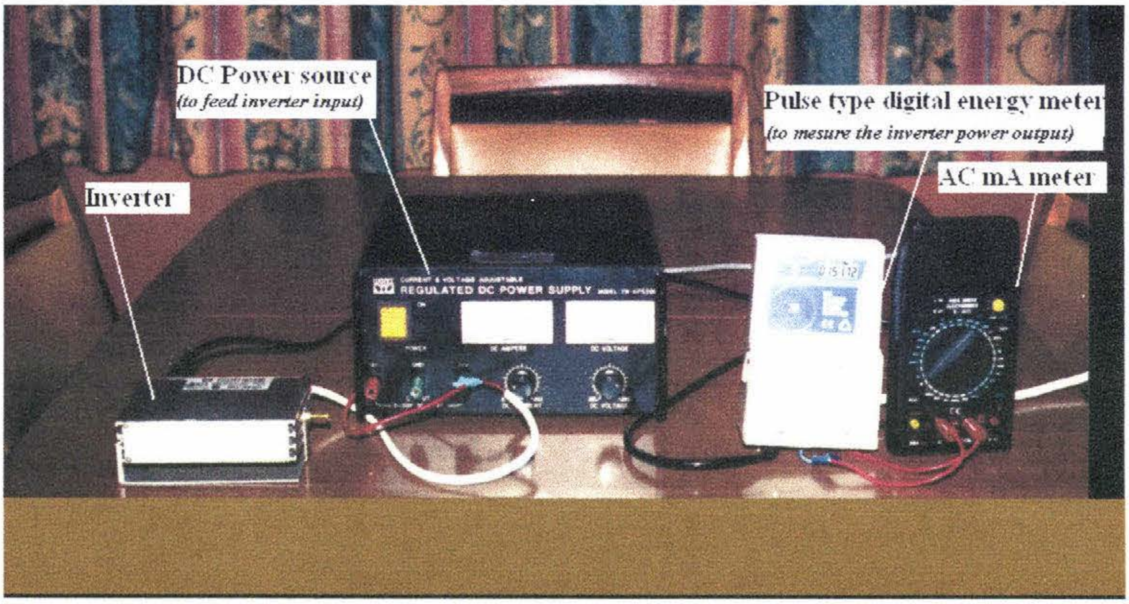


Fig. I.3: The experimental setup used for the inverter test

The raw data collected is depicted in boldface italics in Table I.2.

If the time interval between successive pulses outputted by the energy meter is 'T' seconds for a given DC input power setting, considering the meter constant 1000 pulses 1 = 1 kWh, the real power outputted by the inverter would be (3600/T) Watts. The inverter (real) power output for different input power settings are shown in columns 3 and 8 of Table I.2. The inverter efficiency was calculated dividing output power by input power.

The inverter efficiency values were plotted for different input power settings (Fig. I.4).

B.5 Observations

Input Side (DC)			**Output Side (AC)**					
Voltage (V)	***Current (A)***	Power Input (Watts)	***Voltage (V)***	***Current (mA)***	Apparent power = Voltage* Current	***Energy meter pulse interval (S)***	Real power (W)	Efficiency (%)
0	***0.00***	0.0	***232***	***8.3***	1.9	¶	0.0	0.0
24	***0.62***	14.9	***232***	***62.0***	14.4	¶	14.0	94.1
26	***0.68***	17.7	***232***	***75.0***	17.4	***209***	17.2	97.4
26	***1.00***	26.0	***232***	***115.0***	26.7	***143***	25.2	96.8
25	***2.15***	53.8	***232***	***223.0***	51.7	***70***	51.4	95.7
25	***2.83***	70.8	***232***	***282.0***	65.4	***53***	67.9	96.0
25	***3.28***	82.0	***232***	***316.0***	73.3	***48***	75.0	91.5
Col. (1)	Col. (2)	Col. (3)	Col. (4)	Col. (5)	Col. (6)	Col. (7)	Col. (8)	Col. (9)

(¶ No pulses detected)

Table I.2: Data relevant to varying DC input power settings of the inverter

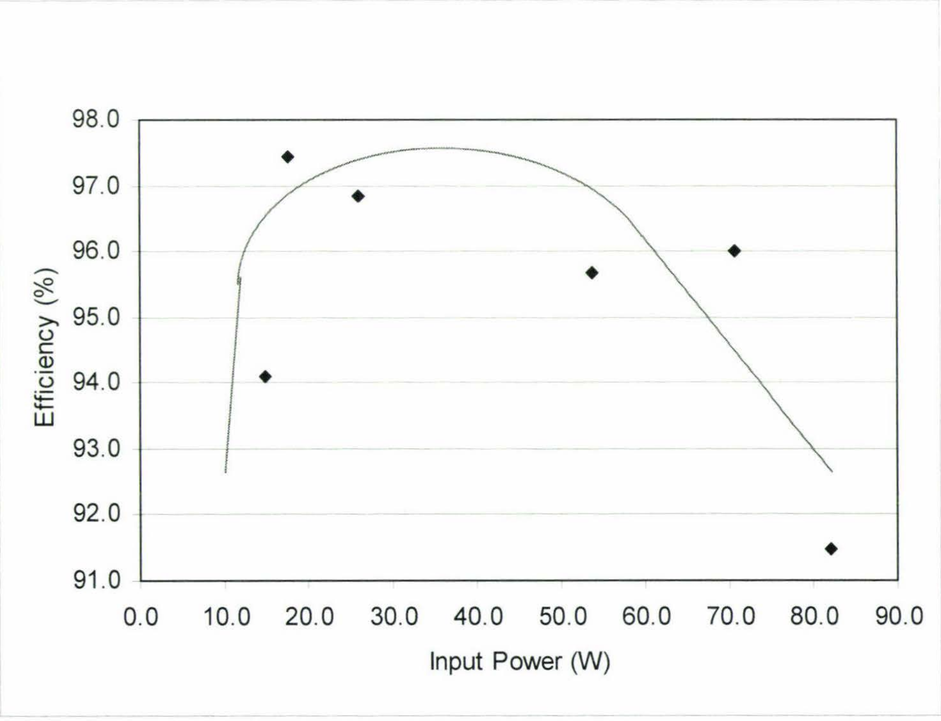


Fig. I.4: The experimental inverter efficiency curve

The efficiency curve fitted for different input power settings (Fig. I.4) suggests that the inverter performs satisfactorily for all input power levels. These are the power levels that would actually be realised in field operations (i.e. when connected to a 100Wp PV array). The efficiency curve also suggested that inverter performed at highest efficiencies between 30 to 70 watts of input power, which would be the input power range the PV array (2 Nos. 50 Wp PV modules) would operate for the most part.

B.6 Conclusions

Based on the above observations it was concluded that the only defect one can suspect is inverter shutdown at higher voltage level experienced by farm A. The inverter was therefore dispatched to Industrial Research Limited, Christchurch, for further testing.

APPENDIX J

Computation of solar insolation on inclined surfaces

J.1 The basic approach

In order to estimate the power produced by PV modules, it is required to determine the insolation on the panel surface. Insolation is a technical term used to refer to solar energy radiation incident on a unit area of a given surface.

In field measurements, almost invariably, the solar insolation is measured on a horizontal surface. This appendix covers the mathematical model used to convert the total solar radiation incident on a horizontal surface to that of an inclined surface. All definitions and mathematical models and description covered in this section were borrowed from Duffie and Beckman (1991).

J.1 The components of solar insolation

The solar insolation is composed of both direct (beam) radiation and diffuse radiation. Direct radiation is the solar radiation received from the sun without having been changed or scattered by the atmosphere. The diffuse radiation (sometimes known as sky radiation) is the solar radiation received from the sun after its direction has been changed by scattering by the atmosphere. Both components of solar insolation depend on the clearness index, the ratio of the insolation on a horizontal surface to the insolation, given a clear sky.

Specifically, the clearness index is defined as the ratio between the actual average irradiance on the horizontal (as provided by the data) to the average irradiance outside the earth's atmosphere. The beam radiation is also a function of the position of the sun in the sky and the physical orientation of the solar panels. The total radiation on the solar panels is a function of the direct, diffuse, and any reflected radiation from the ground (ground reflectance).

J.3 The concept of anisotropic sky and the HDKR model

The ‘anisotropic sky’ is considered to be a complete sky condition that describes all the components of diffused/scattered components of solar radiation. It is distinguished from a more simple sky model known as the ‘isotropic sky’ that assumes that there are only two components of scattered radiation; the diffuse radiation and the ground reflected radiation and that the sum of diffuse radiation from the sky and the ground reflected radiation on the tilted surface is the same, regardless of the orientation of the surface.

The anisotropic sky model on the other hand takes into account the circumsolar diffuse and/or horizon brightening components of scattered radiation on a tilted surface, as illustrated in Fig. J.1.

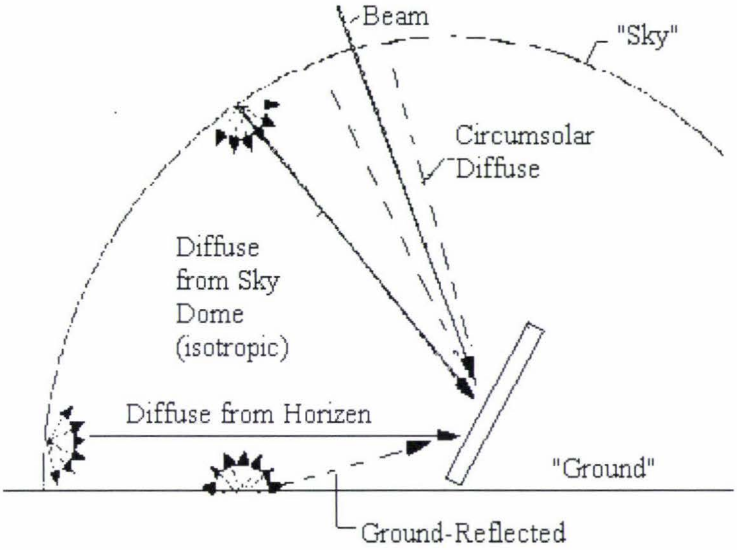


Fig. J.1: The solar radiation components under "anisotropic sky" *(Duffie and Beckman, 1991)*

The Hay et al., (1990) (HDKR)[1] mathematical model calculates the incident radiation on a surface of a tilted panel assuming an anisotropic sky condition. Under this algorithm, the extra-terrestrial radiation is calculated first, based on the Julian day of the year and the site latitude and longitude and time of day the insolation data was collected. This calculation requires converting the data collection time to local solar time. It then establishes the clearness from the global horizontal radiation divided by the extraterrestrial radiation. The clearness index is then used to determine the beam and diffuse components of the global radiation via empirical correlations. Finally, the algorithm determines the radiation on the tilted surface of the panel based on the incident direction of the beam and diffuse solar radiation components and the ground reflectance.

---

1. *HDKR stands for the four authors of the model Hay, Davies, Klucher and Reindl.*

J.3.1 The input variables required for the HDKR model

The following input variables are required for the HDKR model:

- Collector slope angle (β): The angle between the plane of the PV panels and the horizontal.

- Surface azimuth angle (γ): The deviation of the projection on a horizontal plane of the normal to the surface from the local meridian, with zero due south, east negative, and west positive.

- Julian day (n): The day number at the start of the data set, starting with $n = 1$ for the first day of the year. The data is assumed to start at midnight of the day in question.

- Average irradiance on a horizontal surface at each simulation time step ($\bar{G}$), W/m2.

- The hour angle (ω), deg: The angular displacement of the sun east or west of the local meridian due to rotation of the earth on its axis at 15° per hour, morning negative, afternoon positive. The angle ω for each half hour time step is calculated in degrees by multiplying the hours from solar noon by 360/48.

  The following hour angle (which in actual fact is the half hour angle) for each half hour time step is required:

  ω_1 = Hour angle at start of a time step (in deg)
  ω_2 = Hour angle at end of a time step (in deg)

- Site latitude (ø): The angular location north or south of the equator, north positive (deg)

- Site longitude (L): Meridian of the selected site (deg)
- Ground reflectance (ρ_g): The fraction of solar radiation reflected by the ground

All time must be first converted to solar time using the "equation of time" for the difference between solar time and standard time.

$$t_{sol} = t_{std} + \frac{L_{st} - L}{15} + E \qquad \text{Eq. J.1}$$

where

t_{sol} = Solar time, hrs

t_{std} = Standard time, hrs

L_{st} = Standard meridian for the local time zone, deg

L = Longitude of the site under analysis, deg

E = Equation of time correction (hrs)

The equation of time correction, E, is found from:

$$E = 3.82\,[0.000075 + 0.001868 \cos(B) - 0.032077 \sin(B) - 0.014615 \cos(2B) - 0.04089 \sin(2B)] \qquad \text{Eq. J.2}$$

where

$B = (n-1)\ 360/365$ (n being the Julian day as mentioned earlier)

Conversion and use of solar data

The complete equation for finding the irradiance on a tilted surface, $\overline{G}_T$, given the irradiance on a horizontal surface, $\overline{G}$, is

$$\overline{G}_T = (\overline{G}_b + \overline{G}_d A_i)R_b + \overline{G}_d (1 - A_i)(1 + \cos(\beta))(1 + f \sin 3(\beta/2)) + \overline{G}\rho_g \left[\frac{1 - \cos(\beta)}{2}\right] \qquad \text{Eq. J.3}$$

where

$\overline{G}_b$ = Beam component of the average horizontal irradiance (in W/m^2)

$\overline{G}_d$ = Diffuse component of the average horizontal irradiance (in W/m^2)

A_i = Anisotropy index which is a function of the transmittance of the atmosphere for beam radiation, and is given by $Ai = \overline{G}_b / \overline{G}_0$

R_b = Ratio of beam radiation on tilted surface to that on horizontal

G_0 = Average irradiance outside the earth's atmosphere (in W/m^2)

β = Slope angle of PV panels with respect to horizontal (in deg)

f = Modulating factor = $(\overline{G}_b / \overline{G}_0)^{1/2}$

ρ_g = Ground reflectance

The values needed in Eq. J.3 are found as follows:

The diffuse component of the radiation is calculated first via the correlation of Erbs, *et al* (1982), which gives the fraction of diffuse to total radiation, $\overline{G}_d / \overline{G}$ as a function of the clearness index, k_T, G_0. G_0 is found from:

$$\overline{G}_0 = G_{sc} \left(1 + 0.33 \cos \frac{360\, n}{365} \right) [\cos(\varnothing)\cos(\delta)\cos(\omega) + \sin(\varnothing)\sin(\delta)] \qquad \text{Eq. J.4}$$

where;

G_{sc} = Solar constant (1367 W/m2)

δ = Sun's declination (calculated from $\delta = 23.45 \sin[360\,(284 + n)/365]$ (in deg)

The clearness index is found from:

$$k_T = \overline{G} / \overline{G}_0 \qquad \text{Eq. J.5}$$

The diffuse radiation fraction is then found from k_T.

$$\overline{G}_d / \overline{G} = 1.0 - 0.09\, k_T \quad \text{if } k_T \le 0.22 \qquad \text{Eq. J.6a}$$

$$\overline{G}_d / \overline{G} = 0.9511 - 0.1604\, k_T + 4.388\, k_T^2 - 16.638\, k_T^3 + 12.336\, k_T^4 \quad \text{if } 0.22 < k_T \le 0.80 \qquad \text{Eq. J.6b}$$

$$\overline{G}_d / \overline{G} = 0.165 \quad \text{if } k_T > 0.80 \qquad \text{Eq. J.6c}$$

The beam radiation is obtained by subtracting the diffuse component from the average measured irradiance.

$\overline{G_b} = \overline{G} - \overline{G_d}$

R_b is calculated by the equation

$R_b = \cos(\theta)/\cos(\theta_z)$

where

θ_z = Zenith angle (in deg)

θ = Angle of incidence of beam radiation on surface (in deg)

The zenith angle, which is the angle between the sun's rays and a line perpendicular to the earth's surface, is found from;

$$\cos(\theta_z) = \cos(\emptyset)\cos(\delta)\cos(\omega) + \sin(\emptyset)\sin(\delta)$$

The angle of incidence, which is the angle between the sun's rays and a line perpendicular to the panels, is found from;

$$\begin{aligned}\cos(\theta) = {} & \sin(\delta)\sin(\emptyset)\cos(\beta) - \sin(\delta)\cos(\emptyset)\sin(\beta)\cos(\gamma) \\ & + \cos(\delta)\cos(\emptyset)\cos(\beta)\cos(\omega) - \cos(\delta)\sin(\emptyset)\sin(\beta)\cos(\gamma)\cos(\omega) \\ & + \cos(\delta)\sin(\beta)\sin(\gamma)\sin(\omega)\end{aligned}$$

where

γ = PV array surface azimuth angle (deg)

The surface azimuth angle is the angle between a north facing line (south facing in the Northern Hemisphere) and a line perpendicular to the panel. When the panel perpendicular is west of south, the angle is positive.

APPENDIX K

Mathematical models used in the electricity pricing worksheet

The models and algorithms covered in this appendix refer to items covered under sections 6.2.6 and 6.2.6.1, including Table 6.4 and Fig. 6.10 through Fig.6.13.

The variables used in the algorithms are listed in Table K.1.

Abbreviation	Description
$C_{1,m,d,t}$	Daily half hour spot price in the first year
r	Spot price annual escalation rate (%)
R	Retailer operating margin
C_D	Fixed daily network supply charge
$C_{LC,m,d,t}$	Variable line charge
K_{LC}	Variable line charge rescale factor
$C_{LC,Average}$	Annual average line charge
$C_{RT,m,d,t}$	Variable retail price (first year)
$C_{RT,Average}$	Annual average variable retail price of the first year
$C_{SP,Average}$	Annual average spot price of the first year
K_n	Variable retail price multiplication factor (also sometimes referred to as the avoided grid energy charge multiplication factor)
TM1 (import), $_{m,d,t}$	The half hour kWh import reading, as indicated by the hypothetical tariff meter TM1 (see Fig. L.1, in Appendix L)
C_{MD}	Maximum demand charge
$L_{PW,G}$	Peak winter load on the grid leg (see Fig. L.1)
C_{PP}	Critical peak period charge
A	A dummy variable used to identify a critical peak period A = 1 if a particular half hour interval is a critical peak period = 0 otherwise
C_{LR}	The daily line rental fee
F	The fixed charge of the customer's electricity bill as a fraction of the total
D	The total duration of the critical peak period (hrs)

Table K.1: The variables pertaining to the energy-matching algorithm

The amount of money a customer pays to the retailer for the energy consumed consists of two components; a fixed supply charge that is not affected by demand side activity including the load demand by the customer, and a variable component that is affected by demand side activity. If a customer generating electricity is metered for the load consumed based on an energy meter on the grid leg only, which is always the case in net metering and gross import gross export metering, distributed generation (DG) becomes a demand side activity that affects the variable component of the customer's bill. DG under the above-mentioned metering schemes would enable a customer to avoid all or part of the variable component of moneys paid to the retailer, depending on the level of DG activity.

K.1 The components of the customer's electricity bill for the energy consumed

Fig. K.1 illustrates the components the model considers as electricity charges imposed upon a customer. The retailer-operating margin was computed as a percentage of spot price and it is the return a retailer expects for the risk undertaken to supply the quantity of energy consumed. In net metering, the electricity is billed for energy on a pre arranged tariff rate, as a standard domestic customer. Under these circumstances the retailer-operating margin is expected to be high as the retailer absorbs all the shocks in spot price fluctuations in the electricity market. In TOU metering based on spot prices, it is the customer who absorbs the price shocks and hence the retailer operating margin is expected to be low.

Demand charge 1: Maximum demand charge ($/Max. kVA/month)	C_{MD}
Demand charge 2: Critical peak period demand charge ($/average critical peak period kVA/year)	C_{PP}
Variable line charge ($/kWh)	$C_{LC,m,d,t}$
Fixed daily line supply charge (line rental) ($/day)	C_D
Retailer operating margin (as a % of spot price)	**R**
Energy charges ($/kWh) ≡ *Daily half hour spot price for the first year*	$C_{1,m,d,t}$

Fig. K.1: The assumed components of electricity charges

The MAPE values in Table K.2 are based on the definition given in Eq. 6.4 (page 126). As in the case of load, the model generates half hour spot price data for each half hour of a year (i.e. 17520 values) based on monthly half hour mean spot price and the two variables "daily noise" and "hourly noise." The only difference with the spot prices is that unlike the loads, the daily noise and hourly noise figures are changed from month to month to take into account the more volatile nature of spot price variation.

As in the case of load, using the noise values and mean spot prices the model synthesises spot prices for the whole year (i.e. 17520 values) and then calculates the monthly half hour standard deviations of spot prices (i.e. predicted values) for the 48 half hour intervals. It then computes the error (MAPE) between the computed values of standard deviation and the actual values of standard deviation (based on published data for Haywards GXP for year 2002) with a view to minimise the error. The error minimisation is achieved by adjusting and readjusting the daily and hourly noise values.

The reason for the hourly noise value to become low for March and June can be explained from Fig. 7.2. As evident from Fig. 7.2, the fluctuation of the half hour spot price variation (as defined by the coefficient of variation) for March and June are lower than any other month (being flatter curves). This results in a low hourly noise value for each month.

If the coefficient of variation fluctuates severely (from half-hour to half-hour) then it should result in a high hourly noise (not necessarily a high daily noise). A general observation one could make from Fig. 7.2 is that barring March and June, the coefficient of variation records high values and high fluctuations resulting in high daily noises and high hourly noises respectively.

In calculating the variable retail price, the retailer-operating margin was loaded to the spot price and the variable line charge, as evidenced in the section K.3.

The agreed retail price of a net-metered customer was considered to be the average retail price for the whole year, considering all the 17520 half hour spot prices and variable line charges, given the retailer operating margin.

Also, note that the components of the electricity charges listed in Fig. K.1 is not exhaustive, as different retailers and line companies adopt different pricing methodologies to collect their expected revenue. However, in the main, the items listed in Fig. K.1 is a fair representation of the different price components utilities adopt to charge domestic, small and medium commercial customers.

K.2 Daily half-hour spot price calculation algorithm

The method of daily half-hour spot price calculation based on the monthly half hour mean spot price and the standard deviation is similar to the method of calculation of daily half hour customer load described in section 6.2.2.1. However, it was observed that the use of a daily noise parameter and an hourly noise parameter for the whole year does bring about a considerable error. For this reason, it was decided to use separate daily and hourly noise values for each month. This enables the mean average percentage error (MAPE) to be reduced substantially. The optimum noise values used and the resulting MAPE are shown in Table K.2. The user does not have input the noise values, as the lowest possible MAPE values (for each month) have been determined by trial and error (see Fig. 6.6) and is embedded in the computer model.

Month	Daily noise	Hourly noise	Mean average percentage error[1] (MAPE)
January	0.170	0.180	12.75
February	0.170	0.168	13.42
March	0.100	0.060	65.01
April	0.100	0.170	29.93
May	0.100	0.170	33.66
June	0.050	0.050	19.99
July	0.150	0.170	40.88

Contd./

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[1] *Note that still MAPE is high in certain months. This indicates how difficult it is to predict the half hour spot price by a simple statistical forecasting tool.*

Month	Daily noise	Hourly noise	Mean average percentage error[1] (MAPE)
August	0.100	0.170	46.50
September	0.100	0.170	40.20
October	0.100	0.180	24.07
November	0.100	0.170	30.59
December	0.200	0.270	16.89

Table K.2: Optimum noise parameters used and the corresponding MAPE values

K.3 Daily half-hour variable retail price and variable line charge calculation algorithm

K.3.1 Daily half-hour variable retail price (first year) and its annual average

$$C_{RT,m,d,t} = (1+R)^* C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t} \qquad \text{Eq. K.1}$$

$$\begin{aligned} C_{RT,Average} &= \sum\nolimits_{year} C_{RT,m,d,t}/17520 \\ &= \sum\nolimits_{year} (1+R)^* C_{1,m,d,t}/17520 + \sum\nolimits_{year} K_{LC} * C_{LC,m,d,t}/17520 \end{aligned} \qquad \text{Eq. K.2}$$

K.3.2 Daily half-hour variable line charge and its annual average

$$C_{LC,m,d,t} = K_{LC}{}^* C_{LC,m,d,t} \qquad \text{Eq. K.3}$$

$$\begin{aligned} C_{LC,Average} &= \sum\nolimits_{year} C_{LC,m,d,t}/17520 \\ &= \sum\nolimits_{year} K_{LC} * C_{LC,m,d,t}/17520 \end{aligned} \qquad \text{Eq. K.4}$$

K.4 Retail price escalation calculation algorithm

Since the model assumes that the spot price does escalate annually, the retail price also has to be scaled upwards each year. The variable retail prices in \$/kWh for each year will be given as follows:

Daily half hour retail price in the first year $= (1+R)^* C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}$

Daily half hour retail price in the second year $= (1+R)^*(1+r) * C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}$

Daily half hour retail price in the third year $= (1+R)*(1+r)^2 * C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}$

Daily half hour retail price in the n^th^ year $= (1+R)*(1+r)^{n-1} * C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}$ Eq. K.5

As mentioned earlier, in the case of net metering and gross import gross export metering, the customer is able to avoid all or part of the variable retail charge, depending on the level of generation. The model calculates the avoided retail charge for the first year and adjusts the first year's charge by a scaling factor for the balance 19 years, on account of the retail price escalation (of the variable component). The retail price escalation algorithm first determines the applicable scaling factor for each year and then forwards the same to the *final calculations worksheet,* for its computations.

If $\psi_{m,d,t}$ is the quantity of grid energy avoided every half hour, the customer saves a sum of $\sum_{year} C_{RT,m,d,} * \psi_{m,d,t}$ dollars in the first year. Substituting $C_{RT,m,d}$ with the right hand side of Eq. K.1,

Sum saved by avoiding grid energy in respective years are as follows;

$$1^{st} \text{ year} = \sum_{year} [(1+R)* C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]* \psi_{m,d,t}$$

$$2^{nd} \text{ year} = \sum_{year} [(1+R)* (1+r) *C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]* \psi_{m,d,t}$$

$$n^{th} \text{ year} = \sum_{year} [(1+R)* (1+r)^{n-1} *C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]* \psi_{m,d,t}$$

Now if K_n is the avoided grid energy charge in the n^{th} year, as a factor of the first year's charge,

$$K_n = \frac{\sum_{year} [(1+R)* (1+r)^{n-1} *C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]* \psi_{m,d,t}}{\sum_{year} [(1+R)* C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]* \psi_{m,d,t}}$$

$$= \frac{\sum_{year} [(1+R)*(1+r)^{n-1} *C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]}{\sum_{year} [(1+R)* C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}]}$$

$$= \frac{\sum_{year} (1+R)^{*} (1+r)^{n-1} {}^{*}C_{1,m,d,t} /17520}{\sum_{year} [(1+R)^{*} C_{1,m,d,t} + K_{LC} {}^{*} C_{LC,m,d,t}] /17520} + \frac{\sum_{year} K_{LC} {}^{*} C_{LC,m,d,t}/17520}{\sum_{year} [(1+R)^{*} C_{1,m,d,t} + K_{LC} {}^{*} C_{LC,m,d,t}]/17520}$$

Therefore,

$$K_n = \frac{(1+R)^{*} (1+r)^{n-1} {}^{*} C_{SP,Average}}{C_{RT,Average}} + \frac{C_{LC,Average}}{C_{RT,Average}} \qquad \text{Eq. K.6}$$

Having obtained the first year's annual average spot price and the retail price, from Eq. K.6, the "avoided grid energy charge multiplication factor" was determined for each year, from year 1 to year 20 by varying the value of n from 0 to 19.

K.5 Daily line rental calculation algorithm

The line rental being fixed, DG does not cause the investor to save or forego any cost and to that extent, it has no impact on the viability of a DG project. It is calculated for reference purposes of the user only. The model outputs the line rental for reference purposes only[2]. For this reason, the line rental calculation was only a rough estimation that involved a very simple calculation described below.

It was assumed that the line rental shall be that component of the customer's electricity bill that can not be accounted for \$/kWh energy charge, \$/kWh variable line charge and \$/kVA demand charge (see Fig. K.1). Accordingly, the calculation involved estimation of the above mentioned tangible components of the bill of the customer for the whole year and then estimation of the annual line rental, assuming that it was based on a certain fixed percentage of the aforesaid tangible components.

Now,

Annual (energy charge + variable line charge) ≈ Annual kWh consumption* Annual average variable retail price of the first year.

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[2] *The line rental should not be confused with any charges a lines company may imposed upon DG owners for using the network. This charge, which is usually based on installed capacity, is treated separately as a model input variable.*

The word "each" in line 4, paragraph 1 of page K-7 is deleted as it is misleading. The lines companies normally impose maximum demand charges for all three-winter months June, July and August. The charges are based on the maximum half hour load for each month. The model however picks and uses the maximum half hour load from the half hour load data of the three winter months, although it would have been possible to use maximum loads of each month, since half hour loads for the whole year are synthesised. Since the maximum half hour load of each month is dissimilar, it was assumed that the average value of the maximum demand for the period June, July and August is 90% of the maximum half hour load as picked by the model.

Annual demand charge = Annual critical peak period demand charge + Annual maximum demand charge

Note that a demand charge is imposed upon a customer, it is usually based on only one of the two demand charges mentioned above. It was also assumed that the maximum demand charge shall be imposed on the winter period only form June through August and that it would be 90% of the peak winter load for ~~each of~~ the winter months. It was also assumed that these demand charges would be based on actual tariff meter readings installed at the grid leg (Fig. 6.14) and not based on any metering at the GXP.

Accordingly the annual energy charge + annual variable line charge ≈

$$C_{RT,Average} * \left[\sum_{year} TM1(import)_{m,d,t}\right] \qquad \text{Eq. K.7}$$

$$\text{Annual demand charge} \approx 0.9*3*C_{MD} + (1/D)*C_{PP} * \sum_{year} A*TM1\ (import)_{m,d,t} \qquad \text{Eq. K.8}$$

The calculation of TM1 $(import)_{,m,d,t}$ is shown in Appendix L (see Eq. L.23).

$$\text{Now, } C_{LR} = \frac{F * \left[C_{RT,Average} * E_A + F*0.9*3*C_{MD} + (1/D)*C_{PP} * \sum_{year} A*TM1(import)_{m,d,t}\right]}{(1 - F) * 365} \qquad \text{Eq. K.9}$$

K.6 The conversion formula on the number of peak period days

If N is the number of peak period days of the season, as signaled by the lines company through its ripple control, the conversion formula converts to a seasonal fraction dividing N by 91.25. The figure 91.25 is based on the assumption that the number of days of the 4 seasons of the year is equal (i.e. 91.25 = 365/4). The fraction N/91.25 was used in the *central worksheet* and *final calculations worksheet* for identifying the peak period days.

Because the computer generates numbers between zero and unity at random from a uniform distribution (i.e. a probability distribution where each number is having an equal chance of being drawn through a random trial), the fraction N/91.25 was used to determine the peak period days as explained in Appendices L and M (see page L10 for example).

APPENDIX L

Mathematical models used in the central worksheet

The models and algorithms covered in this appendix refer to items covered under sections 6.2.7 and 6.2.7.1, including Fig. 6.14 and 6.15. The principal function of the *central worksheet*, as mentioned in chapter 6, is to match energy flows on every half-hourly basis and furnish half-hourly load/energy flows through the hypothetical tariff meters TM1, TM2 and TM3 to the *final calculations worksheet* (Fig. 1.1).

The variables used in the algorithms are listed in Table L.1, while the relevant hardware configuration used is depicted in Fig. L.1. As illustrated in Fig. L.1, there are five generation sources which deliver energy to the DC busbar and same number of generation sources which deliver energy to the AC busbar.

The models used in the *central worksheet* assume the following load dispatch protocols:

- All fuelled generator sets (FGSs) shall always operate on critical peak periods at their rated prime capacity.
- The pumped hydro unit shall operate on critical peak periods at its rated capacity, as determined by its operating head and discharge constraints.
- The battery bank shall discharge energy at C_{25} rating of the batteries and that a constant current generator shall make sure that energy is released at a constant current to the DC busbar at 95% energy conversion efficiency all the time, irrespective of the discharge state of the battery. Batteries to discharge energy on critical peak periods only.
- The DC busbar voltage shall be approximately constant at 120V. When larger DC generation sources are involved, obviously, the busbar voltage has to be raised to the next higher level (i.e. 240V DC) due to wiring regulations (e.g. AS 4509 series). However since the model deals with power flows and capacities, it does not actually matter what the actual nominal busbar voltage is. The nominal busbar voltage of 120V is used only to determine the number of in-series and in-parallel PV modules and batteries only.

Abbreviation	Description
$P_{1,m,d,t}$	Total DC power output delivered by category 1 wind turbine generators (WTG) having the 'technology option 1'
$P_{2,m,d,t}$	Total DC power output delivered by the PV array through the maximum power point tracker (MPPT)
$P_{3,m,d,t}$	DC power output delivered by the micro hydro (MH) unit having the 'technology option 1' or 'technology option 2'

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Abbreviation	**Description**
$P_{4,m,d,t}$	Total DC power output delivered by category 1 fuelled generator sets (FGS) having the 'technology option 1'
$P_{5,m,d,t}$	DC power output delivered by the battery bank through the constant current generator
$P_{6,m,d,t}$	Total AC power output delivered by category 1 wind turbine generators having the 'technology option 2'
$P_{7,m,d,t}$	AC power output delivered by category 2 wind turbine generator
$P_{8,m,d,t}$	AC power output delivered by category 2 fuelled generator set
$P_{9,m,d,t}$	AC power output delivered by the micro hydro (MH) unit having the 'technology option 3'
$P_{10,m,d,t}$	AC power output delivered by the pumped hydro unit
$P_{5a,m,d,t}$	AC power drawn by the battery charger when it is operating in energy charging mode (i.e. the power drawn by the battery charger)
$P_{10a,m,d,t}$	AC power drawn by the pumped hydro unit, when operating in energy charging mode (i.e. when it is operating as a water pump)
$V^{l}_{1,m,d,t}$	Average half hourly wind speed at 10m height, for category 1 WTG
$V^{l}_{2,m,d,t}$	Average half hourly wind speed at 10m height, for category 2 WTG
h_1	The rotor axis (hub) height of category 1 WTG
h_2	The rotor axis (hub) height of category 2 WTG
α	Wind shear exponent
$V_{1,m,d,t}$	Average half hourly wind speed at hub height, for category 1 WTG
$V_{2,m,d,t}$	Average half hourly wind speed at hub height, for category 2 WTG
N_{1W}	Number of category 1 WTG
N_{1F}	Number of category 2 WTG
N_{PV}	The number of 50 Wp PV modules in the PV array
$G_{P,m,d,t}$	Total irradiation on the plane of the PV array
$T_{m,d,t}$	Ambient temperature (relevant to the PV array)
P_{1W}	Rated power capacity of category 1 wind turbine generator/s
P_{2W}	Rated power capacity of category 2 wind turbine generator
P_{1F}	Rated prime power capacity of category 1 fuelled generator set/s
P_{2F}	Rated prime power capacity of category 2 fuelled generator set

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Abbreviation	Description
P_{MH}	Rated power capacity of the micro hydro unit
$Q_{m,d,t}$	Flow rate through the micro hydro turbine
H_{MH}	The gross head applicable to the micro hydro turbine
H_L	The total percentage head loss applicable to the micro hydro turbine (assumed to be constant, irrespective of the flow rate)
A	A 'dummy variable' indicating the availability status of a distributed energy resource (DER); A = 1 if a DER is available and A = 0 if not
B	A 'dummy variable' indicating whether the DER technology belongs to a particular technology option. B = 1 if a yes and B = 0 if not
C	A 'dummy variable' indicating whether a dispatchable a DER (i.e. FGS, pumped hydro and battery bank) should operate or not on a given half hour time interval. C = 1 if a yes and C = 0 if not.
D	A 'dummy variable' indicating whether a dispatchable a DER should operate or not on a given half hour time interval on a given day. D = 1 if a yes and D = 0 if not.
η_{MPPT}	The power conversion efficiency of the MPPT (assumed to be constant at all PV array outputs)
η_{MH}	Overall average efficiency of the micro hydro unit including the rectifier unit. The average efficiency is the efficiency corresponding to operation of the unit under annual average flow rate trough the turbine.
η_{FGS}	The full load power conversion efficiency of the rectifier/s of category 1 fuelled generator set/s
η_{BC}	Battery charger power conversion (AC to DC) efficiency (assumed to be constant, irrespective of the charging current)
C_n	Ampere-hour capacity per battery, at a discharge rate of n hours. The model uses C_{10}, C_{25}, and C_{100} values for its algorithms
V_B	Nominal voltage of a battery used (typically, 2V, 6V and 12V)
N_B	Number of parallel battery strings, in the battery bank
H_{PH}	Net head applicable to the pumped hydro unit
t_{PH}	Time taken (in hrs) to deplete a reservoir (termed 'storage hours')
S_{PH}	Total storage capacity of each reservoir (in m^3), which includes a 20% dead storage.
$P_{L,m,d,t}$	Customer load (after any load control)
P_I	Rated power capacity of the inverter (grid interactive type)

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Abbreviation	Description
$P_{I,m,d,t}$	AC power output through the inverter
$P'_{I,m,d,t}$	Power input to the inverter input trough the DC generator bus bar
$X_{m,d,t}$	The inverter loading fraction, which is defined as power input divided by the rated AC power capacity of the inverter

Table L.1: The variables pertaining to the energy matching algorithm

As an alternative to matching energy flows every half hour, the model matches average power flows during each hour, which has the same effect as energy matching as the time interval (0.5 hours) is common to the left hand side and right hand side of the equations used.

All variables that carry a suffix m,d,t are variables whose average value shall change from half hour to half hour.

Use of dummy variables A, B, C, D enables a single equation to be adopted throughout all the 17520 half hour energy matching states of the DER system. For example, the power released from a FGS of category 2 (i.e. > 50kW rated capacity) will always be governed by the equation $P_{8,m,d,t} = A*C*D*P_{2F}$. However $P_{8,m,d,t}$ will not carry a numerical value if any one of the there dummy variables occupy a value zero. By definition, A shall always be zero if there is no FGS (of category 2), C shall always be zero if the FGS is not programmed to run during a particular half hour time interval, and D shall always be zero if a particular day is not a "critical peak period" day. Note that the dummy variable B is not used in the above equation. This is because the technology code of FGS always remains unchanged. This is not the case for all the DG units; for example WTG of category 1 (see Fig. 6.15 for more details).

Now, matching the energy flows though the DC generator busbar;

$$P'_{I,m,d,t} = \sum_{n=1}^{n=5} P_{n,m,d,t} \qquad \text{Eq. L.1}$$

Matching the energy flows though the AC generator busbar;

L.1 Load flow through the tariff meter TM3

The average load (in kW) indicated by the tariff meter TM3 is as follows:

$$TM3_{,m,d,t} = P_{I,m,d,t} + \sum_{n=6}^{n=10} P_{n,m,d,t} \qquad \text{Eq. L.2}$$

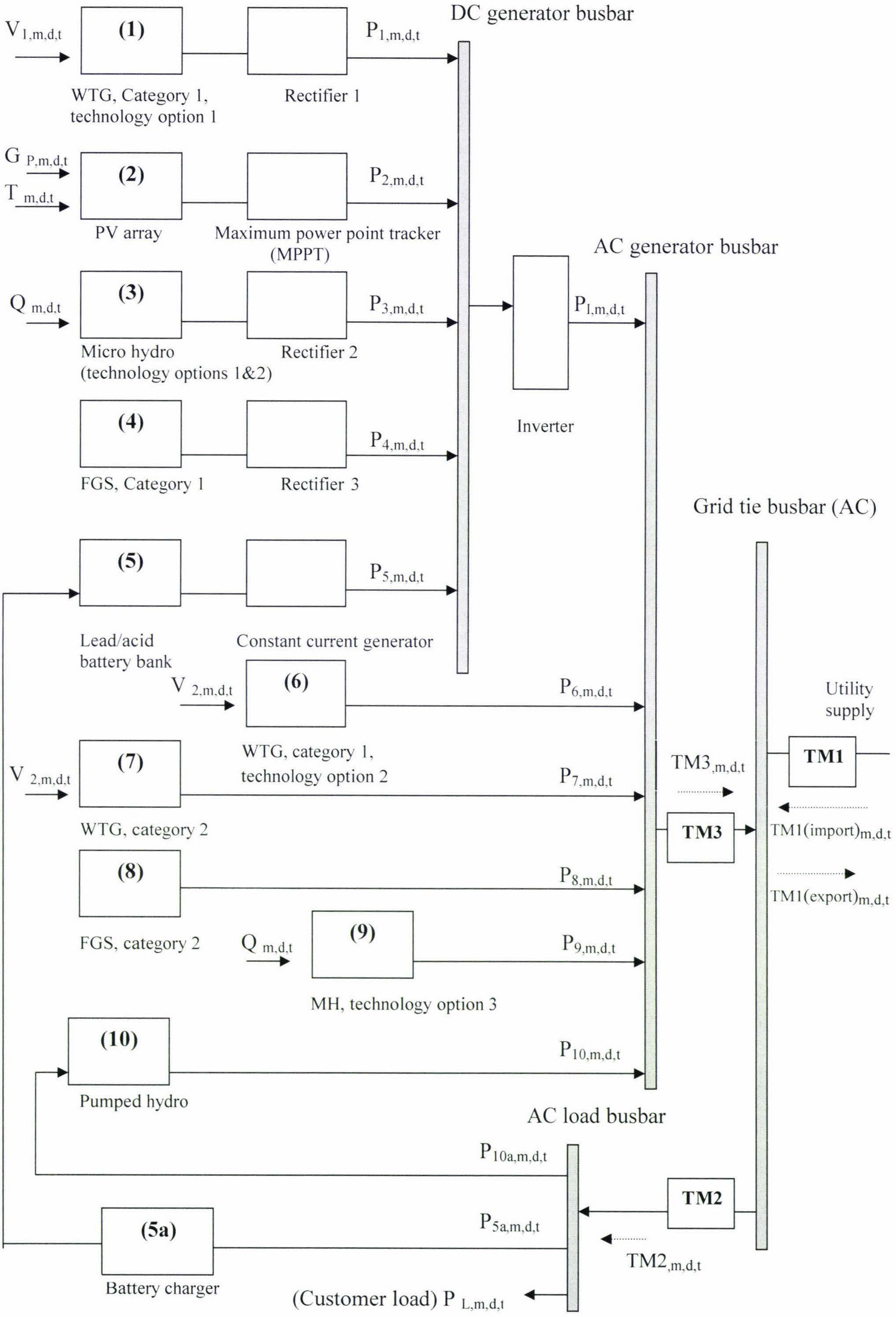

Fig. L.1: The hardware configuration relevant to energy matching

The relationship between $P^{/}_{I,m,d,t}$ and $P_{I,m,d,t}$ can be found by the following polynomial equations, which were derived by OLS regression technique using data of three commercial inverters (2 of 10 kW and 1 of 30 kW). Observation of the scatter plots warranted three "piece-wise smooth curves" (hence three separate regression equations) to accurately represent the inverter power conversion performance depending on its loading fraction. In all three regression equations yielded high R^2 values (>0.95).

$P_{I,m,d,t} / P_I = - 351.560 (X_{m,d,t})^2 + 48.020 X_{m,d,t} - 1.047$; if $0.05 > X_{m,d,t} \geq 0.028$ Eq. L.4a

$P_{I,m,d,t} / P_I = - 38.594 (X_{m,d,t})^2 + 10.709 X_{m,d,t} + 0.049$; if $0.15 \geq X_{m,d,t} \geq 0.05$ Eq. L.4b

$P_{I,m,d,t} / P_I = - 0.424 (X_{m,d,t})^2 + 0.643 X_{m,d,t} - 0.716$; if $1.1 > X_{m,d,t} > 0.15$ Eq. L.4c

$P_{I,m,d,t} / P_I = 0$; for all other $X_{m,d,t}$ values[1] Eq. L.4d

Also by definition; $X_{m,d,t} = P^{/}_{I,m,d,t} / P_I$ Eq. L.5

Note that the model predicts P_I to be; $P_I = \text{Max. } 1.1 * \sum_{n=1}^{n=5} P_{n,m,d,t}$, if the generation mix involves DER sources other than FGS and WTG. If only FGS and/or WTG are involved, the model predicts P_I to be; $P_I = A*N_{1W}* P_{1W} + A*N_{1F}* P_{1F}$

$P_{n,m,d,t}$ values (n =1,2,3,..,10) relevant to Eq. L.1 and L.2 were calculated as follows;

<u>The WTG, category 1, technology option 2</u>:

$P_{1,m,d,t} / A*B*N_{1W}* P_{1W} = - 0.0013 (V_{1,m,d,t})^3 + 0.0340 (V_{1,m,d,t})^2 - 0.1643 V_{1,m,d,t} + 0.2070$; if $3.75 < V_{1,m,d,t} \leq 15$ Eq. L.6a

$P_{1,m,d,t} / A*B*N_{1W}* P_{1W} = 0.0698 (V_{1,m,d,t})^3 - 3.4805 (V_{1,m,d,t})^2 + 57.4028 V_{1,m,d,t} - 312.6178$; if $17.5 > V_{1,m,d,t} > 15$ Eq. L.6b

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[1] *In practical terms, this refers to the inverter not firing due to extreme low input loads or extreme high (over) loads.*

$P_{1,m,d,t} / A*B*N_{1W}* P_{1W} = 0.0064\,(V_{1,m,d,t})^3 - 0.3527\,(V_{1,m,d,t})^2 + 6.4919\,V_{1,m,d,t} - 39.6175$;

if $20 > V_{1,m,d,t} \geq 17.5$ Eq. L.6c

$P_{1,m,d,t} / A*B*N_{1W}* P_{1W} = 0$; for all other $V_{1,m,d,t}$ values Eq. L.6d

The approach adopted in deriving the polynomial equations L.6a through L.6d was similar to that adopted for inverters, except for the fact that data points of power curves of six WTG were used. It should also be noted that the six wind turbines (1 of 3 kW, 1 of 5 kW, 2 of 10 kW and 1 of 20 kW and 1 of 50 kW) had rated wind speeds between 13 m/s and 14 m/s and hence the regression equations may not match actual WTG power curves pertaining to all the wind regimes in New Zealand. What is represented above, in effect, is a generic WTG power curve. Also, note that the value of the dummy variable B, shall be zero, if the technology option of the WTG is 'option 2.'

Conversion of wind speed at reference height (10m) to wind speed at rotor hub height:

According to the power law;

$$\frac{V_{1,m,d,t}}{V^{l}_{1,m,d,t}} = \left[\frac{h1}{10}\right]^{\alpha}$$

Hence; $V_{1,m,d,t} = (V^{l}_{1,m,d,t}) \;\; * h^{\alpha} * 10^{-\alpha}$ Eq. L.7

The PV array;

The algorithm described below in respect of all the calculations in connection with PV array (i.e. Eq.) has been borrowed from Duffie and Beckman (1991). In order to calculate $P_{2,m,d,t}$ from $G_{P,m,d,t}$, $T_{m,d,t}$, N_{PV} and η_{MPPT}, the following additional parameters related to PV modules were introduced.

A_c - Effective area of one PV module; which is 0.4203 m^2 for a Solarex MSX-50 PV module.

T_c – The cell temperature of the PV module

T_{ref} – The reference cell temperature for which PV module performance data is known

η_{mp} – The efficiency of the PV module following a maximum power point tracking algorithm under cell temperature T_c. Accordingly ($\eta_{mp,ref}$ refers to the efficiency of the PV module under a cell temperature of T_{ref}).

$\mu_{P,mp}$ - The maximum power point temperature coefficient

I_{mp} - Module current at the maximum power point

V_{mp} - Module voltage at the maximum power point

μ_{Voc} - The temperature coefficient of open circuit module voltage

τ - The transmittance of the cover that is over the solar cells

α - The fraction of the radiation incident on the surface that is absorbed

Now,

$$P_{2,m,d,t,} = A^* N_{PV} * A_c * G_{P,m,d,t} * \eta_{mp} * \eta_{MPPT} \quad \text{Eq. L.8}$$

In order to compute the known variable η_{mp}, the following calculations are performed.

$$\eta_{mp} = \eta_{mp,ref} + \mu_{P,mp} \ (T_c - T_{ref}) \quad \text{Eq. L.9}$$

Also $\mu_{P,mp} \approx \eta_{mp,ref} * \mu_{Voc} / V_{mp}$ Eq. L.10

By definition; $\eta_{mp} = (V_{mp}^* I_{mp})/A_c^* G_{P,m,d,t}$ Eq. L.11

From data published by the manufacturer, V_{mp}, I_{mp} and μ_{Voc} values for a MSX-50 module under the standard test reference condition of (STC) 1000 W/m2 irradiance are known, and are 17.1V and 2.92A and -85 mV/^{0}C respectively. The cell temperature specified for STC is 25^{0}C.

Hence from Eq. L.11,

$$\eta_{mp,\ ref} = (2.92 * 17.1)/\ 0.4203*1000$$
$$= 0.1188$$

From Eq. L.10

$$\mu_{P,mp} = 0.1188 * (-0.00085) / 17.1$$
$$= -0.00059 \text{ per } {}^0\text{C} \text{ (or per } {}^0\text{K)}.$$

Substituting the above values in Eq. L.9:

$$\eta_{mp} = 0.1188 - 0.00059*(T_c - 25) \qquad \text{Eq. L.11a}$$

The only unknown now is T_c (in ^{0}C).

Also from heat balance equation prescribed by Duffiee and Beckman (1991), considering a module efficiency of η_{cell} under a cell temperature of T_c ;

$$T_c \approx T_{m,d,t} + (G_{P,m,d,t} * \tau * \alpha / U_L) * (1 - \eta_{cell}/0.9) \qquad \text{Eq. L.12}$$

The manufacturer of MSX-50 has specified cell temperate as 47^{0}C under the normal operating cell temperature condition (NOCT), which is the final cell temperature reached under irradiance of 800 W/m2, at 1 m/s wind speed at an ambient temperature of 20^{0}C under no load condition (hence $\eta_{cell} = 0$). Substituting these values in Eq. L.12 we get;

$$47 = 20 + 800 * (\tau * \alpha / U_L) * (1 - 0/0.9)$$

Hence $(\tau * \alpha / U_L) = 0.0338$

Assuming the fraction $(\tau * \alpha / U_L)$ to be a constant for a PV module following a maximum power point tracking (MPPT) algorithm:

$$T_c \approx T_{m,d,t} + (G_{P,m,d,t} * 0.0338) * (1 - \eta_{mp}/0.9) \qquad \text{Eq. L.12a}$$

Since η_{mp} is small compared to 0.9 and is closer to 0.1188, which is $\eta_{mp,\,ref}$, η_{mp} was assumed to be 0.1188. Hence from Eq. 12a,

$$T_c \approx T_{m,d,t} + (G_{P,m,d,t} * 0.0338) * (1 - 0.1188/0.9) = T_{m,d,t} + 0.029 * G_{P,m,d,t} \qquad \text{Eq. L.12b}$$

Substituting T_c determined from Eq. L.12b in Eq. L.11a:

$$\eta_{mp} = 0.1188 - 0.00059*(T_{m,d,t} - 25 + 0.029*G_{P,m,d,t})$$

Substituting the η_{mp} from Eq. L.8:

$$P_{2,m,d,t}, = A*N_{PV}*A_c*G_{P,m,d,t}*(0.1188-0.00059*(T_{m,d,t} - 25 + 0.029*G_{P,m,d,t}))*\eta_{MPPT} \quad \text{Eq. L.13}$$

Micro hydro technology options 1&2

From Eq. 3.5:

$$P_{3,m,d,t}, = A*B*\eta_{MH}*9.81*H_{MH}*(1-H_L/100)*Q_{m,d,t} \quad \text{Eq. L.14}$$

Note that the net head is determined by multiplying the gross head by the loss factor on account of the head loss in the hydraulics. The dummy variable B will be zero if the micro hydro unit chosen belongs to the technology option 3.

Fuelled generator set category 1

$$P_{4,m,d,t}, = A*C*D*P_{1F} \quad \text{Eq. L.15}$$

As explained earlier, no actual generation shall take place if any one of the three dummy variables is equal to zero. The use of the dummy variables C and D is further explained using a practical example. Assume that the FGS is programmed to run on critical peak period days (as signaled by the lines company) during the 91.25 day winter period for 30 minutes.[2] Assume that there is equal chance of any winter day to be a critical peak period day but the actual critical peak period would only occur on the 38th (half hour) time interval. Also, assume that there would be 9 critical peak period days in the season (i.e. 9/91.25 (= 0.0986) in 1 chance).

The computer model assigns a random number between zero and unity for each day. For the above example, the model reckons all winter days having a random number equal or less than 0.0986 to be a critical peak period day and the dummy variable D shall assume a

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[2] *The model assumes that the number of days in a season is equal and hence 91.25 days (notionally) per season.*

The model assumes a taper charging algorithm and hence a proportionally declining charge rates 1.6 X, 1.5X, 1.3X, 1.1X, 1.0X, 0.8X, 0.5X and 0.2 X (page L-11), for 8 sucessive half hour blocks(note that the average charge rate is thus X as defined). The average charge rate X is calculated from Eq. L.18 (page L-12).

Eq. L.18 is derived based kWh energy balance; that is any energy that is discharged (always assumed to be at C_{25} rate) from batteries should be replenished after allowing for efficiency of the battery charging system, which was assumed to be 90% (hence the factor 0.9 in Eq. L.18).

value of unity for all such days. For all other days, D shall assume a value of zero. Furthermore, the dummy variable C will assume a value of unity only on the 38th time interval of winter days (otherwise it shall be zero). This way, once an FGS is introduced as a DG unit (i.e. A = 1), actual power flow will only take place on the desired day at the desired time only.

The battery bank in energy discharging mode

It was assumed that the batteries shall discharge energy at the C_{25} rating. Since this rating is not always specified by the manufacturers, two separate uni-variate regression lines were fitted using publically available data. The two regression lines used to estimate the C_{25} value, based on C_{10} and C_{100} values are as follows:

$$C_{25} = 0.720421 * C_{100} - 1.18149 \quad (R^2 = 0.99) \qquad \text{Eq. L.16a}$$

$$C_{25} = 1.209263 * C_{10} - 0.74352 \quad (R^2 = 0.99) \qquad \text{Eq. L.16b}$$

Considering the nominal busbar voltage of 120V (assumed to be constant during the battery discharge interval) and the N_B number of parallel battery strings in the battery bank,

$$P_{5,m,d,t,} = A*C*D*120*(C_{25}/25)*0.001 \quad \text{(in kW)} \qquad \text{Eq. L.17}$$

The use by the three dummy variables is exactly similar to the use of these variables for the FGS unit explained under Eq. L.15.

The battery bank in energy charging mode

It was assumed that, irrespective of the duration of energy discharge on the critical peak period day, the battery charger would take exactly 4 hours (eight half hour time intervals) to charge the batteries to the original charge level. It was further assumed that the charge rates are adjusted and tapered down to eight discrete charge rates during the eight (half-hour) energy-charging intervals as follows:

1.6X, 1.5X, 1.3 X, 1.1 X, X, 0.8 X, 0.5 X and 0.2 X

X above (in kW) is the average charge rate for the whole of the 4-hour period. Now if the energy discharge took place for a duration of N hours (N = 0.5, 1.0, 1.5 etc.),

$X = 120*(C_{25}/25)*0.001*N/0.9*4$ Eq. L.18

The factor 0.9 used in the denominator, appreciates the fact that more energy needs to be supplied (charged) to the batteries to compensate for the energy lost (discharged). Accordingly, the AC charging power $P_{5a,m,d,t}$ shall be given by:

$P_{5a,m,d,t} = A*D*K/\eta_{BC}$ Eq. L.19

The dummy variables D shall be unity if the day under consideration was a critical peak period day (otherwise it shall be zero). The additional variable K shall occupy a value either 1.6X or 1.5X or 1.3X or 1.1X or X or 0.8X or 0.5X or 0.2X depending on the time interval of the day.

The WTG, category 1, technology option 2

Calculation of $P_{6,m,d,t}$ is identical to the calculation of $P_{1,m,d,t}$ from Eq. L.6a through Eq. L.6.d described earlier.

The WTG, category 2

Calculation of P_7,m,d,t is identical to the calculation of $P_{1,m,d,t}$ from Eq. L.6a through L.6d described earlier, except for the fact that there is no dummy variable B and that the number of WTG shall always be one. Also the wind speeds and rotor hub height should be those applicable to category 2 WTG (see Eq. L.7).

It also follows that the model does not distinguish between medium/large wind turbines and smaller wind turbines as far as the power curve performance is concerned as the same normalized WTG power curve is assumed for small as well as medium/large WTG.[3]

The FGS, category 2

Calculation of P_8,m,d,t is identical to the calculation of $P_{4,m,d,t}$ from Eq. L.15 described earlier.

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[3] *Larger WTG are generally more sturdier and their performance at higher wind speeds is generally steadier compared to their smaller counterparts. Although there would be some error due to assuming one and the same normalized WTG power curve for small as well as medium/large WTG units, it is not expected to materially affect the accuracy of the objective function of the decision model; i.e. predicting the performance and economics of DER configurations for the purpose of identifying optimum configurations.*

Calculation of P_9,m,d,t is identical to the calculation of $P_{3,m,d,t}$ from Eq. L.14 described earlier, except for the fact that the dummy variable B shall be zero if the micro hydro unit chosen belongs to either the technology option 1 or technology option 2.

The pumped hydro unit in energy discharging mode

The pumped hydro unit is expected to operate under constant head and constant flow rate. Assuming a 20% unusable (dead) storage in the reservoirs, the estimated turbine flow rate Q (in l/s) is given by:

$$Q = (0.8*1000*S_{PH})/(t_{PH}*3600)$$

Assuming an overall efficiency of 85%, the turbine power output $P_{10,m,d,t}$ was estimated (in kW)as follows:

$$P_{10,m,d,t} = A*C*D*9.81*0.85*H_{PH}*(0.8*1000*S_{PH})/(t_{PH}*3600*1000) \qquad \text{Eq L.20}$$

The use by the three dummy variables is exactly similar to the use of these variables for the FGS unit explained under Eq. L.15.

The pumped hydro unit in energy charging mode

Assuming an overall efficiency of 85%, the pump power output $P_{10a,m,d,t}$ was estimated (in kW) as follows;

$$P_{10a,m,d,t} = A*C*D*9.81*H_{PH}*(0.8*1000*S_{PH})/(0.85*t_{PH}*3600*1000) \qquad \text{Eq L.21}$$

Note that an identical pumping rate and turbine discharge rate has been assumed, meaning that the pumped hydro unit shall operate in pump mode the same duration as it operated in turbine mode. The dummy variable C in this instance refers to the state of the pump unit. C shall be equal to unity during a time interval, if that time interval is included as a programmed time interval for the pump to operate. The dummy variable D as usual refers to a critical peak period day.

L.2 Load flow through the tariff meter TM2

The average load (in kW) indicated by the tariff meter TM2 is as follows:

$TM2_{m,d,t} = P_{L,m,d,t} + P_{5a,m,d,t} + P_{10a,m,d,t}$ Eq. L.22

L.3 Energy flow through the tariff meter TM1

As mentioned in section 6.2.7.3, the kWh tariff meter TM1 was assumed to be having two separate metering elements; one to indicate the export kWh and the other to indicate the import kWh.

L.3.1 Gross import tariff meter

The import tariff meter reading in kWh is as follows:

$TM1\ (import)_{m,d,t} = 0.5*(TM2_{m,d,t} - TM3_{m,d,t})$; if $TM2_{m,d,t} > TM3_{m,d,t}$

Otherwise, the import reading shall record a zero for that half hour. Eq. L.23

L.3.2 Gross export tariff meter

The export tariff meter reading in kWh is as follows:

$TM1\ (export)_{m,d,t} = 0.5*(TM3_{m,d,t} - TM2_{m,d,t})$; if $TM3_{m,d,t} > TM2_{m,d,t}$

Otherwise, the import reading shall record a zero for that half hour. Eq. L.24

APPENDIX M

Mathematical models used in the final calculations worksheet

The models and algorithms covered in this appendix refer to items covered under sections 6.2.8 and 6.2.8.1 through 6.2.8.1 including Fig. 6.16 and Tables 6.5 and 6.6.

The variables used in the algorithms are listed in table M.1. Note that the variables carrying the m,d,t suffix as usual, are those that could vary from one half hour time interval to another, from day to day and month to month. The variables that are shaded are the ones that are calculated in the *final calculations worksheet*. The other (un shaded) variables are either directly fed to the worksheet or have been imported from other worksheets.

Sr.	**Abbreviation**	**Description**
1	C_I	Initial cost of the project
2	C_j	Cash outflows of the project at the j th year (j = 1,2,....20)
3	$C_{S,j}$	Cash outflows at the j th year due to energy consumption of energy charging devices of the DG system. $C_{S,j}$ is a subset of C_j
4	$R_{1,j}$	Cash receipts for energy inject for the j th year (j = 1,2,...,20)
5	$R_{2,j}$	Avoided cost of grid energy for the j th year (j = 1,2,...,20)
6	R_3	Cash receipts for firm energy or firm capacity provided each year, during the critical peak period
7	R_4	Avoided critical peak period charges and/or maximum demand (MD) charges each year, during the critical peak period
8	R_S	Net salvage money received from sale of project assets at the end of the 20th year.
9	i_I	Investor's weighted average cost of capital. That is the investor's weighted average cost of capital under normal borrowing, assuming that no low interest loans were available from the state .
10	i	The investor's adjusted weighted average cost of capital, taking loan interest state loans into account
11	p	Risk premium (this is premium that applies on the investor's adjusted weighted average cost of capital for project's financial risk)
12	d	Project discount rate
13	A	A dummy variable to identify the presence of a given distributed generation (DG) type; A = 1 if a given DG type is present is preset A = 0 otherwise
14	F_{sub}	The low interest loan supplied by state as a fraction of the initial capital

Sr.	Abbreviation	Description
15	k	Annual interest rate for low interest loan mentioned in 11. above.
16	$C_{1,FGS}$	Cost of one unit fuelled generator set, category 1(i.e. capacity < 50kW)
17	$N_{1,FGS}$	No. of 'category 1' fuelled generator sets
18	$K_{1,FGS}$	Prime power rating (in kW) of a 'category 1' fuelled generator set
19	$C_{1,FGS,system}$	Total initial cost of the 'category 1' fuelled generator system
20	$C_{1,fuel}$	Total annual cost of fuel of 'category 1' fuelled generator sets
21	$C_{1,FGS,O\&M}$	Total annual O&M cost of 'category 1' fuelled generator sets (excluding fuel)
22	$Q_{1,FGS}$	Quantity of fuel consumed by 'category 1' fuelled generator sets (in lit.
23	$H_{1,FGS}$	Operating time of 'category 1' fuelled generator sets (in hours)
24	$C_{2,FGS}$	Cost of a fuelled generator set, category 2 (i.e. capacity $\geq$ 50kW)
25	$K_{2,FGS}$	Prime power rating (in kW) of a 'category 2' fuelled generator set
26	$C_{2,FGS,system}$	Total initial cost of the 'category 2' fuelled generator system
27	$C_{2,fuel}$	Total annual cost of fuel of 'category 2' fuelled generator sets
28	$C_{2,FGS,O\&M}$	Total annual O&M cost of 'category 2' fuelled generator sets (excluding fuel)
29	$Q_{2,FGS}$	Quantity of fuel consumed by 'category 2' fuelled generator sets (in l)
30	$H_{2,FGS}$	Operating time of 'category 2' fuelled generator sets (in hours)
31	$C_{u,f}$	Unit fuel cost ($/l)
32	$C_{1,WTG}$	Cost of one wind turbine generator category 1 (i.e. capacity < 50kW)
33	$N_{1,WTG}$	No. of 'category 1' wind turbine generators
34	$K_{1,WTG}$	Rated capacity (in kW) of a 'category 1' wind turbine generator unit
35	$C_{1,WTG,system}$	Total initial cost of the 'category 1' wind turbine generator system
36	$C_{1,WTG,O\&M}$	Total annual O&M cost of 'category 1' wind turbine generator system
37	$C_{2,WTG}$	Cost of one wind turbine generator category 2 (i.e. capacity < 50kW)
38	$K_{2,WTG}$	Rated capacity (in kW) of a 'category 2' wind turbine generator unit
39	$C_{2,WTG,system}$	Total initial cost of the 'category 2' wind turbine generator system
40	$C_{2,WTG,O\&M}$	Total annual O&M cost of 'category 2' wind turbine generator system

Sr.	Abbreviation	Description
41	C_{MH}	Cost of the micro hydro turbine, generator and the switchgear
42	A_{MH}	A dummy variable used to identify the runner type of the micro hydro unit. If; A_{MH} =1, "Pelton wheel" type A_{MH} =2, "Cross flow" type A_{MH} =3, A reversed engineered centrifugal water pump (low cost technology)
43	K_{MH}	Rated capacity (in kW) of the turbine generator unit
44	$C_{MH,system}$	Total initial cost of the micro hydro system
45	$C_{MH,O\&M}$	Total annual O&M cost of the micro hydro system
46	C_{PV}	Market price of a 50Wp PV module, Mono-Si type
47	N_{PV}	No. of 50 Wp PV modules
48	$C_{PV,system}$	Total initial cost of the PV system
49	$C_{PV,O\&M}$	Total annual O&M cost of the PV system
50	C_{BB}	Cost of one battery
51	V_B	Nominal voltage of a battery
52	N_{BS}	No. of in series batteries per circuit
53	N_{BP}	No. of in parallel circuits
54	C_{25}	C_{25} capacity of a battery (in Ah)
55	$C_{BB,system}$	Total initial cost of the battery bank
56	$C_{BB,O\&M}$	Total annual O&M cost of the battery bank
57	C_{PH}	Cost of the pump/turbine, motor/generator and piping of the pumped hydro system (low cost centrifugal pump & induction motor option)
58	$C_{PH,system}$	Total initial cost of the pumped hydro system
59	$C_{PH,O\&M}$	Total annual O&M cost of the pumped hydro system
60	C_{INV}	Cost of the grid interactive inverter and the control panel
61	$C_{INV,system}$	Total initial cost of the inverter system
62	$C_{INV,O\&M}$	Total annual O&M cost of the inverter system
63	$P_{L,m,d,t}$	Customer load after any load control
64	$P_{5a,m,d,t}$	AC power drawn by the battery charger when it is operating in energy charging mode (i.e. the power drawn by the battery charger)

Sr.	Abbreviation	Description
65	$P_{10a,m,d,t}$	AC power drawn by the pumped hydro unit, when operating in energy charging mode (i.e. when it is operating as a water pump)
65	$P'_{L,m,d,t}$	Customer load before any load control
66	$K_{m,d,t}$	The fraction of the customer load $P'_{L,m,d,t}$ that could be shed by the customer, in the event of a critical peak period signal (also see 67)
67	$a_{m,d,t}$	A dummy variable that will occupy a value of unity, if a particular time interval of the day was a critical peak period (as signaled by the lines company). Otherwise, the value of the dummy variable shall be zero.
68	$TM1(import)_{m,d,t}$	The import tariff reading of TM1 in kWh
69	$TM1(export)_{m,d,t}$	The export tariff reading of TM1 in kWh
70	$TM2_{m,d,t}$	The average load (in kW) indicated by the tariff meter TM2
71	$TM3_{m,d,t}$	The average load (in kW) indicated by the tariff meter TM3
72	$C_{1,m,d,t}$	Daily half hour spot price in the first year ($/kWh)
73	r	Spot price annual escalation rate (%)
74	$C_{RT,m,d,t}$	Daily half hour variable retail price in the first year ($/kWh)
75	K_j	Avoided grid energy charge multiplication factor for the j^{th} year (see Eq. K.6 of Appendix K)
76	C_{FP1}	The amount received from the lines company for per unit firm capacity provided during critical peak periods ($/average kVA/yr)
77	C_{FP2}	The amount received from the lines company for per unit firm energy provided during critical peak periods ($/kWh/yr). Note that C_{FP1} and C_{FP2} cannot exist simultaneously
78	X_1	A dummy variable to identify a payment scenario on firm capacity (see 76 above) If the payment basis is in firm capacity, then $X_1 = 1$, otherwise $X_1 = 0$
79	X_2	A dummy variable to identify a payment scenario on firm energy (see 77 above) If the payment basis is in firm energy, then $X_2 = 1$, otherwise $X_2 = 0$
80	C_{PP}	Critical peak period price ($/average kWh/year)

Sr.	Abbreviation	Description
81	C_{MD}	The maximum demand charge
82	X_3	A dummy variable to identify a net metering arrangement If the metering arrangement is net metering, then $X_3 = 1$, otherwise $X_3 = 0$
83	X_4	A dummy variable to identify a "gross import/gross export metering arrangement" If the metering arrangement is "gross import/gross export", then $X_4 = 1$, otherwise $X_4 = 0$
84	X_5	A dummy variable to identify a "separate generation (& load) metering arrangement" If the metering arrangement is "separate generation (& load) metering", then $X_5 = 1$, otherwise $X_5 = 0$
85	X_6	A dummy variable to identify whether peak shaving systems have been put in place by the customer to reduce critical peak period charges If yes, then $X_6 = 1$, otherwise $X_6 = 0$
86	X_7	A dummy variable to identify whether a separate ripple activated meter has been put in place to record kWh injection to the grid during critical peak periods, in respect of a net metered customer If yes, then $X_7 = 1$, otherwise $X_7 = 0$
87	X_8	A dummy variable to identify whether a separate ripple activated meter has been put in place to record kWh consumption from the grid during critical peak periods, in respect of a net metered customer If yes, then $X_8 = 1$, otherwise $X_8 = 0$
88	X_9	A dummy variable to identify whether maximum demand metering is in place If yes, then $X_9 = 1$,

Sr.	Abbreviation	Description
		otherwise $X_9 = 0$
89	R_S	Retail price rescale factor for year end settlement for excess generation, in respect of net metered customers (see Table 6.4 in Chapter 6)

Table M.1: The variables pertaining to the project investment appraisal

M.1 ASSUMPTIONS ON SOFT LOANS AND THE DISCOUNT RATE

The model allows analysing the impact of state subsidies based on the assumption that a state subsidy can be represented by a single variable "low interest loan" afforded by the state for capital investment in renewable energy DG projects. The interest rate of the soft loan is assumed to be considerably less than commercial rates, thereby affecting the investor's final weighted of average cost of capital (also called the adjusted weighted average cost of capital).

Now, considering the relative weight of the total capital to the capital provided by the soft loan,

$$i = (1-F_{sub})*i_1 + F_{sub}*k \qquad \text{Eq. M.1.a}$$

Since the project's discount rate is equal to the investor's adjusted cost of capital plus a premium for risk;

$$d = i + p \qquad \text{Eq. M.1.b}$$

M.2 BASIS OF THE PROJECT FINANCIAL VIABILITY CALCULATION

In order to calculate the financial feasibility of the project the initial investment of the project, annual cash outflows, the cash received each year as a result of operating the project and any salvage value at the end of the lifecycle of the project (i.e. after the twentieth year) are needed.

Section M.4 describes the method of calculation of the initial investment of the project and the annual cash outflows.

The income received each year as a result of operating the project can be due to one or more of the following:

$R_{1,j}$	Cash receipts for energy inject for the j^th year (j = 1,2,…,20)
$R_{2,j}$	Avoided cost of grid energy for the j^th year (j = 1,2,…,20)
R_3	Cash receipts for firm energy or firm capacity provided each year, during the critical peak period
R_4	Avoided peak period charges and/or the maximum demand (MD) charges each year, during the critical peak period

The proper use of the dummy variables to identify the DG configuration and available price signals will ensure that only the appropriate components are calculated for a given situation. For example if the metering system used was "separate generation (and load) metering," then there is no avoided cost of grid energy because there is no reduction of grid electricity on the customer loads.

M.3 CALCULATION OF THE PROJECT FINANCIAL INDICATORS

Fig. M.1 depicts the relevant cash inflows and outflows of the project. Downward pointing arrows towards the horizontal bar show all cash inflows for each year while downward pointing arrows away from the horizontal bar show all cash outflows for each year.

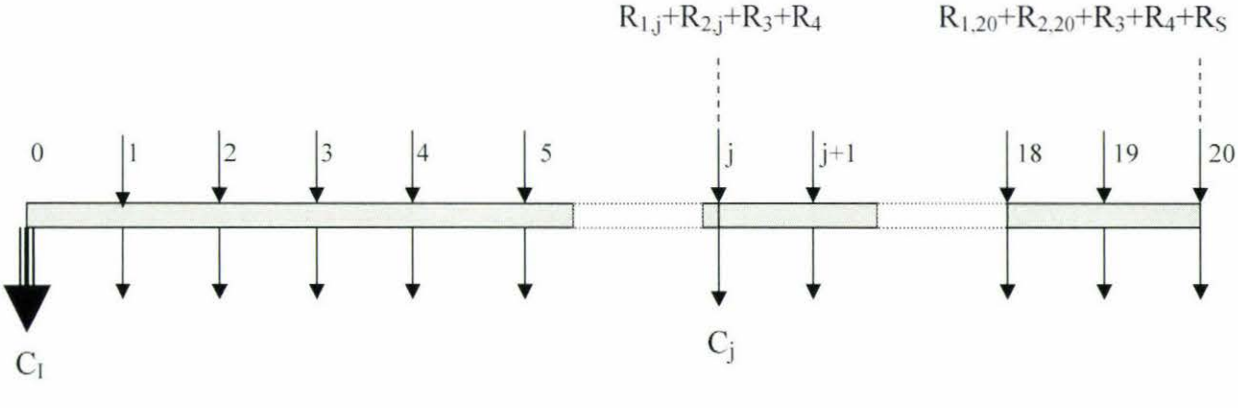

Fig. M.1: The cash inflows and outflows relevant to project investment appraisal

As shown in Fig. M.1, the net cash inflow in the j^th year = $[R_{1,j}+R_{2,j}+R_3+R_4 - C_j]$

Discounting all cash flows to the present value by the discount factor d yield Net present

$$\text{Present value (NPV)} = -C_I + \sum_{j=1}^{j=20} \frac{[R_{1,j}+R_{2,j}+R_3+R_4-C_j]}{(1+d)^j} + \frac{R_S}{(1+d)^{20}} \qquad \text{Eq. M.2}$$

By definition the internal rate of return (IRR) is the discount rate such that NPV = 0 in Eq. M.2

Again by definition, the profitability index (PI) = NPV/Initial investment

$$= \frac{-C_I}{C_I} + \sum_{j=1}^{j=20} \frac{[R_{1,j}+R_{2,j}+R_3+R_4-C_j]}{C_I*(1+d)^j} + \frac{R_S}{C_I*(1+d)^{20}}$$

Hence,

$$PI = -1 + \sum_{j=1}^{j=20} \frac{[R_{1,j}+R_{2,j}+R_3+R_4-C_j]}{C_I*(1+d)^j} + \frac{R_S}{C_I*(1+d)^{20}} \qquad \text{Eq. M.3}$$

The "payback" is the period (in years) which takes the project's net cash inflows to recoup the original investment[2]. Considering annual average net cash inflows, in lieu of net cash inflows of each year, the payback (PB) in years is given by[3];

$$PB * \sum_{j=1}^{j=20} \frac{[R_{1,j}+R_{2,j}+R_3+R_4-C_j]}{20} = C_I$$

$$PB = \frac{[20*C_I]}{\sum_{j=1}^{j=20} [R_{1,j}+R_{2,j}+R_3+R_4-C_j]} \qquad \text{Eq. M.4}$$

---

[2] *"Payback" is also known as the "payback period" in financial management textbooks.*

[3] *Note that on account of escalating cash inflows from one year to the other (due to spot price escalation) the model uses average annual net cash inflows to simplify the calculation of the payback. Strictly speaking, the payback should be calculated adding up each year's net cash inflows (starting from the first year) up until the total is equal to the initial cash investment and then record the payback based on the years taken to meet the above equality.*

Accounting rate of return (ARR) is the ratio of the average annual net cash inflows to the initial (cash) investment.

Hence,

$$ARR = \frac{\sum_{j=1}^{j=20} [R_{1,j}+R_{2,j}+R_3+R_4-C_j]}{20 * C_I} \qquad \text{Eq. M.5}$$

The net preset cost (NPC) is the present value of all costs.

Hence,

$$NPC = C_I + \sum_{j=1}^{j=20} \frac{[C_j]}{(1+d)^j} \qquad \text{Eq. M.6}$$

$$\text{NPC/kWh produced is} = \frac{C_I + \sum_{j=1}^{j=20} \frac{[C_j]}{(1+d)^j}}{20 * \sum_{year} 0.5 * TM3_{m,d,t}} \qquad \text{Eq. M.7}$$

Note that the denominator of Eq. M7 is the amount of energy (in kWh) generated over the lifecycle of the project.

In order to compute the financial indicators shown in Eq. M.2 trough M.6, it is necessary to determine $R_{1,j}$, $R_{2,j}$, R_3 and R_4. The relevant calculations in this regard are shown in sections M.3.1 through M.3.4.

M.3.1 Calculations pertaining to net metering

Under the assumptions made for net metering (see Table 6.4 in Chapter 6), a cash payment for energy inject (i.e. $R_{1,j}$) will only occur if there is surplus generation at the end of the billing year and that the retailer is willing to credit the customer for such excess generation (i.e. $R_S \neq 0$).

As regards the avoided grid energy charge (i.e. $R_{2,j}$), since energy pricing is not based on time of demand side activity, the avoided cost of grid energy shall be the unit energy charge ($/kWh) times the units consumed (kWh) for the whole year, if the total kWh generation exceeds the total kWh energy consumption. If the total kWh generation is less than the total kWh energy consumption, then the avoided cost of grid energy shall be the unit energy charge ($/kWh) times the units generated (kWh) for the whole year. The unit energy charge can assumed to be the annual average variable retail price, provided the user applies a retailer-operating margin that reflects the risk taken by the retailer (section K.1 of Appendix K).

As regards the cash receipts for firm energy/capacity injection during critical peak periods (i.e. R_3), no cash receipts shall be realized unless there is a separate ripple activated meter installed in the grid leg to record the contribution. If a separate meter is available, then readings of such a meter can easily be computed using the $TM1(export)_{m,d,t}$ hypothetical tariff meter reading referred to in Appendix L (see Eq. L.24). In order to calculate the required data the $TM1(export)_{m,d,t}$ data has to be used in conjunction with the dummy variables $a_{m,d,t}$ as a composite variable $[a_{m,d,t} * TM1(export)_{m,d,t}]$. Use of the second dummy variable X_7 (to identify the presence or absence of a separate ripple activated meter) will make sure that $[a_{m,d,t} * X_7 * TM1(export)_{m,d,t}]$ shall provide the energy flows required to compute the critical peak period capacity/energy injection of any net metering situation. It should be noted that the model ignores the difference between apparent power (kVA) and real power (kW).

As regards the avoided critical peak period charges and or maximum demand charges (i.e. R_4), again, separate meters have to be made available to record the relevant readings. Almost invariably, the maximum demand charges are imposed upon larger commercial customers. Moreover a small customer has little control over load regulation and hence the scope for reducing maximum demand. For this reason, the model assumes that there is no maximum demand metering. However, if there is a metering arrangement to meter the load consumed during critical peak periods and the customer is charged based on the critical peak period load as indicated by the said meter, the model can accommodate a critical peak period import-metering scenario similar to the critical peak period export scenario through introduction of the dummy variable X_8. Accordingly $[a_{m,d,t} * X_8 * TM1(import)_{m,d,t}]$ shall provide the energy flows required to compute the critical peak period load of any net metering situation. Again, the model ignores the difference between apparent power and real power.

Using all of the above reasoning mathematically,

$$R_{1,j} = 0 \qquad \text{Eq. M.8a}$$

when $\sum_{year} \text{TM1(import)}_{m,d,t} \geq \sum_{year} \text{TM1(export)}_{m,d,t}$

while

$$R_{1,j} = R_S * \left[\sum_{year} \{C_{RT,m,d,t} * K_j / 17520\}\right] * \left[\sum_{year} \text{TM1(export)}_{m,d,t} - \sum_{year} \text{TM1(import)}_{m,d,t}\right] \qquad \text{Eq. M.8b}$$

when $\sum_{year} \text{TM1(import)}_{m,d,t} < \sum_{year} \text{TM1(export)}_{m,d,t}$

$$R_{2,j} = \left[\sum_{year} \{C_{RT,m,d,t} * K_j / 17520\}\right] * \left[\sum_{year} \text{TM2}_{m,d,t}\right] * 0.5 \qquad \text{Eq. M.9a}$$

when $\sum_{year} \text{TM1(import)}_{m,d,t} < \sum_{year} \text{TM1(export)}_{m,d,t}$

while,

$$R_{2,j} = \left[\sum_{year} \{C_{RT,m,d,t} * K_j / 17520\}\right] * \left[\sum_{year} \text{TM3}_{m,d,t}\right] * 0.5 \qquad \text{Eq. M.9b}$$

when $\sum_{year} \text{TM1(import)}_{m,d,t} > \sum_{year} \text{TM1(export)}_{m,d,t}$

$$R_3 = \frac{\left[C_{FP1} * X_1 * \sum_{year} a_{m,d,t} * X_7 * TM1(export)_{m,d,t}\right]}{0.5 * \sum_{year} a_{m,d,t}} +$$

$$\left[C_{FP2} * X_2 * \sum_{year} a_{m,d,t} * X_7 * TM1(export)_{m,d,t}\right] \qquad \text{Eq. M.10}$$

Note that Eq. M.10 cater to both firm capacity (the first portion) and firm energy (the second portion). However, at any given situation, one of the two dummy variables X_7, X_8 will always be zero because a firm capacity payment and a firm energy payment cannot coexist.[4] The use of dummy variables will allow one equation be written for any net metering scenario.

$$R_4 = \frac{\left[C_{PP} * \sum_{year} a_{m,d,t} * X_8 * TM1(import)_{m,d,t}\right]}{0.5 * \sum_{year} a_{m,d,t}} \qquad \text{Eq. M.11}$$

M.3.2 Calculations pertaining to gross import/gross export metering

The principal difference in the calculations pertaining to the gross import/gross export and the calculations pertaining to net metering was that in the case of the former, in calculating $R_{1,j}$ and $R_{2,j}$, the price of electricity (both spot and retail) was treated as (half hour) time dependant variable.

Although TOU metering was assumed in the gross import/gross export metering, the model does not by default assume that critical peak period metering is in place at the grid leg to measure injection as well as off take, although the incremental cost of implementing a critical peak period meter is small compared to the cost of implementing a half hour TOU meter. As in the case of net metering, the user has to introduce the presence (or otherwise) of the critical peak period meters.

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4. *Counting of both scenarios together will not happen because two separates codes have been used to identify the metering system for injection of generation under critical peak period condition. Code 1 is for a firm energy scenario and code 2 is for a firm capacity scenario (see data block (8) in Fig. 6.10). Since the user cannot enter both 1 and 2 in one cell in the electricity pricing worksheet, inadvertent counting of both scenarios will not occur.*

The code {$TM3_{m,d,t}$ @ "Max ($TM1(import)_{m,d,t}$) $_{June}$}" in Eq. M.14 (page M-13) refers to the TM3 meter load during the particular half hour time interval in June during which TM1(import) meter's half hour load indicates its maximum (i.e. "June maximum demand"). Similar meaning applies to the other two winter months.

Because the load measurements are made on gross import basis, the DG project will cause the maximum demand to go down because of the presence of generation. The model assumes that the maximum demand charges are fixed for winter demand only.

Using all of the above reasoning mathematically,

$$R_{1,j} = \sum_{year} C_{1,m,d,t} * (1+r)^{j-1} * TM1(export)_{m,d,t}$$

Hence, $R_{1,j} = (1+r)^{j-1} * \sum_{year} C_{1,m,d,t} * TM1(export)_{m,d,t}$ Eq. M.12

$$R_{2,j} = \sum_{year} K_j * r_{1,m,d,t} \qquad \text{Eq. M.13}$$

Where, $r_{1,m,d,t}$ is the avoided cost of grid energy at the t^th^ half hour interval of the d^th^ day of the m^th^ month of the first year. As per Eq. M.13, in order to compute $R_{2,j}$ it was sufficient to compute the 17520 nos. $r_{1,m,d,t}$ values of the year.

$$r_{1,m,d,t} = C_{RT,m,d,t} * 0.5 * TM3_{m,d,t} \qquad \text{when, } TM1(export)_{m,d,t} \leq 0 \qquad \text{Eq. M.13a}$$

$$r_{1,m,d,t} = C_{RT,m,d,t} * 0.5 * TM2_{m,d,t} \qquad \text{when, } TM1(export)_{m,d,t} \geq 0 \qquad \text{Eq. M.13b}$$

$$R_3 = \frac{\left[C_{FP1} * X_1 * \sum_{year} a_{m,d,t} * X_7 * TM1(export)_{m,d,t}\right]}{0.5 * \sum_{year} a_{m,d,t}} +$$

$$\left[C_{FP2} * X_2 * \sum_{year} a_{m,d,t} * X_7 * TM1(export)_{m,d,t}\right] +$$

$$X9 * C_{MD} * \Big[\{TM3_{m,d,t} \text{ @ } (Max.TM1\ (import)_{m,d,t})_{June} + \{TM3_{m,d,t} \text{ @ } (Max.TM1(import)_{m,d,t})_{July}\}$$

$$+ \{TM3_{m,d,t} \text{ @ } (Max.TM1(import)_{m,d,t})_{August}\}\Big] \qquad \text{Eq. M.14}$$

$$R_4 = \frac{\left[C_{PP} * \sum_{year} a_{m,d,t} * X_8 * TM1(import)_{m,d,t}\right]}{0.5 * \sum_{year} a_{m,d,t}} \qquad \text{Eq. M.15}$$

M.3.3 Calculations pertaining to separate generation and load metering

Separate generation and load metering is different to other two metering systems in that distributed generation no longer becomes a demand side response to reduce the load drawn from the grid. For this reason under this metering scheme there is no avoided grid energy charges as a result of DG. The Model assumes that the load interface and generation interface are two separate ICPs[5], which is the case in a DG application with a large commercial/industrial customer.

Under this metering scheme, the only way to reduce critical peak period charges or maximum demand charges is to shed all possible loads, upon receipt of the critical peak period signal. The avoided critical peak period charge can be computed by knowing the portion of shedable load, which was defined in section 6.2.2.1 (see the final paragraph).

The model also assumes that any hardware implementation that has been made to reduce the customer load to cause the maximum demand to drop, is not an integral part of the DG system (hence, no avoided maximum demand charge).

Cash receipts for energy inject and cash receipts for firm energy/capacity injection can directly be computed from TM3 data. The model assumes by default that a meter is available to record critical peak period injection. The model also assumes that the avoided cost of grid energy is zero because the load is not influenced by the DG project, other than at critical peak period times (if relevant).

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5. *This assumption is important because if a utility treats the two meters in the generation leg and the load led as two meters of the same ICP, the "separate generation and load metering" becomes just another way of implementing "gross import/gross export metering" or "net metering", as is done by some Australian utilities for small DG customers such as the domestic customers (see Appendix D). This is because the grid leg export reading and the grid leg import reading can always be determined from TM2 and TM3 (Fig. L.1 in Appendix L) readings due to the star connection between the load leg, the generation leg and the grid leg.*

Using all of the aforementioned reasoning mathematically,

$$R_{1,j} = \sum\nolimits_{year} C_{1,m,d,t} * (1+r)^{j-1} * TM3_{m,d,t} \qquad \text{Eq. M.16}$$

$$R_{2,j} = 0 \qquad \text{Eq. M.17}$$

$$R_3 = \frac{\left[C_{FP1} * X_1 * \sum\nolimits_{year} a_{m,d,t} * TM3_{m,d,t}\right]}{0.5 * \sum\nolimits_{year} a_{m,d,t}} + \left[C_{FP2} * X_2 * \sum\nolimits_{year} a_{m,d,t} * X_7 * TM3_{m,d,t}\right] \qquad \text{Eq. M.18}$$

$$R_4 = \frac{\left[C_{PP} * X_6 * \sum\nolimits_{year} a_{m,d,t} * K_{m,d,t} * P^{l}_{L,m,d,t}\right]}{0.5 * \sum\nolimits_{year} a_{m,d,t}} \qquad \text{Eq. M.19}$$

Note that only one equation each was necessary to compute $R_{1,j}$, $R_{2,j}$, R_3 and R_4, for all the metering schemes because of the use of the dummy variables X_3, X_4 and X_5 (e.g. $R_{1,j}$, = $X_3 * R_{1,j} + X_4 * R_{1,j} + X_5 * R_{1,j}$). Because the model uses a separate code to identify the type of metering, there will be no room for errors[4].

M.4 THE INITIAL INVESTMENT OF THE PROJECT AND THE ANNUAL CASH OUTFLOWS

The algorithms used for predicting the initial costs of the subsystems of the DG project as well as the annual costs incurred in operating and maintaining the project are shown in tables M.2 through M.11.

The standard approach adopted in the above algorithms was to forecast the initial cost of the key component of the ten subsystems M.4.1 through M.4.10 and then peg the initial costs of other components of the subsystems as a linear function of the key component.

The standard approach used to forecast the initial cost of the key component of each of the subsystems was to collect publically available cost data and then fit polynomial regression equations with cost as the dependant variable and the subsystem capacity as the independent variable (see row 3 column D in tables M.2 through M.11).

M.4.1 Fuelled generator sets (FGS) - category 1

	Column B	**Column C**	**Column D**
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Standby generator cost including fuel tank, mounting skid	$C_{1,FGS}$	$C_{1,FGS} = N_{1,FGS}\, A*[1876.107 + 1118.44900*(K_{1,FGS}) - 3.94855*(K_{1,FGS})^2 + 0.00550*(K_{1,FGS})^3]$
4	Installation cost *(including cost of switchgear)*		$= N_{1,FGS} * 0.2 * C_{1,FGS}$
5	Rectifier cost		$= N_{1,FGS} * 0.10 * C_{1,FGS}$
6	Other		$= N_{1,FGS} * 0.01 * C_{1,FGS}$
7	***Sub total initial cost***	$C_{1,FGS,\ system}$	= Sum[Row 3 column D : Row 6 column D]
8	Annual fuel cost	$C_{1,fuel}$	$= C_{u,f} * Q_{1,FGS}$
9	Annual O&M cost	$C_{1FGS,O\&M}$	$= 2.5 * C_{1,FGS} * [H_{1,FGS} / 30{,}000]$

Table M.2: The cost structure of the "category 1" fuelled generator set

M.4.2 Fuelled generator set (FGS) - Category 2

	Column B	**Column C**	**Column D**
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Standby generator cost including fuel tank, mounting skid	$C_{2,FGS}$	$C_{2,FGS} = A*[1876.107 + 1118.44900*(K_{1,FGS}) - 3.94855*(K_{1,FGS})^2 + 0.00550*(K_{1,FGS})^3]$
4	Installation cost *(including cost of switchgear)*		$= 0.3 * C_{2,FGS}$

Column B **Column C** **Column D**

Row No.	Items	Abbreviation	Suggested costs (NZ$)
5	Rectifier cost		$= 0$
6	Other		$= 0.15 * C_{2,FGS}$
7	***Sub total initial cost***	$C_{2,FGS,\ system}$	= Sum[Row 3 column D : Row 6 column D]
8	Annual fuel cost	$C_{2,fuel}$	$= C_{u,f} * Q_{2,FGS}$
9	Annual O&M cost	$C_{2FGS,O\&M}$	$= 2.5 * C_{2,FGS} * [H_{2,FGS} / 30{,}000]$

Table M.3: The cost structure of the "category 2" fuelled generator set

M.4.3 Wind turbine generator units (WTG) - Category 1

Column B **Column C** **Column D**

Row No.	Items	Abbreviation	Suggested costs (NZ$)
3	Turbine/tower/controls	$C_{1,WTG}$	IF $K_{1,\ WTG} < 21$ kW, $C_{1,WTG} = N_{1,WTG} * A * [6732.9720 + 6217.0490 * (K_{1,\ WTG}) - 131.2877 * (K_{1,\ WTG})^2 + 1.8083 * (K_{1,\ WTG})^3]$ IF $50 \text{ kW} \geq K_{1,\ WTG} \geq 21$ kW, $C_{1,WTG} = N_{1,WTG} * A * 0.8 * [6732.9720 + 6217.0490 * (K_{1,\ WTG}) - 131.2877 * (K_{1,\ WTG})^2 + 1.8083 * (K_{1,\ WTG})^3]$
4	Spares		$= 0$
5	Transport		$= 0.022 * C_{1,WTG}$
6	Foundation & other civil works		$= 0.05 * C_{1,WTG}$
7	Balance erection work		$= 0$ *(embedded in other costs)*
8	Electrical works		$= 0.14 * C_{1,WTG}$
9	Testing, commissioning & training		$= 0.05 * C_{1,WTG}$
10	Other costs		$= 0.07 * C_{1,WTG}$
11	***Sub total initial cost***	$C_{1,WTG,\ system}$	= Sum [Row 3 column D : Row 10 column D]

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
12	Annual maintenance cost	$C_{1WTG,O\&M}$	IF $K_{1,\,WTG} < 10$ kW, $= 0$ IF $20\text{ kW} > K_{1,\,WTG} \geq 10$ kW, $= 0.05 * C_{1,WTG,\,system}$ IF $50\text{ kW} \geq K_{1,\,WTG} \geq 20$ kW $= 0.025 * C_{1,WTG,\,system}$

Table M.4: The cost structure of the "category 1" wind turbine units

M.4.4 Wind turbine generator unit (WTG) - Category 2

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Turbine/tower/controls	$C_{2,WTG}$	$C_{2,WTG} = [14102.54 + 2120.17*(K_{2,\,WTG}) - 2.940638*(K_{2,\,WTG})^2 + 0.002918*(K_{2,\,WTG})^3]$
4	Spares		$= 0.03 * C_{2,WTG}$
5	Transport		$= 0.03 * C_{2,WTG}$
6	Foundation & other civil works		$= 0.07 * C_{2,WTG}$
7	Balance erection work		$= 0.06 * C_{2,WTG}$
8	Electrical works		$= 0.14 * C_{2,WTG}$
9	Testing, commissioning & training		$= 0.12 * C_{2,WTG}$
10	Other costs		$= 0.01 * C_{2,WTG}$
11	***Sub total initial cost***	$C_{2,WTG,\,system}$	=Sum [Row 3 column D : Row 10 column D]
12	Annual maintenance cost	$C_{2WTG,O\&M}$	$= 0.03 * C_{2,WTG,\,system}$

Table M.5: The cost structure of the "category 2" wind turbine unit

M.4.5 Micro hydro unit (one unit only)

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Turbine, generator & switchgear	C_{MH}	IF $A_{MH} = 1$, $C_{MH} = A*[542.8651 + 3092.1280*(K_{MH}) - 12.1492*(K_{MH})^2 + 0.0627*(K_{MH})^3]$ IF $A_{MH} = 2$, $C_{MH} = A*[556.3460 + 3724.9690*(K_{MH}) - 14.9622*(K_{MH})^2 + 0.0778*(K_{MH})^3]$ IF $A_{MH} = 3$, $C_{MH} = A*2500*(K_{MH})$
4	Civil works & transport		IF $A_{MH} \neq 3$, $= A*1000*(K_{MH})$ IF $A_{MH} = 3$, = 0 *(included in the turbine, generator & switchgear price)*
5	Land consenting & compensation		IF $A_{MH} \neq 3$, = 500 IF $A_{MH} = 3$, = 0 *(included in the turbine, generator & switchgear price)*
6	Election of electro mechanical equipment, testing, commissioning & training		IF $A_{MH} \neq 3$, $= 0.15 * C_{MH}$ IF $A_{MH} = 3$, = 0 *(included in the turbine, generator & switchgear price)*
7	Other costs		IF $A_{MH} \neq 3$, $= 0.10 * C_{MH}$

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
			IF $A_{MH} = 3$, = 0 *(included in the turbine, generator & switchgear price)*
8	***Sub total initial cost***	$C_{MH,\ system}$	= Sum [Row 3 column D : Row 7 column D]
9	Annual maintenance cost	$C_{MH,O\&M}$	IF $A_{MH} \neq 3$, $= 0.05 * C_{MH}$ IF $A_{MH} = 3$, $= 0.03 * C_{MH}$

Table M.6: The cost structure of the micro hydro unit

M.4.6 Photovoltaic (PV) array (one array only)

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Market price of a 50Wp PV module	C_{PV}	$C_{PV} = 450$
4	Price of the PV array		$= A * N_{PV} * C_{PV}$
5	Transport, mounting equipment & installation		$= A * N_{PV} * C_{PV} * 0.2$
6	Other costs including the cost of the MMPT		$= A * N_{PV} * C_{PV} * 0.02$
7	***Sub total initial cost***	$C_{PV,\ system}$	= Sum [Row 4 column D:Row 6 column D]
8	Annual maintenance cost	$C_{PV,O\&M}$	IF $N_{PV} < 20$ =0 IF $N_{PV} \geq 20$ $= 0.005 * N_{PV} * C_{PV}$

Table M7: The cost structure of the PV array

The basis for the percentages given in Table M.8 (page M-21) is author's personal judgement based his experience on design of remote area power systems. If it occurs to the user that the cost of the battery room is excessive, then that may be due to imagining a battery room as a small standard room. There are several safety considerations that have to be complied with in designing a battery room (e.g. fire safety and hence ventilation requirements), equipment such as washing equipment in case of accidental contact of acid (on eyes), quality and type of material used in flooring and the battery rack. All these add up to the costs.

The basis for the percentages given in Table M.9 (page M-21) where the author's personal judgement, but purely arbitrary. There is no documented small scale pumped hydro system even outside New Zealand. Therefore, the author had to have recourse to cost data of various components of (small) hydropower systems, which have many similarities to pumped hydro systems.

M.4.7 Lead acid battery bank (one battery bank only)

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Cost of the battery bank *(battery room excluded)*	C_{BB}	$C_{BB} = A*V_B*N_{BS}*N_{BP}*C_{25}*0.385778$
4	Cost of the battery room		$= 0.7* C_{BB}$
5	Cost of the battery charger		$= 0.3* C_{BB}$
6	Spares		$= 0.1* C_{BB}$
7	Other hardware *(e.g. constant current source)*		$= 0.1* C_{BB}$
8	Cost of installation		$= 0.15* C_{BB}$
9	***Sub total initial cost***	$C_{BB,\ system}$	= Sum [Row 3 column D:Row 8 column D]
10	Annual maintenance cost	$C_{BB,O\&M}$	$= 0.05* C_{BB} + 0.1* C_{BB}$

Table M.8: The cost structure of the lead acid battery bank

M.4.9 Pumped hydro unit

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
3	Pump/turbine, motor/ generator and piping	C_{PH}	$C_{PH} = A* K_{PH} *1500$
4	Cost of installation		$= 0.3* C_{PH}$
5	Total cost of civil works and contingencies		$= 1.8* C_{PH}$
6	***Sub total initial cost***	$C_{PH,\ system}$	= Sum [Row 3 column D : Row 5 column D]
7	Annual O&M cost	$C_{PH,O\&M}$	$= 0.05* C_{PH}$

Table M.9: The cost structure of the pumped hydro unit (one unit only)

M.4.9 Grid interactive inverter

Row No.	Items Column B	Abbreviation Column C	Suggested costs (NZ$) Column D
3	The inverter unit and the control panel	C_{INV}	IF $K_{INV} < 10$ $C_{INV} = A * [1107.7450 + 1819.726*(K_{INV}) + 14.7123*(K_{INV})^2]$ IF $K_{INV} \geq 10$ $C_{INV} = A * 1200.000*(K_{INV})$
4	Cost of installation		= 0 (embedded in wiring and fixing of the control panel)
5	Wiring and fixing of the control panel		$= 0.12* C_{INV}$
6	***Sub total initial cost***	$C_{INV,\ system}$	= Sum [Row 3 column D:Row 5 column D]
7	Annual O&M cost	$C_{INV,O\&M}$	$= 0.01* C_{INV}$

Table M.10: the cost structure of the grid interactive inverter

M.4.10 The metering system

Row No.	Items Column B	Abbreviation Column C	Suggested costs (NZ$) Column D
3	The meters	C_{MET}	IF $X_3 = 1$ and no critical peak period metering (PPM) $C_{MET} = 100$, with PPM $C_{MET} = 200$ IF $X_4 = 1$ and no critical peak period metering (PPM) $C_{MET} = 350$, with PPM $C_{MET} = 500$ IF $X_5 = 1$ and no critical peak period metering (PPM) $C_{MET} = 350$, with PPM $C_{MET} = 500$

	Column B	Column C	Column D
Row No.	**Items**	**Abbreviation**	**Suggested costs (NZ$)**
4	Labour cost of installation		IF X_3 =1 and no critical peak period metering (PPM) = 100, with PPM = 200 IF X_4 =1 or X_5 =1 and no critical peak period metering (PPM) = 200, with PPM = 300
5	Material cost of installation (excl. meter): Meter box, cables and other accessories		IF X_5 =1 The following is the minimum suggested: =[400+ {Installed DG capacity (kVA)}* 20] The following is the maximum suggested: =[400+ {Installed DG capacity (kVA)}* 60] (this is the maximum suggested) IF X_4 =1 The following is a typical cost suggested: =[400+ {Installed DG capacity (kVA)}* 20] IF X_3 =1 = 100
6	***Sub total initial cost***	$C_{MET,\ system}$	= Sum [Row 3 column D : Row 5 column D]
7	Annual charges for connection/grid injection	C_{Inj}	IF X_5 =1 = [Installed DG capacity (kVA)]* 24 IF X_4 =1 = [Installed DG capacity (kVA)]* 12

Column B **Column C** **Column D**

Row No.	Items	Abbreviation	Suggested costs (NZ$)
			IF X_3 =1 = 0
8	Annual O&M cost	$C_{MET,O\&M}$	= 0

Table M.11: The cost structure of the metering system

The initial cost of the total DG system is the summation of the initial costs of the individual systems listed in Table M.2 through M.10.

The initial cost of the project is the sum of the initial costs associated with the individual subsystems.

Accordingly,

$$C_I = C_{1,FGS,system} + C_{2,FGS,system} + C_{1,WTG,system} + C_{2,WTG,system} + C_{MH,system} + C_{PV,system} + C_{BB,system} + C_{PH,system} + C_{INV,system} + C_{MET,system} \qquad \text{Eq. M.20}$$

The costs incurred (treated as cash outflows by the model) each year, as a result of operating the project, is the sum of annual costs of the individual subsystems. Additionally, the cost incurred on energy purchases for energy storage devices (i.e. $C_{S,j}$) have also to be added as it is an opportunity cost.

Accordingly,

$$C_j = C_{S,j} + C_{1,fuel} + C_{1,FGS,O\&M} + C_{2,fuel} + C_{2,FGS,O\&M} + C_{1,WTG,O\&M} + C_{2,WTG,O\&M} + C_{MH,O\&M} + C_{PV,O\&M} + C_{BB,O\&M} + C_{PH,O\&M} + C_{INV,O\&M} + C_{MET,O\&M} + C_{Inj} \qquad \text{Eq. M.21}$$

$C_{S,j}$ could be calculated as follows:

$$C_{S,j} = [P_{5a,m,d,t} + P_{10a,m,d,t}] * [(1+R)*(1+r)^{j-1} * C_{1,m,d,t} + K_{LC} * C_{LC,m,d,t}] * [1/0.9] \qquad \text{Eq. M.22}$$

The first square parenthesis of Eq. M.15 is the load drawn by the energy storage devices. The second square parenthesis is the variable retail price of the j^{th} year (see Eq. K.5 in Appendix K) while the third square parenthesis is an adjustment to the variable retail charge to take in to account an assumed 10% fixed charge.

M.5 LINES COMPANY FOREGONE REVENUE CALCULATIONS

A lines company will forego revenue due to net metering and gross import/gross export metering because these metering schemes do offset part of the customer energy consumption, which contribute towards lines company revenue stream.

In cases where "critical peak period demand pricing (CPPDP)" exist, in cases where the load and generation are separately metered (i.e. $X_5 = 0$), the customer can reduce the load by deliberate personal intervention by shedding the load during critical peak periods, thereby reducing critical peak period demand. In cases where the customer is metered on the grid leg only (i.e. gross import/export or net metering), dispatching capacity (or energy) to the grid during critical peak periods, causes the same effect. It can be argued that these demand side responses (i.e. load shedding by the customer or dispatching DG) actually help the lines company and should not be included as a loss. The model treats reduction of the critical peak period load as a loss to a lines company (in cases where meters are available to record the critical peak period consumption) because it causes the lines company to forego the opportunity of charging more, based on critical peak period tariffs ($/kW or $/kVA).

In cases where "maximum demand pricing (MDP)" exist, this too causes the lines company to forego revenue (possibly to a lesser extent) to the extent that demand side responses resulting from distributed generation or load shedding (initiated by the customer) can cause maximum demand to drop.

Since CPPDP and MDP are both capacity based charges and the model assumes that only one would exist at any given situation, only one will be calculated for a given situation, through the use of the dummy variables defined on Table M.1.

Finally, the lines company foregone revenue will also depend on whether a DG customer is charged for interconnection[6] or not.

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[6] *Charges for interconnection may also be called charges for grid injection by some utilities.*

Let,

α_1 = annual foregone revenue due to lowered energy delivery

α_2 = annual foregone revenue due to CPPDP policy or due to MDP policy

α_3 = annual charges levied upon DG customers for interconnection annually

The annual foregone revenue for a lines company can be expressed as follows.

Total annual foregone revenue = [annual foregone revenue due to lowered energy delivery] + [annual foregone revenue due to CPPDP policy] + [annual foregone revenue due to MDP policy] – [annual charges levied on DG customers for interconnection annually]

Total annual foregone revenue = $\alpha_1 + \alpha_2 - \alpha_3$ Eq. M23

Now α_1 and α_2 required for the equation M.23 are determined as follows.

(a) Computation of α_1

if $X_5 = 1$ (i.e. separate generation and load metering), then $\alpha_1 = 0$ Eq. M.24a

if $X_5 \neq 1$ and $X_3 = 1$ (i.e. net metering);

$$\text{then } \alpha_1 = \left[\sum\nolimits_{year} \{L_{,m,d,t}/17520\}\right] * \left[\sum\nolimits_{year} TM2_{m,d,t}\right] * 0.5 \qquad \text{Eq. M.24b}$$

$$\text{when} \quad \sum\nolimits_{year} TM1(import)_{m,d,t} < \sum\nolimits_{year} TM1(export)_{m,d,t}$$

while,

$$\alpha_1 = \left[\sum\nolimits_{year} \{L_{,m,d,t}/17520\}\right] * \left[\sum\nolimits_{year} TM3_{m,d,t}\right] * 0.5 \qquad \text{Eq. M.24c}$$

$$\text{when} \quad \sum\nolimits_{year} TM1(import)_{m,d,t} > \sum\nolimits_{year} TM1(export)_{m,d,t}$$

where $L_{,m,d,t}$ is the time dependant energy based line charge in \$/kWh).

if $X_5 \neq 1$ and $X_4 = 1$ (i.e. gross import/gross export metering);

then $\alpha_2 = \sum_{year} x_{,m,d,t}$ Eq. M25

where, $x_{,m,d,t}$ is the avoided cost of (energy based) line charge at the t^th^ half hour interval of the d^th^ day of the m^th^ month of any year.

$x_{,m,d,t} = L_{,m,d,t} * 0.5 * TM3_{m,d,t}$ when, $TM1(export)_{m,d,t} \leq 0$ Eq. M.25a

$x_{,m,d,t} = L_{,m,d,t} * 0.5 * TM2_{,m,d,t}$ when, $TM1(export)_{m,d,t} \geq 0$ Eq. M.25b

(a) Computation of α_2

Since annual foregone revenue due to CPPDP policy or due to MDP policy (i.e. α_2)is the same as customer's avoided critical peak period charges and/or the maximum demand (MD) charges each year (calculated through Eq. M.11, M.15 and M.19 depending on the relevant metering scheme). Stated mathematically,

$\alpha_2 = R_4$ Eq. M26

M.6 OTHER MISCELLANEOUS CALCULATIONS

M.6.1 Annual fuel consumption of fuelled generator sets

As the thermal efficiency and the specific fuel consumption (i.e. volume of fuel consumed to produce 1 kWh of energy) of fuelled generator sets (FGSs) improve depending on the loading level as well as the capacity, it was necessary to device an equation encompassing both the capacity of the FGS and the loading level. Accordingly data on fuel consumption rates of different FGSs of different prime ratings (kW) for 25%, 50%, 75% and 100% loading levels were collected from manufacturer published data.

The following fuel curves were derived from the regression analysis. The approach used was to find a regression equation with the specific fuel consumption as the dependant variable and normalised load (i.e. the load as a fraction of the prime capacity of the FGS) and the

Time needed to refuel the fuel tank depending on the frequency of use is embodied in the operation and maintenance (O&M) costs of the diesel engines. Please refer to row 9 in Table M.2 (page M-16) and note that the annual O&M cost is linearly proportional to operating hours ($H_{1,FGS}$) of the unit.

FGS capacity as the independent variable. Analysis of data indicated that for gen sets with capacities greater than 180 kW, the capacity is no more a factor that affects the specific fuel consumption, for a given % loading level of the FGS.

The ordinary lease square (OLS) polynomial regression equations M.27a and M.27b as shown below were fitted using capacity and fuel consumption data (at different loading levels) by different manufacturers.

IF 'X' is the loading level of the FGS as a fraction of its prime capacity C, then the specific fuel consumption 'S' of the FGS is given by:

$$S = 0.8442 - 1.5970X + 1.9346X^2 - 0.7878X^3 - 0.00139C, \quad \text{if, } C \leq 180 \text{ kW} \qquad \text{Eq. M.27a}$$

$$S = 0.55 - 1.1067X + 1.36X^2 - 0.5333X^3 \quad \text{if, } C > 180 \text{ kW} \qquad \text{Eq. M.27b}$$

For the computer model, X shall always be unity since it was assumed that the FGS is operating on its prime capacity at all times. Hence, S was treated as a constant, given the capacity of the FGS.

Using the abbreviations in Table M.1 and the abbreviations S for specific fuel consumption and C for prime capacity;

$$\text{The operating hours of the FGS} = 0.5 * \sum_{year} a_{m,d,t} \qquad \text{Eq. M.28}$$

$$\text{Total fuel consumption (in lit)} = S * C * 0.5 * \sum_{year} a_{m,d,t}$$

Assuming the lower heat value (LHV) of diesel as 42.7 MJ/kg, and the density as 0.85 kg/l, for diesel generator sets;

$$\text{The annual average thermal efficiency (LHV)} = \frac{3600 * \text{Annual kWh generated} * 100}{\text{Total fuel consumption} * 0.87 * 42{,}700} \qquad \text{Eq. M.29}$$

APPENDIX N

Totara Valley/Kumeroa load data estimation

This appendix provides necessary load parameter calculations in order to provide the required data for the *load worksheet* of the computer program. Essentially two tasks are performed in this appendix.

The first task (section N.1) is to generate the monthly half hour mean load and the standard deviation of a single (representative) farm for the six months for which data was not obtained, i.e. January, February, September, October, November and December (also see section 6.3.1).

The second task (sections N.2 and N3) is to estimate half hourly monthly mean load and the standard deviation in respect of Totara Valley Zones B and C.

N.1 Estimation of monthly half hour mean load and the standard deviation for a single (representative) farm for the months; January, February, September, October, November and December based on the other 6 months for which data was obtained (section 5.8.1 and section 6.3.1):

In respect of the three spring months September through November it was assumed that the following one to one correspondence exist with the three autumn months (for which data was available).

- September half hour mean values and standard deviations are identical to May half hour mean values and standard deviations.
- October half hour mean values and standard deviations are identical to April half hour mean values and standard deviations.
- November half hour mean values and standard deviations are identical to March half hour mean values and standard deviations.

In respect of the three summer months, the following 4-step calculation procedure was executed (Table N.1).

Step 1: Calculation of the winter half hour mean load and the coefficient of variation, based on May-Aug data. The calculation was based on a simple averaging procedure.

It is agreed that use of winter basis for summer load in not the way to determine summer loads (page N-2) of the community if rescaling has been done arbitrarily. However, author has not blindly rescaled winter loads to derive summer loads. The rescaling was done to conform to seasonal load trends derived from previous load research data. Fig. 7.14 was the basis for derivation of summer loads from winter loads. The rescaling also took into account the diversity of load behaviour of each month in a given season (paragraph 2 in page 148).

There is no other known better way to forecast summer load data with the limited historical data that was available to the author.

Step 2: Tabulation of Summer/Winter loading ratios for each half hour based Fig. 7.15 (Chapter 7).

Step 3: Calculation of the summer half hour mean load by rescaling the winter load (Step 1) based on data tabulated in Step 2 above.

Step 4: The February and December half hour mean loads were calculated assuming that there is one to one correspondence between these two months and that the corresponding values could be obtained by rescaling the summer profile by a factor of 0.95. January profile was obtained rescaling the summer values by a factor of 1.1.

As regards the coefficients of variation (i.e. standard deviation ÷ mean), it was assumed that the summer values were identical to winter average value (i.e. column (C) of Table N.1).

	SETP 1		**STEP 2**	**STEP 3 =** **Col. (B)*Col (D)**	**STEP 4** **Feb .& Dec. = 0.95 Summer** **Jan = 1.1 Summer**	
(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)**	**(G)**
Period	Winter Mean Load (kW)	Average COV	Loading ratio (Summer/Winter)	Calculated Summer Mean Load (kW)	Calculated February & December Mean Load (kW)	Calculated January Mean Load (kW)
1	2.13	0.39	0.79	1.68	1.60	1.85
2	1.74	0.42	0.77	1.34	1.27	1.47
3	1.58	0.43	0.80	1.26	1.20	1.39
4	1.51	0.41	0.84	1.27	1.20	1.40
5	1.47	0.39	0.86	1.26	1.20	1.39
6	1.57	0.40	0.81	1.27	1.21	1.40
7	1.54	0.54	0.84	1.29	1.23	1.42
8	1.50	0.47	0.87	1.31	1.24	1.44
9	1.49	0.40	0.82	1.22	1.16	1.34
10	1.47	0.38	0.80	1.18	1.12	1.29
11	1.91	0.33	0.82	1.57	1.49	1.72
12	2.04	0.39	0.93	1.90	1.80	2.09
13	1.83	0.42	1.04	1.90	1.81	2.09
14	2.09	0.53	1.04	2.17	2.06	2.39
15	2.31	0.48	0.96	2.22	2.11	2.44

	SETP 1		STEP 2	STEP 3 = Col. (B)*Col (D)	STEP 5 Feb .& Dec. = 0.95 Summer Jan = 1.1 Summer	
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Period	Winter Mean Load (kW)	Average COV	Loading ratio (Summer/Winter)	Calculated Summer Mean Load (kW)	Calculated February & December Mean Load (kW)	Calculated January Mean Load (kW)
16	2.73	0.47	0.87	2.38	2.26	2.61
17	2.89	0.40	0.96	2.77	2.64	3.05
18	2.88	0.46	1.00	2.88	2.74	3.17
19	2.88	0.45	0.94	2.71	2.57	2.98
20	2.54	0.45	1.00	2.54	2.41	2.79
21	2.43	0.50	1.01	2.45	2.33	2.70
22	2.52	0.52	1.03	2.60	2.47	2.86
23	2.92	0.43	0.97	2.83	2.69	3.12
24	3.21	0.47	0.97	3.11	2.96	3.43
25	2.98	0.49	0.99	2.95	2.80	3.25
26	2.50	0.46	0.98	2.45	2.33	2.70
27	2.26	0.47	0.98	2.21	2.10	2.44
28	2.23	0.50	0.96	2.14	2.03	2.35
29	2.25	0.46	0.93	2.09	1.99	2.30
30	2.32	0.45	0.98	2.27	2.16	2.50
31	2.24	0.46	0.86	1.93	1.83	2.12
32	2.22	0.44	0.88	1.95	1.86	2.15
33	2.27	0.48	1.00	2.27	2.16	2.50
34	2.59	0.45	1.06	2.75	2.61	3.02
35	3.46	0.45	1.00	3.46	3.29	3.81
36	4.66	0.37	1.16	5.41	5.14	5.95
37	4.36	0.39	1.28	5.58	5.30	6.14
38	4.09	0.38	1.57	6.42	6.10	7.06
39	4.25	0.37	1.61	6.84	6.50	7.53
40	3.87	0.37	1.53	5.92	5.63	6.51
41	3.80	0.35	1.60	6.08	5.78	6.69
42	3.61	0.34	1.54	5.56	5.28	6.12
43	3.19	0.35	1.33	4.24	4.03	4.67
44	3.02	0.39	1.14	3.44	3.27	3.79
45	2.77	0.41	0.93	2.58	2.45	2.83
46	2.38	0.45	0.79	1.88	1.79	2.07
47	2.26	0.40	0.71	1.60	1.52	1.77
48	2.67	0.39	0.73	1.95	1.85	2.14

Table N.1: Calculation of half hourly mean loads for the three summer months

In order to derive accurate data for a sampling frame (i.e. Zone B or Zone C) from Zone A, it was assumed that Zone B and Zone C community loads in any given time interval are equal to 10 times and 20 times that of Zone A respectively. This is not an ideal load estimation methodology for a large community as it inherits the suggestion that neighbouring communities are homogeneous as far as the load use is concerned.

The theoretical framework for estimating real time community load (i.e. load profiling) was covered in section 4.4. All the aspects of community load profiling (for Zones B & C) could not be applied due to want of additional information such as types and classes of customers in the community, their annual energy consumption, load profiles of each class of customers etc. Obtaining all of this information in the form of scientific data was deemed impractical within the time frame and resources allocated for the research.

Hence, mean load of the larger community (i.e. Zone B or Zone C) was estimated assuming these to be linear functions of a representative beef and sheep farm of Zone A (please see the black graphs in Fig. 7.9) that was monitored. The factors 10 and 20 applied for Zones B and C respectively was a judgement based on ICP data from ScanPower (Table 7.1 on page 161), site visits and responses received from farmers in Zone A about the nature and type of loads in their neighbouring zones (paragraph 2 of page 103).

As an illustration let us compare Zone C with Zone A. In Zone C there are 89 ICPs altogether (Table 7.1) whereas in Zone A there are only 11 ICPs for the 3 farms (so 3.67 ICPs per farm). So if one were to interpolate the load purely on ICP data, Zone C load should be 24.25 times the load of a representative farm (being 89/3.67). This was adjusted to 20 taking into consideration the types and nature of loads in Zone C. For instance the dairy shed (C1 type connection) consumes much more energy than a C1 type connection in Zone A (excluding the off season) but on the other hand C.1.2 type connections in Zone C just add to numbers without consuming much energy (it was observed that most of these connections were dedicated connections for electric fences).

N.2 Load estimation of Zone B

Based on data on Table 7.1 (Chapter 7) and site visits, it was decided that the average load profile of whole of Zone B could be computed by rescaling the average load profile of the farms in Zone A by multiplying the same by a factor of 10. The assumption was primarily based on the number of respective types of ICPs as a factor of the corresponding number of ICPs in Zone A. Accordingly, for the application of the computer model, the half-hourly mean loads for each month were computed by multiplying the single farmer values derived from site measurements by a factor of 10. The coefficients of variation for each half hour for Zone B were calculated by single farm coefficients of variation divided by the square root of 10 (Eq. 4.7).

N.3 Load estimation of Zone C

The computation of mean and the coefficients of variations for Zone C were obtained by multiplying the single farm values by a factor of 20 based on the types of ICPs as was done for Zone B. The coefficients of variation were calculated by dividing the single farmer values by the square root of 20 (Eq. 4.7 of Chapter 4).

There is a dairy shed, a school and a community centre in Kemeroa whose load profiles would be different to the representative farm load profile derived for Zone A. However, because load data of Zone B and C are critical only if gross import gross export metering is implemented and there is only a theoretical possibility of it being implemented to Zone C, and because resources are needed to obtain the additional data, no adjustments were made to the means and standard deviations derived based on single farm data.

Note that for separate generation and load metering, the DG does not reduce the load drawn from the system to the community. Out of the two metering schemes, the separate generation and load metering scheme is the most likely scheme that would be allowed as billing a DG customer based on a single meter in the grid leg only is generally reserved for customers with moderate DG, where DG is actually treated as small negative load, as described in Appendix D (section D.2.1).

APPENDIX O

Graphical presentation of the calculations performed in the load work sheet

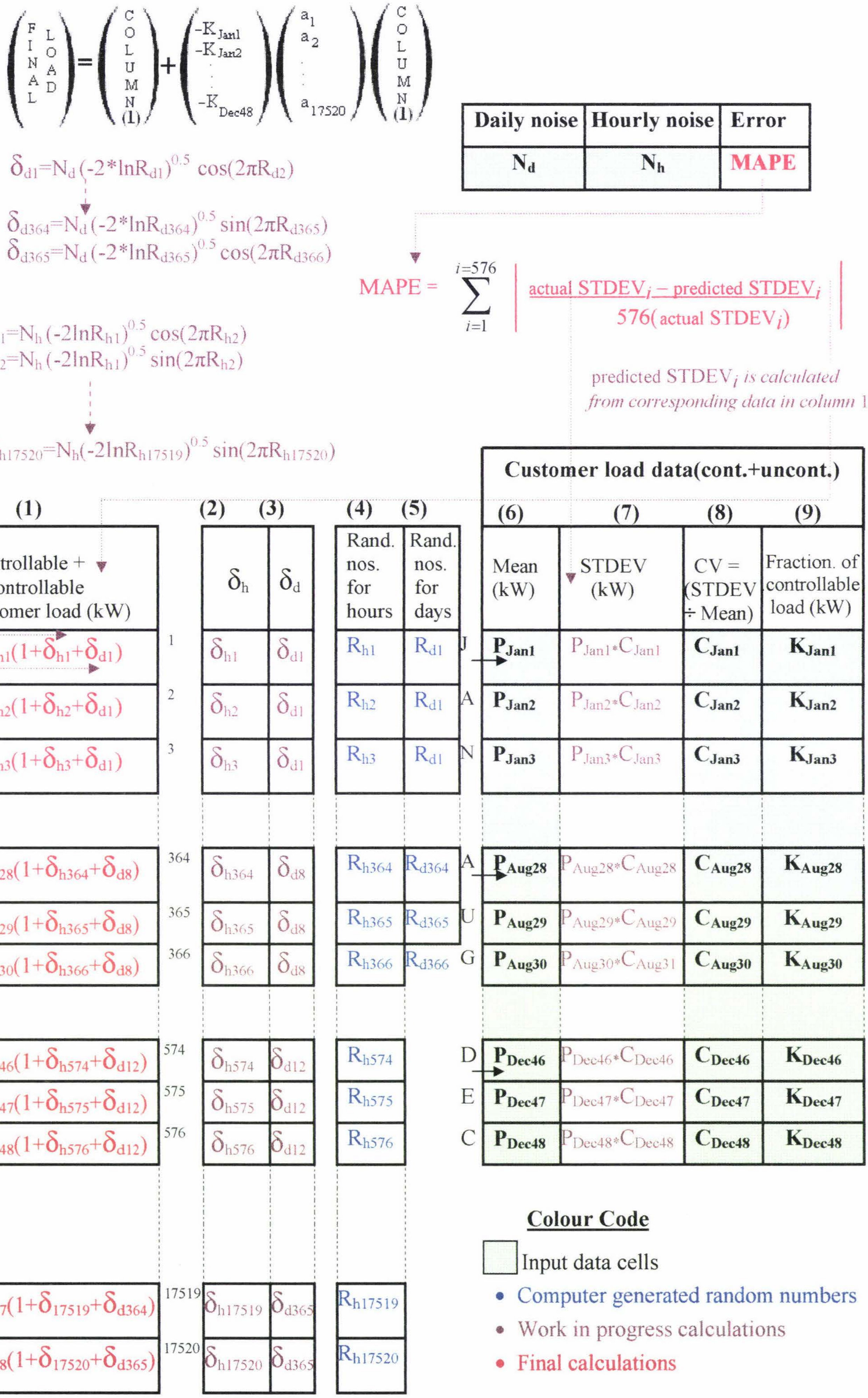
In order to understand Table O.1 in Appendix – O, please refer to the flow chart (Fig. 6.6) on page 123.

The $\overline{P}_{m,t}$ values in Fig. 6.6 are the values in column (6) of Table O.1.

Thus, the suffixes (e.g. $_{Jan1, Jan2, Jan3}$ etc.) in columns (6) through (9) of Table O.1 actually refer to half hour time intervals of a month and not the days of the month. For example, P_{Jan3} is the mean load during the 3rd half hour time interval (out of 48 half hour time intervals of the day) of the month of January and P_{Dec48} is the mean load during the 48th half hour time interval of the month of December. On the same token C_{Jan3} (see column (9)) is the coefficient of variation of the load during the 3rd half hour time interval of the month of January and C_{Dec48} is the coefficient of variation of the load during the 48th half hour time interval of the month of December.

Note how the load during corresponding to a half hour time interval of a given month of a given day (see column (1)) is generated from the mean load (see column (6)) and the two unique random disturbance parameters δ_h and δ_d (see columns (2) and (3) respectively). Although δ_h and δd values are fixed for a given half hour time interval of a given day, these values are actually contingent on the "daily noise" (i.e. N_d) and the "hourly noise" (N_h) values inputted by the user.

Form the half hour loads synthesised, the model calculates standard deviations of the load for each half hour time interval for the 12 months of the year (hence 576 sets of values) with a view to determine the error (MAPE) between the aforesaid calculated values (also called predicted values) and the actual values determined from load research data (see column (7)). If the error is excessive, the "daily noise" and the "hourly noise" are readjusted up until the target MAPE value is reached. This iterative process is not depicted in Table O.1 however.



$$\begin{pmatrix} \text{F}\ \ \text{L} \\ \text{I}\ \ \text{O} \\ \text{N}\ \ \text{A} \\ \text{A}\ \ \text{D} \\ \text{L} \end{pmatrix} = \begin{pmatrix} \text{C} \\ \text{O} \\ \text{L} \\ \text{U} \\ \text{M} \\ \text{N} \\ (1) \end{pmatrix} + \begin{pmatrix} -K_{Jan1} \\ -K_{Jan2} \\ \vdots \\ -K_{Dec48} \end{pmatrix} \begin{pmatrix} a_1 \\ a_2 \\ \vdots \\ a_{17520} \end{pmatrix} \begin{pmatrix} \text{C} \\ \text{O} \\ \text{L} \\ \text{U} \\ \text{M} \\ \text{N} \\ (1) \end{pmatrix}$$

Daily noise	Hourly noise	Error
N_d	N_h	MAPE

$$\delta_{d1} = N_d(-2*\ln R_{d1})^{0.5}\cos(2\pi R_{d2})$$

$$\delta_{d364} = N_d(-2*\ln R_{d364})^{0.5}\sin(2\pi R_{d365})$$

$$\delta_{d365} = N_d(-2*\ln R_{d365})^{0.5}\cos(2\pi R_{d366})$$

$$\text{MAPE} = \sum_{i=1}^{i=576}\left|\frac{\text{actual STDEV}_i - \text{predicted STDEV}_i}{576(\text{actual STDEV}_i)}\right|$$

predicted STDEV_i *is calculated from corresponding data in column 1*

$$\delta_{h1} = N_h(-2\ln R_{h1})^{0.5}\cos(2\pi R_{h2})$$

$$\delta_{h2} = N_h(-2\ln R_{h1})^{0.5}\sin(2\pi R_{h2})$$

$$\delta_{h17520} = N_h(-2\ln R_{h17519})^{0.5}\sin(2\pi R_{h17520})$$

(1)		(2)	(3)	(4)	(5)		Customer load data(cont.+uncont.) (6)	(7)	(8)	(9)
Controllable + uncontrollable customer load (kW)		δ_h	δ_d	Rand. nos. for hours	Rand. nos. for days		Mean (kW)	STDEV (kW)	CV = (STDEV ÷ Mean)	Fraction. of controllable load (kW)
$P_{Jan1}(1+\delta_{h1}+\delta_{d1})$	1	δ_{h1}	δ_{d1}	R_{h1}	R_{d1}	J	P_{Jan1}	$P_{Jan1}*C_{Jan1}$	C_{Jan1}	K_{Jan1}
$P_{Jan2}(1+\delta_{h2}+\delta_{d1})$	2	δ_{h2}	δ_{d1}	R_{h2}	R_{d1}	A	P_{Jan2}	$P_{Jan2}*C_{Jan2}$	C_{Jan2}	K_{Jan2}
$P_{Jan3}(1+\delta_{h3}+\delta_{d1})$	3	δ_{h3}	δ_{d1}	R_{h3}	R_{d1}	N	P_{Jan3}	$P_{Jan3}*C_{Jan3}$	C_{Jan3}	K_{Jan3}
$P_{Jan28}(1+\delta_{h364}+\delta_{d8})$	364	δ_{h364}	δ_{d8}	R_{h364}	R_{d364}	A	P_{Aug28}	$P_{Aug28}*C_{Aug28}$	C_{Aug28}	K_{Aug28}
$P_{Jan29}(1+\delta_{h365}+\delta_{d8})$	365	δ_{h365}	δ_{d8}	R_{h365}	R_{d365}	U	P_{Aug29}	$P_{Aug29}*C_{Aug29}$	C_{Aug29}	K_{Aug29}
$P_{Jan30}(1+\delta_{h366}+\delta_{d8})$	366	δ_{h366}	δ_{d8}	R_{h366}	R_{d366}	G	P_{Aug30}	$P_{Aug30}*C_{Aug31}$	C_{Aug30}	K_{Aug30}
$P_{Jan46}(1+\delta_{h574}+\delta_{d12})$	574	δ_{h574}	δ_{d12}	R_{h574}		D	P_{Dec46}	$P_{Dec46}*C_{Dec46}$	C_{Dec46}	K_{Dec46}
$P_{Jan47}(1+\delta_{h575}+\delta_{d12})$	575	δ_{h575}	δ_{d12}	R_{h575}		E	P_{Dec47}	$P_{Dec47}*C_{Dec47}$	C_{Dec47}	K_{Dec47}
$P_{Jan48}(1+\delta_{h576}+\delta_{d12})$	576	δ_{h576}	δ_{d12}	R_{h576}		C	P_{Dec48}	$P_{Dec48}*C_{Dec48}$	C_{Dec48}	K_{Dec48}
$P_{Dec47}(1+\delta_{17519}+\delta_{d364})$	17519	δ_{h17519}	δ_{d365}	R_{h17519}						
$P_{Dec48}(1+\delta_{17520}+\delta_{d365})$	17520	δ_{h17520}	δ_{d365}	R_{h17520}						

Colour Code

🟩 Input data cells

- Computer generated random numbers
- Work in progress calculations
- Final calculations

Table O.1: The graphical presentation of the algorithm for synthesis of customer load data

APPENDIX P

Specific assumptions made on Totara Valley DG simulations

P.1 LINES COMPANY RELATED DATA

P.1.1 Line charges

P.1.1.1 Variable line charges (LV metering with individual farm based applications):

Block No.	Start Period (half hour time interval)	Variable line charge (c/kWh)	
1	7	4	
2	15	6	
3	23	6	
4	31	6	
5	39	6	
6	47	4	
Fixed Charge as a % of total bill			*10.0%*

The above variable line charge figures were multiplied by the loss factor which is 1.08814 (i.e. a loss ratio of 8.1%), as stipulated by ScanPower (Appendix F).

P.1.1.2 Variable line charges for Totara Valley Zones B&C involving 11 kV gross import/gross export metering:

Block No.	Start Period (half hour time interval)	Variable line charge (c/kWh)	
1	7	1.34	
2	15	3.84	
3	23	3.84	
4	31	3.84	
5	39	3.84	
6	47	1.34	
Fixed Charge as a % of total bill			*10.0%*

The above variable line charge figures were multiplied by the loss factor which is 1.07852 (i.e. a loss ratio of 7.28%), as stipulated by ScanPower (Appendix F).

P.1.1.3 The maximum demand charge (applicable to Zones B&C under 11 kV gross import/gross export metering only) = $ 4.00/kVA (effect of power factor ignored).

P.1.2 Annual interconnection charges for distributed generation (DG) = None.

P.1.3 Payments to DG owners for provision of firm capacity provided during critical peak periods (hypothetical) = $ 120.00/average kW/year

P.1.4 The distribution network constraints on DG uptake = None. (This effectively assumes that the distribution network is an infinite sink and does not cause any power quality issue such as voltage flicker).

In addition to above, in the event of demand side responses such as diesel generation during critical peak periods, it was assumed that a lines company does not receive any direct benefit (in the longer run) from Transpower by reducing the peak loads at the GXP. This is because Transpower can (and probably will have to) increase its connection charges to recover returns on its HVAC assets (section 2.5.3.2). Therefore, it was assumed that the sole purpose of dispatchable generation from a lines company perspective is capacity support of their own network.

P.2 ENERGY RETAILER RELATED DATA

P.2.1 Energy prices: based on Haywards GXP year 2002, spot prices.

P.2.2 Annual spot price escalation rate = 3.5%

P.2.3 Retailer's margin = 20% on spot prices for gross import/gross export metering.

= 30% on spot prices for net metering.

= 0% on spot prices for separate generation metering

P.2.4 Annual average retail price rescale factor for year end settlements for net metering = 0.4

P.3 DATA RELATED TO THE DEMAND SIDE STRATEGIES

P.3.1 <u>Operation of the standby diesel generator during farm peak load hours to offset high load and energy prices (applicable to Zone A only)</u>:

	Start Period (half hour time interval)	**End Period** (half hour time interval)
Summer	39	41
Autumn	37	39
Winter	33	35
Spring	37	39

P.3.2 Operation of the standby diesel generator as a response to critical peak period pricing (hypothetical) faced by the lines company:

	Start Period (half hour time interval)	**End Period** (half hour time interval)
Summer	*None*	*None*
Autumn	*None*	*None*
Winter	36	37
Spring	*None*	*None*

Note that the actual calendar days are determined by the computer through a random process, based on the total number of peak period days per season.

P.3.3 Cost of diesel = 60 c/l

P.4 ASSUMPTIONS MADE IN RELATION TO DISTRIBUTED GENERATION PROJECT INVESTMENT

- The investor has no restriction on capital acquisition.
- The investor's weighted average cost (WACC) of capital is 5%
- The risk premium added to WACC is zero *(the risk is discussed subsequently)*.
- All initial costs on project components are based on the figures generated by the model's cost prediction algorithm (section M.4, Appendix M).
- In cases where state provides subsidies in the form of low interest loans for renewable energy projects, the interest rate charged for the loans is zero. Moreover, the subsidies are available only for the renewable energy DG units (and their associated components) in respect of hybrid DG systems involving renewables and non-renewables.
- The salvage value of the project at the end of the 20-year project life cycle is zero.

P.5 RENEWABLE RESOURCE DATA

P.5.1 Wind data: As per default time series data referred to in section 6.2.3 in Chapter 6.

P.5.2 Solar irradiation data: Actual data was used for 6 months and the balance data was obtained as per the procedure described in section 6.3.1 (Chapter 6). It was assumed that the site latitude is minus 40^0, the PV array faces due north and the slope of the array is equal to the angle of latitude. In addition, the albedo (ground reflectance) was assumed as 0.60 (Appendix J). These are supplied as default data in the computer program.

P.5.3 Hydro data: As per the procedure described in section 6.3.1 in Chapter 6. Moreover it was assumed that the plant is 80% efficient overall and that a 10% head loss occurs when delivering the rated capacity and that 10% of the stream water flow is by passed.

P.6 LOAD DATA: As per described in section 6.3.1 in Chapter 6 and Appendix N.

P.7 PROJECT COST DATA:

All cost components related to the project were the values suggested by the computer model (based on inbuilt equations described in the section M.4 of Appendix M).

P.8 PROJECT HARDWARE TECHNICAL DATA:

The input output characteristics, i.e. output power Vs input power (or the relevant proxy such as wind speed, fuel rate etc.) shall be as per the algorithms specified in the program. These include the generic WTG power curve, the generic inverter efficiency curve; the diesel gen set fuel curves etc. The following efficiencies were assumed in respect of the following converters:

(a) Maximum power point tracker efficiency = 90%

(b) Diesel gen set rectifier efficiency (applicable to category 1 gen sets only) = 95%

(c) Battery charger efficiency (applicable when a lead acid batteries are used as a distributed resource only) = 85%

P.8.1 Wind turbine generator (WTG) rotor axis height with rated capacity:

Since the wind turbine rotor axis height changes with the capacity of the WTG, the recommended tower height data were collected from published data for different WTG capacities (as specified by different sources) and the tower height (assumed to be equal to the rotor axis height) Vs. WTG crated capacity relationship was plotted as shown in Fig. P.1

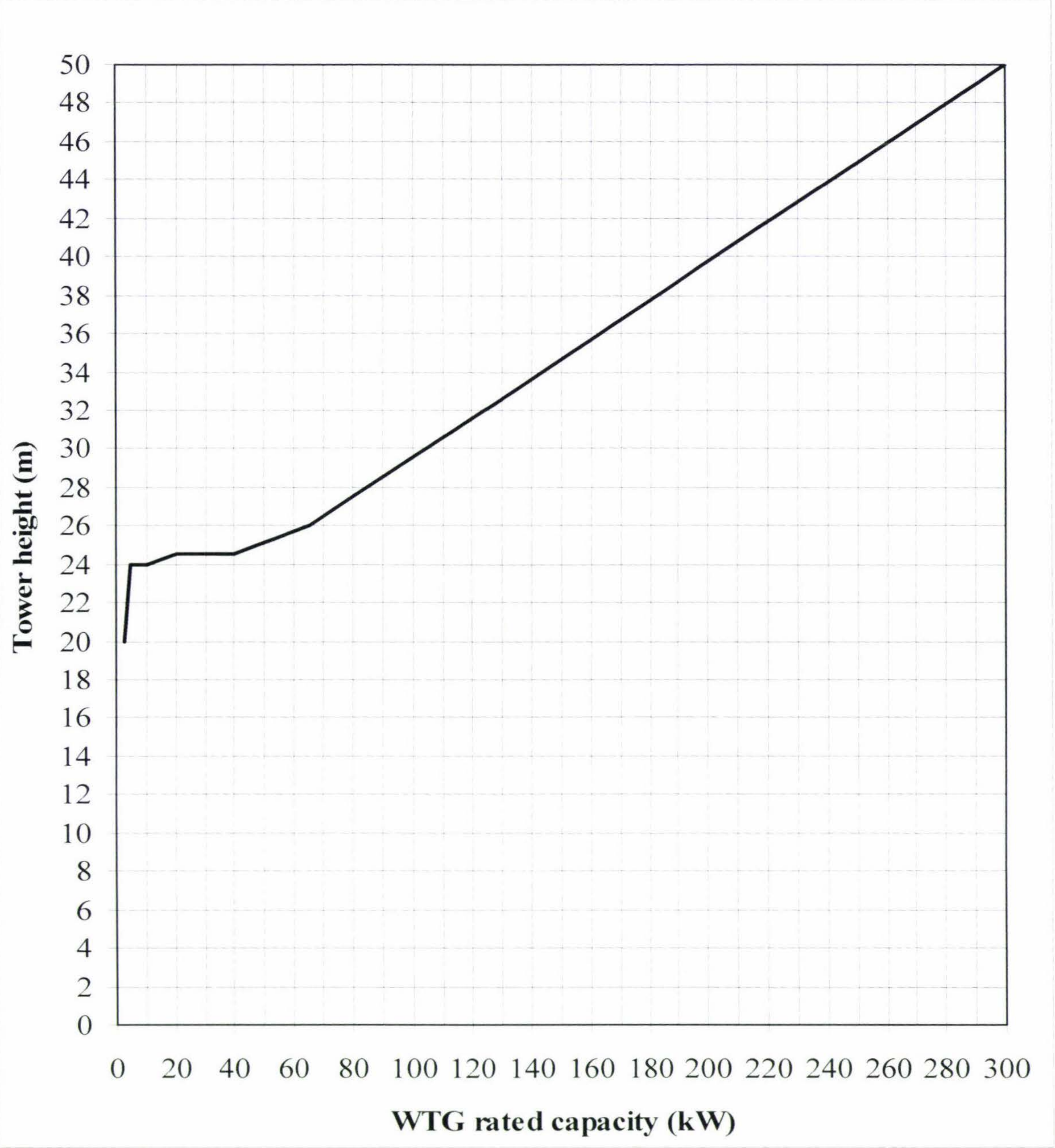


Fig. P.1: WTG turbine rotor axis height (i.e. tower height) Vs WTG rated capacity based on commercial HAWT manufacturer specifications

APPENDIX Q

Additional simulation results of the Totara Valley/Kumeroa case study model

Contents:

Section Q1: 3kW wind turbine generator application, under net metering

Project Name: **Totara Valley Project, Woodville, New Zealand**

Simulation Scenario: Zone A_3kW WTG_8m/s, net metering, no subsidy

Simulation Run No. ---

1. Wind turbine performance:

Category 1: Variable voltage/frequency alternator

Availability	Available
Unit capacity (kW)	3
Number of units	1
Gross annual kWh	11,241
Gross capacity factor (%)	43%
Initial investment	$32,302.80
O&M cost (per annum)	$0.00
Average wind speed (m/s)	8.0
Weibull k	2.00

Category 2: Induction/synchronous alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibull k	N/A

2. Photovoltaic (PV) performance:

Availability	Not available
Peak wattage (kW)	N/A
Array slope (Deg)	N/A
Gross annual kWh	0
Peak sun hrs. (HZ Surface)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

The model can be used for any PV array at any fixed orientation (in slope & azimuth) for any site latitude & meridian. Please see the solar worksheet for details.

3. Micro hydro performance:

Availability	Not available
Capacity (kW)	N/A
Type	N/A
Head (m)	N/A
Head loss (%)	N/A
Average flow via turbine (litres/s)	N/A
Gross annual kWh	0
Initial investment	N/A
O&M cost (per annum)	N/A

4. Inverter performance:

Availability	Available
Capacity (kW)	3
Initial investment	$7,503.25
O&M cost (per annum)	$66.99

5. Battery bank performance:

Availability	Not available
C_{25} rate per battey (Ah)	N/A
Load injection rate (kW)	N/A
Service hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

6. Fuel genset (diesel) performance:

Generator Type: Alternator via rec./inverter

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

Generator Type: Induction/synchronous

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

7. **Pumped hydro performance:**

Availability	Not available
Capacity (kW)	N/A
System gross head (m)	N/A
Turbine operating hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

8. **Metering information:**

Metering arrangement:

Simple bi directional (induction disc)
Net metering

Initial investment	$0.00
Charges on injection (per annum)	$0.00
O&M costs (per annum)	$0.00

9. **Customer load data:**

9.a. Summer Profile:

Seasonal mean (kW)	2.97
Seasonal median (kW)	2.59
Seasonal peak (kW)	14.71
Seasonal load factor (%)	0.20

9.b. Winter Profile:

Seasonal mean (kW)	2.57
Seasonal median (kW)	2.34
Seasonal peak (kW)	10.74
Seasonal load factor (%)	0.24

Energy consumption during the full year (kWh) = 24,265.86

10. **Electricity Market Information:** *(Reference year & GXP:2002, Haywards)*

10.a. Retailer Price Signals

Mean "spot price"/yr (c./kWh)	4
Standard deviation of the "spot price"/yr (c/kWh)	2
Annual spot price escalation	3.5%
Operating margin (as a % of expected spot price)	30.0%
Estimated "variable retail price" cts/kWh (this is not applicable to TOU metered customers)	12

Note: Peak period pricing (imposed by lines Co.) if any, is included in the rental (i.e. fixed charge)

10.b. Lines Company Price Signals

(i) Day line charge (c/kWh)	6.53
(ii) Night line charge (c/kWh)	4.35
(iii) Day & night charge rescale factor	1.0
(iv) Is maximum demand (MD) pricing existent?	N/A
(v) Tariff for MD ($/kVA/month)	$0.00
(vi) Is critical peak period demand pricing (CPPDP) existent?	N/A
(vii) Tariff for CPPDP ($/kVA/year)	N/A
(viii) Is critical peak period injection pricing (CPPIP) existent?	N/A
(ix) Basis of payment for (CPPIP)	N/A
(x) Tariff for CPPIP ($/kWh/year)	N/A
(xi) Tariff for CPPIP ($/kVA/year)	N/A
(xii) Total peak duration/annum (hrs)	0.00
(xiii) Fixed charge as a % of the bill	10.0%
(xiv) Calculated daily rental	$1.75

Notes on Lines Company Price Signals:

1. Day & night charge rescale factor (iii) above is a multiplication factor applied on the original charges referred to in (i) and (ii) above.

2. CPPDP referred to in (vi) above applies if the lines company prices its product (in addition to energy and if applicable, customer's maximum demand) on a basis of critical peak loads on the network.

3. CPPIP referred to in (viii) above applies if the lines company is able and willing to pay owners of DG during peak load situations referred to in Note 2. above. This payment is usually on the basis of average firm capacity provided (in average kVA) during the peak period (i.e. (xi) above). However, the signaling can also come in the form of firm energy provided during peak period times (i.e. (x) above).

4. The maximum demand charge referred to in (v) above applies to winter months only.

11. The data related to the project economics:

Initial investment ($)	$40,006.06
Investor's cost of capital (%)	5.00%
Borrowed funds on concessionary terms as a % of initial investment	0.0%
Annual interest rate for funds burrowed under concessionary terms	N/A
The payback (years)	30
Accounting rate of return(ARR)	3.3%

Project life	20 years
Risk premium	0.00%
Salvage value ($)	$0.00
Project discount rate (%)	5.0%
Net present cost (NPC)	$40,840.94
NPC/kWh generated (in NZ cents)	10
Net present value (NPV)	- $23,754.34
Internal rate of return (IRR)	0
Profitability index (PI)	NPV Negative

Foregone lines company revenue (per annum):

Due to lowered energy delivery	$542.15
Due to CPPDP pricing policy	$0.00
Due to MD pricing policy	$0.00
Less charges for grid injection	$0.00
Total foregone revenue…	$542.15

'MD' abbreviates' maximum demand'

Cost incurred by the lines company due to payments to DG owners for network support (firm energy/capacity) during critical peak periods:

Due to CPPIP pricing policy	$0.00

12. The sensitivity results:

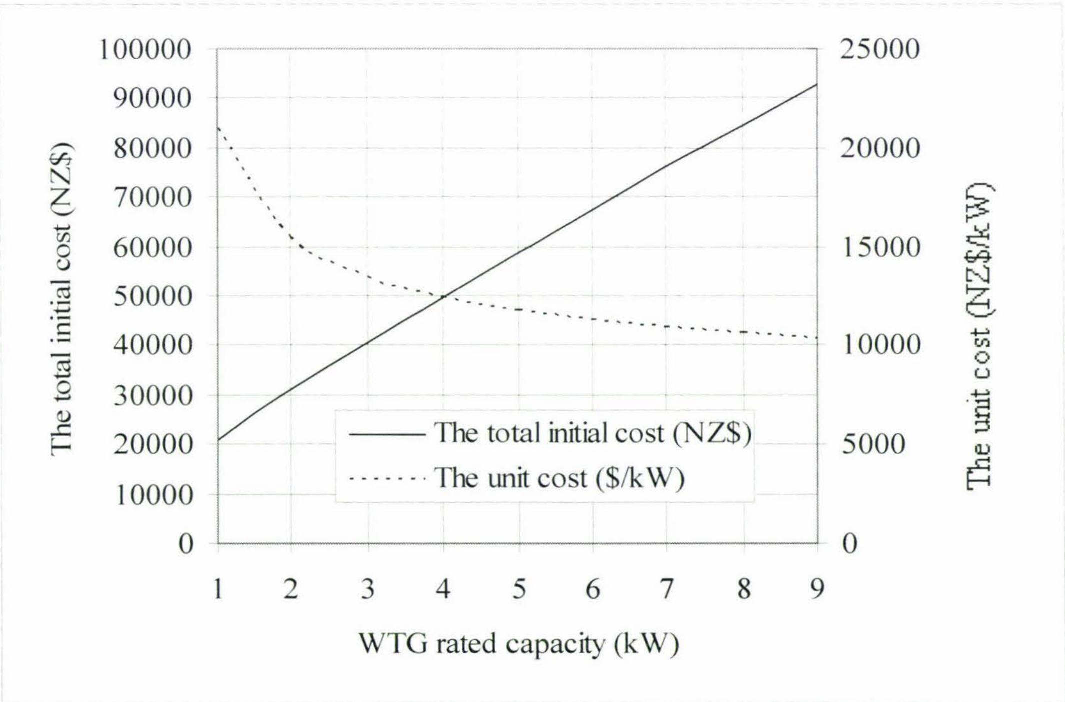


Fig. Q1: The variation of the initial cost structure and the unit cost with wind turbine rated capacity for a small grid connected wind project as outputted by the computer model

Comment: Fig. Q1 clearly indicates that even at smaller WTG capacity ranges (<10 kW), there is clear economies of scale (e.g. the unit cost drops from about $ 2100 for a 1 kW grid connected WTG system to about $ $ 1,100 for a 9 kW system).

Section Q2: Comparison of the favourability of ScanPower's pricing system for lines services with that of Orion New Zealand Limited for a small wind turbine generator application

I. Objectives, Background and methodology:

The objective of the simulation was to compare the revenue streams generated based on ScanPower's price structure with that of Orion's price structure under a net metering regime.

ScanPower, the lines company relevant to Torata Valley/Kumeroa communities charge its standard commercial customers and domestic customers based on a day and an evening variable charge of 6 c/kWh and 4 c/kWh respectively. These charges remain valid throughout the year for all days. Like other lines companies, SacnPower charges its customers in bulk, based on power flows at the GXP. These charges are charged to the retailers who in turn recover it from their customers. The simulation uses these charges adjusted by multiplying by the applicable loss factor, which is 1.08814 (based on a loss ratio of 8.1% stipulated).

Orion New Zealand Limited, the lines company operating in the Canterbury region, exercises peak period charges based on the peak period load in addition to the variable c/kWh day and evening charges. There are two distinct tariff structures for Orion's standard customers[1] based on the zone to which the customers belong; Zone A or B. This simulation used Zone A's tariff structure, which stands as follows:

- Day charge for weekdays: 0.74 c/kWh
- Evening charge for weekdays: 5.25 c/kWh
- Weekend charges (day or evening): 0.74 Cents/kWh
- Peak period charge: $120.00/average kVA/year
- Payment for firm capacity supplied by DG: $100/average kW/year *(for peak periods only)*

Note that since the computer model does not distinguish between weekdays and weekend, the weekday charges were applied to weekends as well. These charges were multiplied by 1.04 being the representative loss factor figure for Orion's zone A customers. For calculating the average kVA during peak periods, it was assumed that peak periods occur on 50 days in the winter with each peak period lasting one hour commencing at the 37th half hour time interval.

Simulations were run for a 6 kW wind turbine generator (WTG) operating on a very good wind regime of 8 m/s and a good wind regime of 6.0 m/s.

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[1] *In Orion's definition, standard customers are customers whose installed capacity is lower than 300 kVA.*

II. Results:

Revenue generated in the 1st year under ScanPower's price structure:- 8 m/s wind regime

Month	Payments for energy inject ($)	Avoided cost of grid energy ($/kWh)	Payments for firm energy or firm capacity provided during peak period ($/year)	Avoided peak period charges ($/year)
January	0.00	205.81		
February	0.00	193.31		
March	0.00	208.75		
April	0.00	209.73		
May	0.00	196.26		
June	0.00	196.38		
July	0.00	184.67		
August	0.00	168.95		
September	0.00	90.99		
October	0.00	187.00		
November	0.00	205.64		
December	0.00	208.17		
Whole year	$0.00	$2,255.67	$0.00	$0.00
Grand total cash inflow in year 1...			⇨ $2,255.67	

Revenue generated in the 1st year under ScanPower's price structure:- 6 m/s wind regime

Month	Payments for energy inject ($)	Avoided cost of grid energy ($/kWh)	Payments for firm energy or firm capacity provided during peak period ($/year)	Avoided peak period charges ($/year)
January	0.00	140.96		
February	0.00	161.01		
March	0.00	148.11		
April	0.00	161.83		
May	0.00	169.51		
June	0.00	137.28		
July	0.00	110.40		
August	0.00	93.79		
September	0.00	36.94		
October	0.00	113.15		
November	0.00	152.81		
December	0.00	145.96		
Whole year	$0.00	$1,571.75	$0.00	$0.00
Grand total cash inflow in year 1...			$1,571.75	

Revenue generated in the 1st year under Orion's price structure :- 8 m/s wind regime

Month	Payments for energy inject ($)	Avoided cost of grid energy ($/kWh)	Payments for firm energy or firm capacity provided during peak period ($/year)	Avoided peak period charges ($/year)
January	0.00	171.66		
February	0.00	160.05		
March	0.00	174.12		
April	0.00	174.93		
May	0.00	168.32		
June	0.00	163.53		
July	0.00	154.03		
August	0.00	140.92		
September	0.00	75.90		
October	0.00	155.97		
November	0.00	171.52		
December	0.00	173.63		
Whole year	$0.00	$1,884.59	$35.55	$278.92
Grand total cash inflow in year 1...			**$2,199.06**	

Revenue generated in the 1st year under Orion's price structure: - 6 m/s wind regime

Month	Payments for energy inject ($)	Avoided cost of grid energy ($/kWh)	Payments for firm energy or firm capacity provided during peak period ($/year)	Avoided peak period charges ($/year)
January	0.00	117.72		
February	0.00	134.47		
March	0.00	123.69		
April	0.00	135.15		
May	0.00	141.57		
June	0.00	114.65		
July	0.00	92.20		
August	0.00	78.33		
September	0.00	30.85		
October	0.00	94.50		
November	0.00	127.62		
December	0.00	121.90		
Whole year	$0.00	$1,312.66	$23.51	$151.64
Grand total cash inflow in year 1...			**$1,487.81**	

III. Conclusion:

Based on the above observations it can be concluded that Orion's pricing structure is not as disadvantageous as it looks, **provided its customers are metered for peak period generation/consumption** and hence paid/credited for capacity provided and lowering the peak period capacity drawn from the network (due to WTG generation), irrespective of the fact that the metering scheme in principle is "net metering."

Section Q3: 500Wp PV array application, under net metering

Project Name: **Totara Valley Project, Woodville, New Zealand**

Simulation Scenario: Zone A_PV 500W_net metering _no subsidy

Simulation Run No. ---

1. Wind turbine performance:

Category 1: Variable voltage/frequency alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibul k	N/A

Category 2: Induction/synchronous alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibul k	N/A

2. Photovoltaic (PV) performance:

Availability	Available
Peak wattage (kW)	0.500
Array slope (deg)	40
Gross annual kWh	715
Peak sun hrs. (HZ Surface)	3.9
Initial investment	$11,500.00
O&M cost (per annum)	$0.00

The model can be used for any PV array at any fixed orientation (in slope & azimuth) for any site latitude & meridian. Please see the solar worksheet for details.

3. Micro hydro performance:

Availability	Not available
Capacity (kW)	N/A
Type	N/A
Head (m)	N/A
Head loss (%)	N/A
Average flow via turbine (litres/s)	N/A
Gross annual kWh	0
Initial investment	N/A
O&M cost (per annum)	N/A

4. Inverter performance:

Availability	Available
Capacity (kW)	1
Initial investment	$3,295.25
O&M cost (per annum)	$29.42

5. Battery bank performance:

Availability	Not available
C25 rate per battey (Ah)	N/A
Load injection rate (kW)	N/A
Service hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

6. Fuel genset (diesel) performance:

Generator Type: Alternator via rec./inverter

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

Generator Type: Induction/synchronous

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

7. Pumped hydro performance:

Availability	Not available
Capacity (kW)	N/A
System gross head (m)	N/A
Turbine operating hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

8. Metering information:

Metering arrangement:

Simple bi directional (induction disc)

Net metering

Initial investment	$0.00
Charges on injection (per annum)	$0.00
O&M costs (per annum)	$0.00

9. Customer load data:

9.a. Summer Profile:

Seasonal mean (kW)	2.96
Seasonal median (kW)	2.54
Seasonal peak (kW)	13.91
Seasonal load factor (%)	0.21

9.b. Winter Profile:

Seasonal mean (kW)	2.57
Seasonal median (kW)	2.34
Seasonal peak (kW)	11.86
Seasonal load factor (%)	0.22

Energy consumption during the full year (kWh) = 24,214.48

10. Electricity Market Information: *(Reference year & GXP:2002, Haywards)*

10.a. Retailer Price Signals

Mean "spot price"/yr (c/kWh)	4
Standard deviation of the "spot price"/yr (c/kWh)	2
Annual spot price escalation	3.5%
Operating margin (as a % of expected spot price)	30.0%
Estimated "variable retail price" cts/kWh (this is not applicable to TOU metered customers)	12

Note: Peak period pricing (imposed by lines Co.) if any, is included in the rental (i.e. fixed charge)

10.b. Lines Company Price Signals

(i) Day line charge (c/kWh)	6.53
(ii) Night line charge (c/kWh)	4.35
(iii) Day & night charge rescale factor	1.0
(iv) Is maximum demand (MD) pricing existent?	N/A
(v) Tariff for MD ($/kVA/month)	$0.00
(vi) Is critical peak period demand pricing (CPPDP) existent?	N/A
(vii) Tariff for CPPDP ($/kVA/year)	N/A
(viii) Is critical peak period injection pricing (CPPIP) existent?	N/A
(ix) Basis of payment for (CPPIP)	N/A
(x) Tariff for CPPIP ($/kWh/year)	N/A
(xi) Tariff for CPPIP ($/kVA/year)	N/A
(xii) Total peak duration/annum (hrs)	0.00
(xiii) Fixed charge as a % of the bill	10.0%
(xiv) Calculated daily rental	$1.75

Notes on Lines Company Price Signals:

1. Day & night charge rescale factor (iii) above is a multiplication factor applied on the original charges referred to in (i) and (ii) above.

2. CPPDP referred to in (vi) above applies if the lines company prices its product (in addition to energy and if applicable, customer's maximum demand) on a basis of critical peak loads on the network.

3. CPPIP referred to in (viii) above applies if the lines company is able and willing to pay owners of DG during peak load situations referred to in Note 2. above. This payment is usually on the basis of average firm capacity provided (in average kVA) during the peak period (i.e. (xi) above). However, the signaling can also come in the form of firm energy provided during peak period times (i.e. (x) above).

4. The maximum demand charge referred to in (v) above applies to winter months only.

11. The data related to the project economics:

Initial investment ($)	$15,345.25
Investor's cost of capital (%)	5.00%
Borrowed funds on concessionary terms as a % of initial investment	0.0%
Annual interest rate for funds burrowed under concessionary terms	
The payback (years)	957.41
Accounting rate of return (ARR)	0.1%

Project life	20 years
Risk premium	0.00%
Salvage value ($)	$0.00
Project discount rate (%)	5.0%
Net present cost (NPC)	$9,808.78
NPC/kWh generated (in NZ cents)	41
Net present value (NPV)	- $8,813.79
Internal rate of return (IRR)	0
Profitability index (PI)	NPV Negati

Foregone lines company revenue (per annum):

-

Due to lowered energy delivery	$34.73
Due to CPPDP pricing policy	$0.00
Due to MD pricing policy	$0.00
Less charges for grid injection	$0.00
Total foregone revenue...	$34.73

'MD' abbreviates ' maximum demand'

Cost incurred by the lines company due to payments to DG owners for network support (firm energy/capacity) during critical peak periods:

Due to CPPIP pricing policy	$0.00

12. The sensitivity results:

--- *None* ---

Section Q4: 6.5kW low cost micro hydro application, under net metering

Project Name: **Totara Valley Project, Woodville, New Zealand**

Simulation Scenario: Zone A_6.5kW_lowcostMH_net metering _no subsidy

Simulation Run No. ---

1. Wind turbine performance:

Category 1: Variable voltage/frequency alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibul k	N/A

Category 2: Induction/synchronous alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibul k	N/A

2. Photovoltaic (PV) performance:

Availability	Not available
Peak wattage (kW)	N/A
Array slope (deg)	N/A
Gross annual kWh	0
Peak sun hrs. (HZ Surface)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

The model can be used for any PV array at any fixed orientation (in slope & azimuth) for any site latitude & meridian. Please see the solar worksheet for details.

3. Micro hydro performance:

Availability	Available
Capacity (kW)	6.50
Type	Low Cost
Head (m)	13.5
Head loss (%)	10.0%
Average flow via turbine (litres/s)	59.0
Gross annual kWh	41,359
Initial investment	$16,250.00
O&M cost (per annum)	$487.50

4. Inverter performance:

Availability	Not available
Capacity (kW)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

5. Battery bank performance:

Availability	Not available
C_{25} rate per battey (Ah)	N/A
Load injection rate (kW)	N/A
Service hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

6. Fuel genset (diesel) performance:

Generator Type: Alternator via rec./inverter

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

Generator Type: Induction/synchronous

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

7. **Pumped hydro performance:**

Availability	Not available
Capacity (kW)	N/A
System gross head (m)	N/A
Turbine operating hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

8. **Metering information:**

Metering arrangement:

Simple bi directional (induction disc)
Net metering

Initial investment	$0.00
Charges on injection (per annum)	$0.00
O&M costs (per annum)	$0.00

9. **Customer load data:**

9.a. Summer Profile:

Seasonal mean (kW)	2.94
Seasonal median (kW)	2.56
Seasonal peak (kW)	14.04
Seasonal load factor (%)	0.19

9.b. Winter Profile:

Seasonal mean (kW)	2.58
Seasonal median (kW)	2.35
Seasonal peak (kW)	10.96
Seasonal load factor (%)	0.23

Energy consumption during the full year (kWh) = 24,148.26

10. **Electricity Market Information:** *(Reference year & GXP:2002, Haywards)*

10.a. Retailer Price Signals

Mean "spot price"/yr (c/kWh)	4
Standard deviation of the "spot price"/yr (c/kWh)	2
Annual spot price escalation	3.5%
Operating margin (as a % of expected spot price)	30.0%
Estimated "variable retail price" cts/kWh (this is not applicable to TOU metered customers)	12

Note: Peak period pricing (imposed by lines Co.) if any, is included in the rental (i.e. fixed charge)

10.b. Lines Company Price Signals

(i) Day line charge (c/kWh)	6.53
(ii) Night line charge (c/kWh)	4.35
(iii) Day & night charge rescale factor	1.0
(iv) Is maximum demand (MD) pricing existent?	N/A
(v) Tariff for MD ($/kVA/month)	$0.00
(vi) Is critical peak period demand pricing (CPPDP) existent?	N/A
(vii) Tariff for CPPDP ($/kVA/year)	N/A
(viii) Is critical peak period injection pricing (CPPIP) existent?	N/A
(ix) Basis of payment for (CPPIP)	N/A
(x) Tariff for CPPIP ($/kWh/year)	N/A
(xi) Tariff for CPPIP ($/kVA/year)	N/A
(xii) Total peak duration/annum (hrs)	0.00
(xiii) Fixed charge as a % of the bill	10.0%
(xiv) Calculated daily rental	$1.75

Notes on Lines Company Price Signals:

1. Day & night charge rescale factor (iii) above is a multiplication factor applied on the original charges referred to in (i) and (ii) above.

2. CPPDP referred to in (vi) above applies if the lines company prices its product (in addition to energy and if applicable, customer's maximum demand) on a basis of critical peak loads on the network.

3. CPPIP referred to in (viii) above applies if the lines company is able and willing to pay owners of DG during peak load situations referred to in Note 2. above. This payment is usually on the basis of average firm capacity provided (in average kVA) during the peak period (i.e. (xi) above). However, the signaling can also come in the form of firm energy provided during peak period times (i.e. (x) above).

4. The maximum demand charge referred to in (v) above applies to winter months only.

There are three very good reasons as to why the fraction [NPC/kWh] is as low as of 1 cent/kWh in page Q-12. They are:

- **NPC being not levelised.** The levelised NPC/kWh figure (i.e. the tariff that would need to be charged for the energy in order to recoup the life cycle costs) is more informative and perhaps should have been indicated as an additional project performance indicator in the model. The levelised NPC/kWh figure is obtained by dividing the life cycle cost for the system by the sum of the units of energy produced by the system discounted over time. The model does not discount the kWh figures over time, as NPC is never used as a project performance indicator. Since the "present value factor" is approximately 39% for a 20 year project @ 5% discount rate, the NPC/kWh figure has to be divided by 0.39 to obtain the levelised cost, which amounts to 3 cts/kWh (after rounding off).

- **Very Low cost structure.** The project under consideration consists of a very low cost structure being a low cost (reversed engineered) pump version. The initial cost (and hence the life cycle cost) is only about 30% of that of a conventional technology such as cross flow technology (Fig. Q.2). Thus the NPC figure of a conventional technology would be about 3.3 times grater than that of the low cost technology (since 1/0.3 ≈ 3.3).

- **Exceedingly high-energy generation.** Due to very favourable hydro flows, the unit generates about twice the energy that is required for the farm per year (note from Page Q-10 that the unit generates 41,359 kWh per annum as against the farm requirement of 24,148.26 kWh per annum, as shown in Page Q-11). In most cases (involving small renewable DG), the energy generation is typically less than or equal to 100% of the load. Hence for a typical very small micro hydro project, the NPC/kWh would be at least 2 times grater than that of the low cost technology.

Combining the above three factors together, the levelised NPC/kWh for a typical very small micro hydro project would be about 20 cts/kWh (since 3*3.3*2 ≈ 20)!!

11. The data related to the project economics:

Initial investment ($)	$16,450.00
Investor's cost of capital (%)	5.00%
Borrowed funds on concessionary terms as a % of initial investment	0.0%
Annual interest rate for funds burrowed under concessionary terms	
The payback (years)	4.00
Accounting rate of return (ARR)	24.2%

Project life	20 years
Risk premium	0.00%
Salvage value ($)	$0.00
Project discount rate (%)	5.0%
Net present cost (NPC)	$22,525.33
NPC/kWh generated (in NZ cents)	1
Net present value (NPV)	$31056.90
Internal rate of return (IRR)	24.0%
Profitability index (PI)	1.89

Foregone lines company revenue (per annum):

Due to lowered energy delivery	$1,305.15
Due to CPPDP pricing policy	$0.00
Due to MD pricing policy	$0.00
Less charges for grid injection	$0.00
Total foregone revenue…	$1,305.15

'MD' abbreviates' maximum demand'

Cost incurred by the lines company due to payments to DG owners for network support (firm energy/capacity) during critical peak periods:

Due to CPPIP pricing policy	$0.00

12. The sensitivity results:

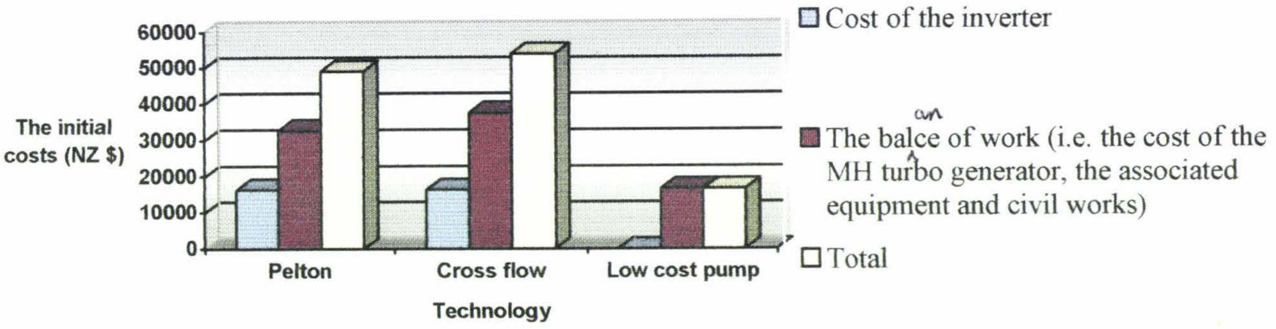

Fig. Q.2: The initial cost structure of 6.5 kW MH units of different technologies (as outputted by the computer model)

Section Q5: 4.5kW low cost micro hydro application for Totara Valley [revised flow rates], under gross import/gross export metering

Project Name: **Totara Valley Project, Woodville, New Zealand**

Simulation Scenario: Zone A_4.5kW_lowcostMH_gross import gross export _no subsidy

Simulation Run No. ---

1. Wind turbine performance:

Category 1: Variable voltage/frequency alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibul k	N/A

Category 2: Induction/synchronous alternator

Availability	Not available
Unit capacity (kW)	N/A
Number of units	N/A
Gross annual kWh	0
Gross capacity factor (%)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A
Average wind speed (m/s)	N/A
Weibul k	N/A

2. Photovoltaic (PV) performance:

Availability	Not available
Peak wattage (kW)	N/A
Array slope (deg)	N/A
Gross annual kWh	0
Peak sun hrs. (HZ Surface)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

The model can be used for any PV array at any fixed orientation (in slope & azimuth) for any site latitude & meridian. Please see the solar worksheet for details.

3. Micro hydro performance:

Availability	Available
Capacity (kW)	4.50
Type	Low Cost
Head (m)	13.5
Head loss (%)	10.0%
Average flow via turbine (litres/s)	39.9
Gross annual kWh	30,815
Initial investment	$11,250.00
O&M cost (per annum)	$337.50

4. Inverter performance:

Availability	Not available
Capacity (kW)	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

5. Battery bank performance:

Availability	Not available
C25 rate per battey (Ah)	N/A
Load injection rate (kW)	N/A
Service hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

6. Fuel genset (diesel) performance:

Generator Type: Alternator via rec./inverter

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

Generator Type: Induction/synchronous

Availability	Not available
Unit capacity (kW)	N/A
Gross annual kWh	0
Annual operating hours	N/A
Annual fuel consumption (lit)	N/A
Gross thermal efficiency (%)	N/A
Initial investment	N/A
Annual fuel cost	N/A
Annual O&M cost (excl. fuel)	N/A

(The gross thermal efficiency is LCV based)

7. Pumped hydro performance:

Availability	Not available
Capacity (kW)	N/A
System gross head (m)	N/A
Turbine operating hours/yr.	N/A
Initial investment	N/A
O&M cost (per annum)	N/A

8. Metering information:

Metering arrangement:

IMP/EXP Energy via.
Electronic TOU metering....>

Initial investment	$550.00
Charges on injection (per annum)	$0.00
O&M costs (per annum)	$0.00

9. Customer load data:

9.a. Summer Profile:

Seasonal mean (kW)	2.90
Seasonal median (kW)	2.52
Seasonal peak (kW)	13.01
Seasonal load factor (%)	0.22

9.b. Winter Profile:

Seasonal mean (kW)	2.57
Seasonal median (kW)	2.35
Seasonal peak (kW)	10.96
Seasonal load factor (%)	0.23

Energy consumption during the full year (kWh) = 24,001.62

10. Electricity Market Information: *(Reference year & GXP:2002, Haywards)*

10.a. Retailer Price Signals

Mean "spot price"/yr (c/kWh)	4
Standard deviation of the "spot price"/yr (c/kWh)	2
Annual spot price escalation	3.5%
Operating margin (as a % of expected spot price)	30.0%
Estimated "variable retail price" cts/kWh (this is not applicable to TOU metered customers)	12

Note: Peak period pricing (imposed by lines Co.) if any, is included in the rental (i.e. fixed charge)

10.b. Lines Company Price Signals

(i) Day line charge (c/kWh)	6.53
(ii) Night line charge (c/kWh)	4.35
(iii) Day & night charge rescale factor	1.0
(iv) Is maximum demand (MD) pricing existent?	N/A
(v) Tariff for MD ($/kVA/month)	$0.00
(vi) Is critical peak period demand pricing (CPPDP) existent?	N/A
(vii) Tariff for CPPDP($/kVA/year)	N/A
(viii) Is critical peak period injection pricing (CPPIP) existent?	N/A
(ix) Basis of payment for (CPPIP)	N/A
(x) Tariff for CPPIP ($/kWh/year)	N/A
(xi) Tariff for CPPIP ($/kVA/year)	N/A
(xii) Total peak duration/annum(hrs)	0.00
(xiii) Fixed charge as a % of the bill	10.0%
(xiv) Calculated daily rental	$1.75

Notes on Lines Company Price Signals:

1. Day & night charge rescale factor (iii) above is a multiplication factor applied on the original charges referred to in (i) and (ii) above.

2. CPPDP referred to in (vi) above applies if the lines company prices its product (in addition to energy and if applicable, customer's maximum demand) on a basis of critical peak loads on the network.

3. CPPIP referred to in (viii) above applies if the lines company is able and willing to pay owners of DG during peak load situations referred to in Note 2. above. This payment is usually on the basis of average firm capacity provided (in average kVA) during the peak period (i.e. (xi) above). However, the signaling can also come in the form of firm energy provided during peak period times (i.e. (x) above).

4. The maximum demand charge referred to in (v) above applies to winter months only.

11. The data related to the project economics:

Initial investment ($)	$11,800.00
Investor's cost of capital (%)	5.00%
Borrowed funds on concessionary terms as a % of initial investment	0.0%
Annual interest rate for funds burrowed under concessionary terms	
The payback (years)	3.94
Accounting rate of return (ARR)	25.4%

Project life	20 years
Risk premium	0.00%
Salvage value ($)	$0.00
Project discount rate (%)	5.0%
Net present cost (NPC)	$16,006.00
NPC/kWh generated (in NZ cents)	1
Net present value (NPV)	$24,127.82
Internal rate of return (IRR)	25.0%
Profitability index (PI)	2.04

Foregone lines company revenue (per annum):

Due to lowered energy delivery	$1,230.53
Due to CPPDP pricing policy	$0.00
Due to MD pricing policy	$0.00
Less charges for grid injection	$0.00
Total foregone revenue…	$1,230.53

'MD' abbreviates 'maximum demand'

Cost incurred by the lines company due to payments to DG owners for network support (firm energy/capacity) during critical peak periods:

Due to CPPIP pricing policy	$0.00

12. The sensitivity results:

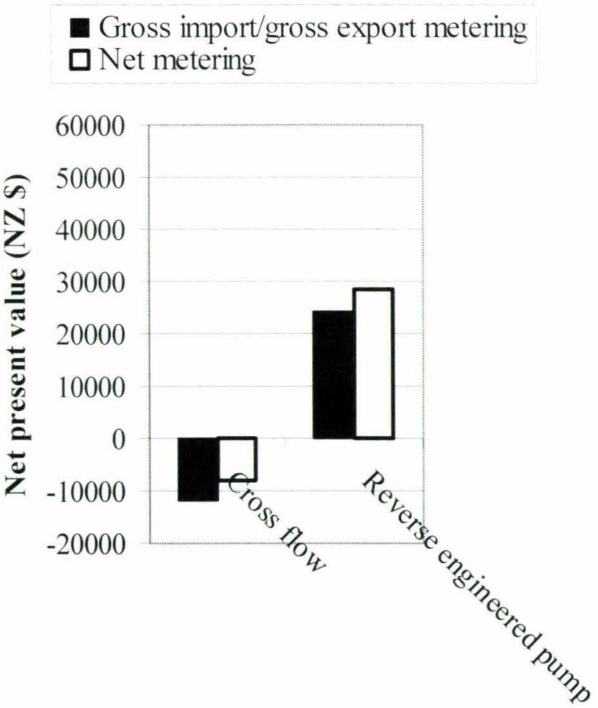

Fig. Q.3: The financial viability of 4.5 kW MH MH projects of different technologies under no subsidy

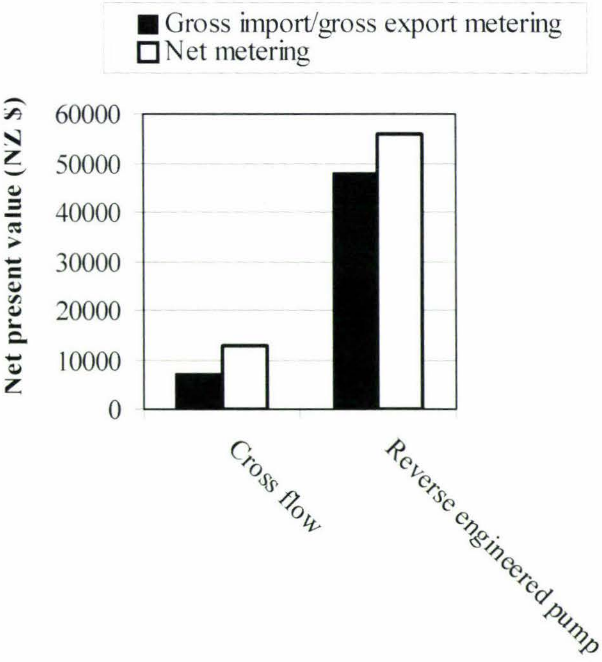

Fig. Q.4: The financial viability of 4.5 kW MH projects with full investment met via an interest free loan

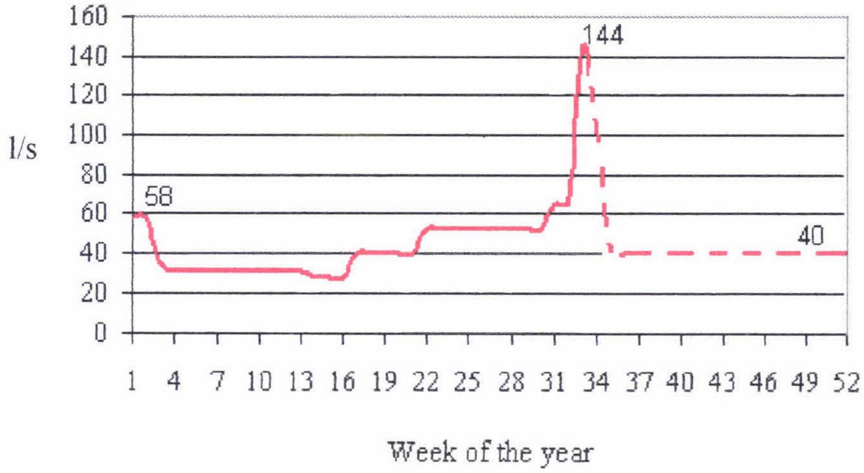

Fig. Q.5: The water flow rate of the Totara stream used for the simulation

(Note that the portion depicted in dotted red lines covers the estimated flow rates due to non availability of actual data)

Section Q6: Additional sensitivity results of small to medium wind diesel hybrid applications for Zone A through Zone C

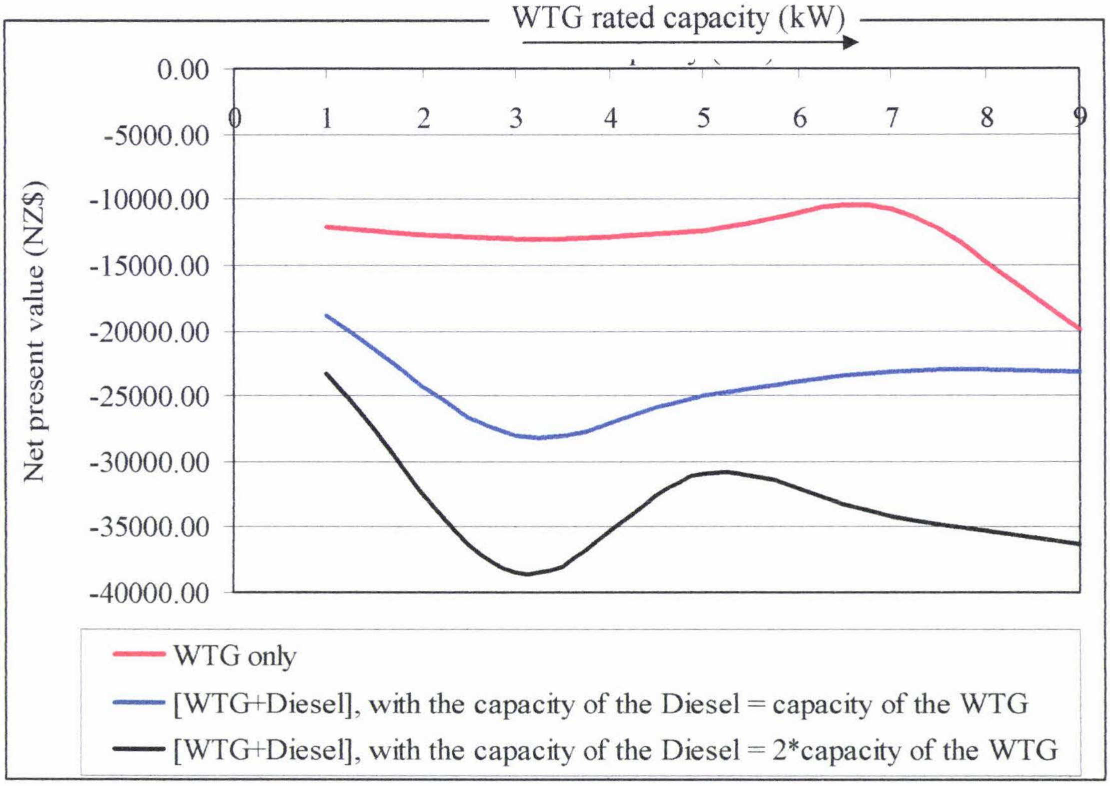

Fig. Q.6: The financial viability of a subsidised small conventional grid connected, net metered wind diesel hybrid system under payment for capacity provided as described below.

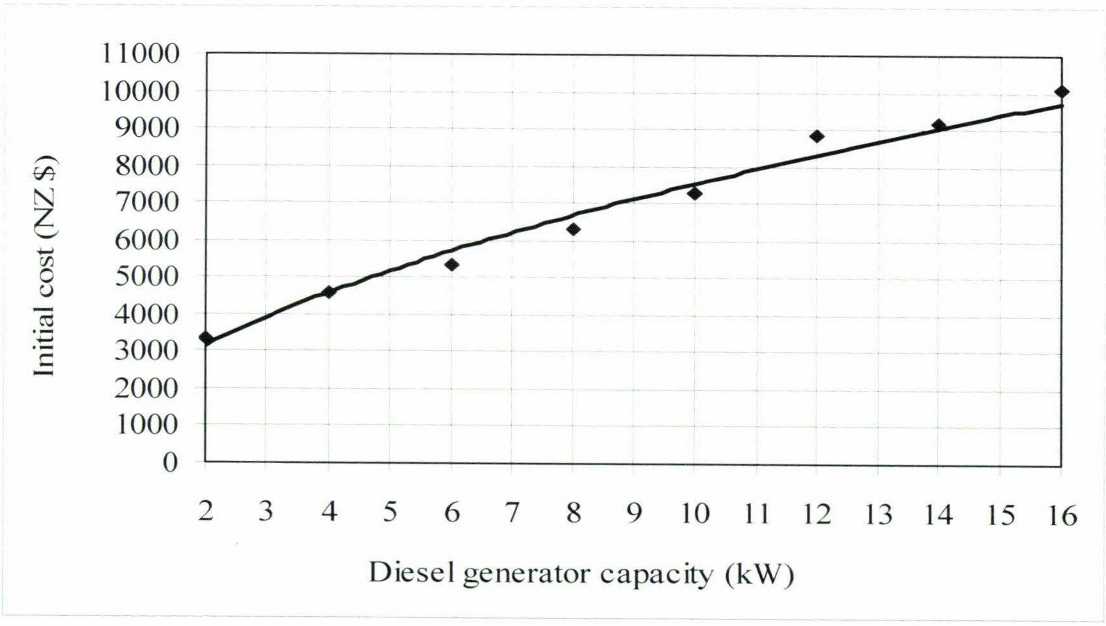

Fig. Q.7: The initial cost structure of a low cost diesel generating option involving a reconditioned diesel engine and an induction generator with the starting and interfacing equipment

With regard to Fig. Q.6, the system comprises of a standby generator, rectifier and an inverter. Also note that the wind regime applicable is 8 m/s. The diesel generator was assumed to be operating on 10 days in the winter one hour each in response to critical peak periods. The initial cost related to WTG, inverter and its associated auxiliaries being met by an interest free loan while the diesel generator and it's associated costs being met by usual funding sources that carry a cost of capital (base case: diesel only).

With regard to Fig. Q.7, note that in constructing initial costs through simulation, it was assumed that a reconditioned diesel engine-induction motor arrangement costs exactly 40% of that of a brand new diesel standby generator available in the market, the rectifier and other related auxiliary equipment (e.g. fuel tank).

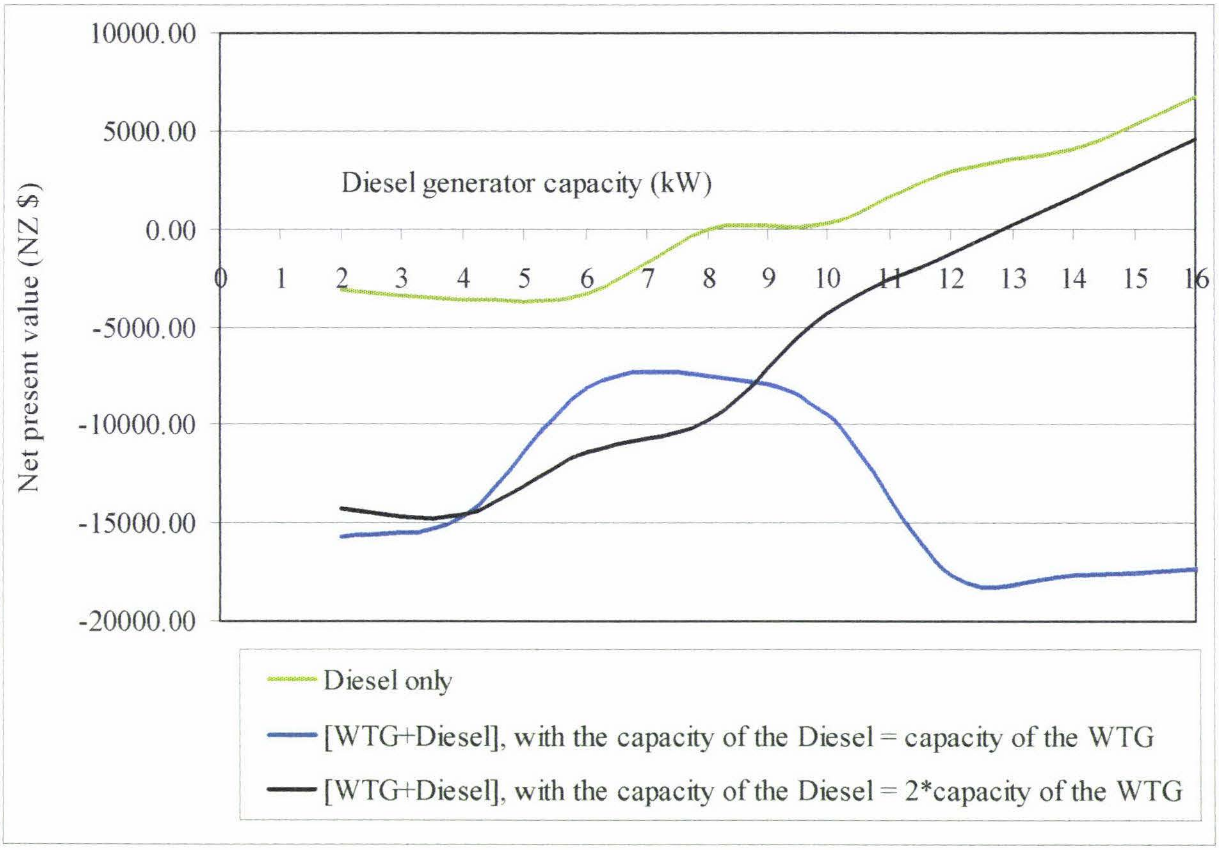

Fig. Q.8: The financial feasibility of a small low cost grid connected, net-metered wind diesel hybrid system.

Note that in Fig. Q7 and Q.8, low cost means a reconditioned diesel engine an induction motor (used as a generator) with the starting and interfacing equipment. Also note that the wind regime applicable is 8 m/s. The diesel generator was assumed to be operating on 10 days in the winter one hour each in response to critical peak periods. The initial cost related to WTG, inverter and its associated auxiliaries being met by an interest free loan while the diesel generator and it's associated costs being met by usual funding sources that carry a cost of capital (base case: diesel only).

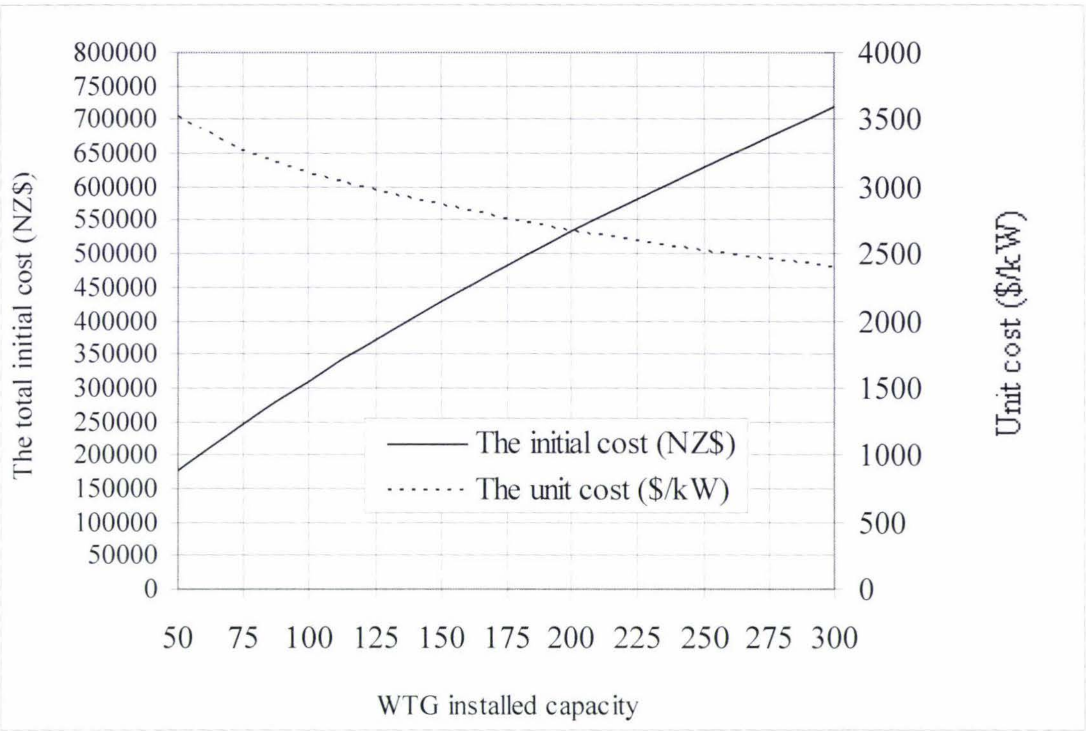

Fig Q9: The initial cost structure of a medium grid connected wind turbine (as outputted by the computer model)

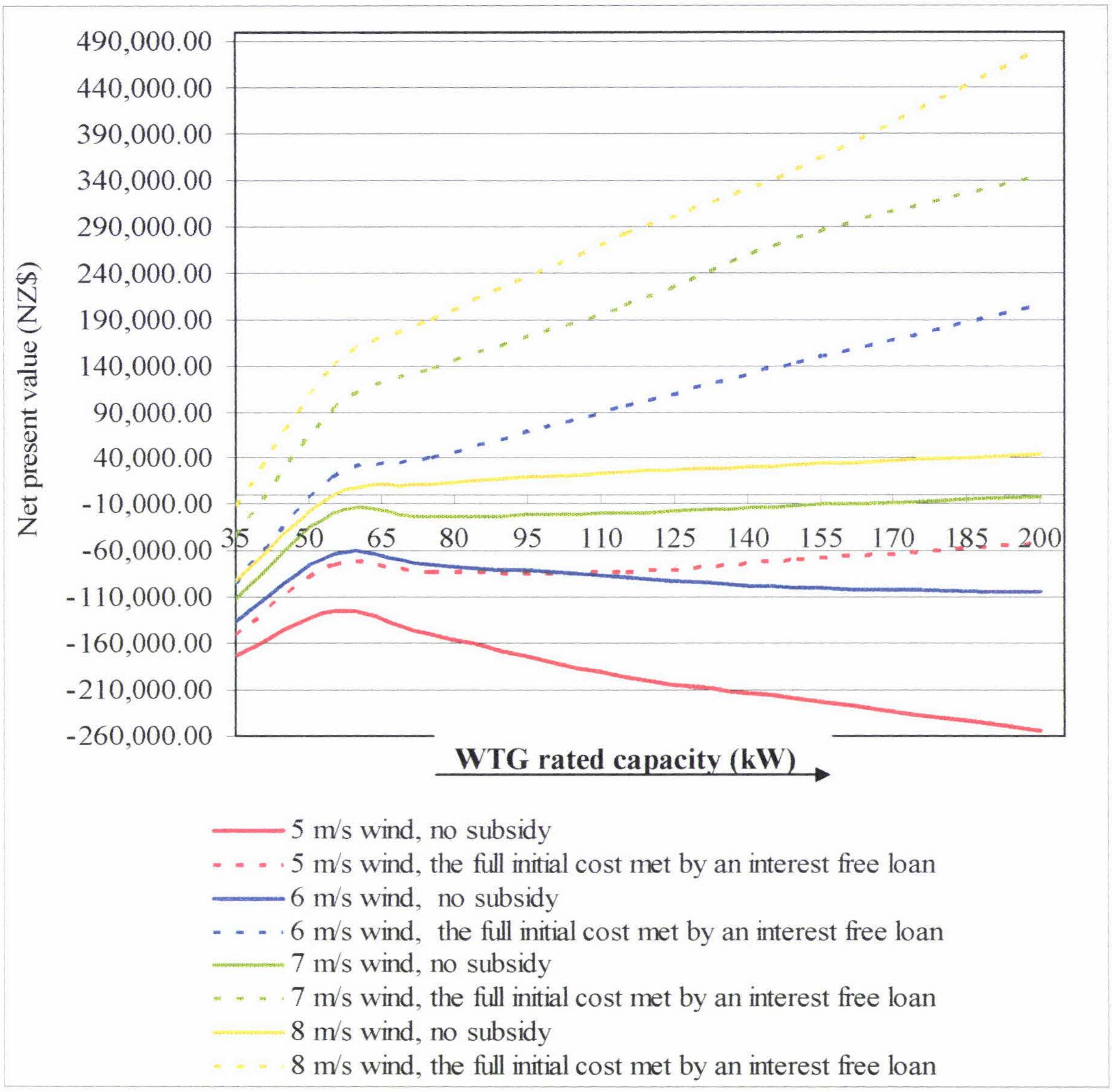

Fig. Q.10: The financial viability of medium grid connected, gross import gross export metered WTGs for Totara Valley Zone C

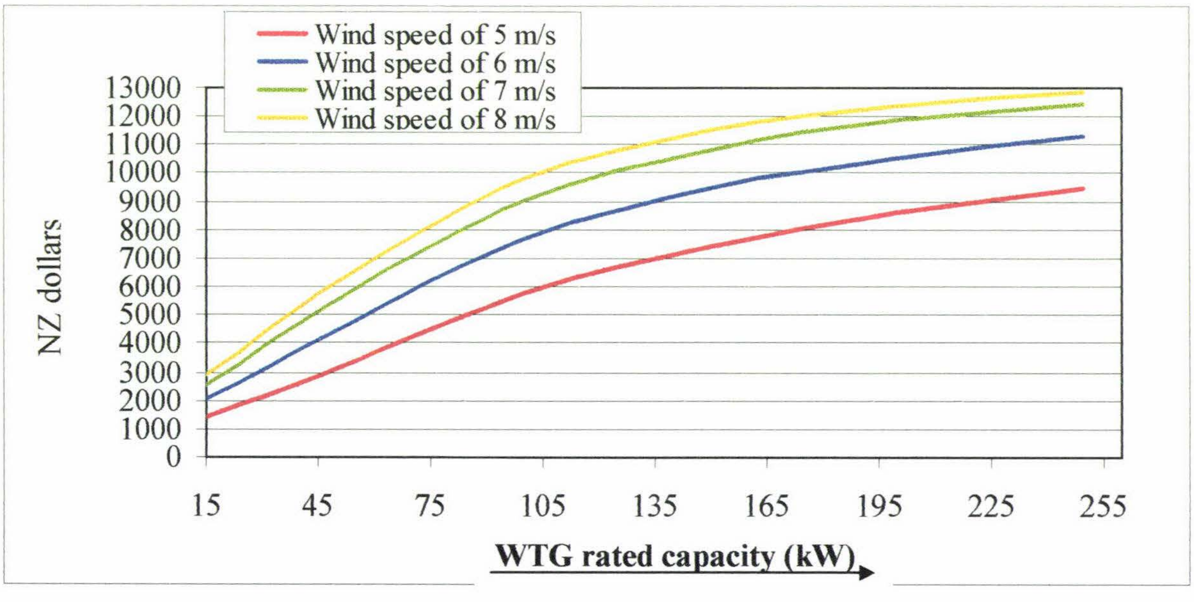

Fig. Q.11: The annual foregone revenue of a lines company under a gross import gross export metering scheme for different WTG capacities under different wind regimes under existing line charges for Totara Valley Zone C

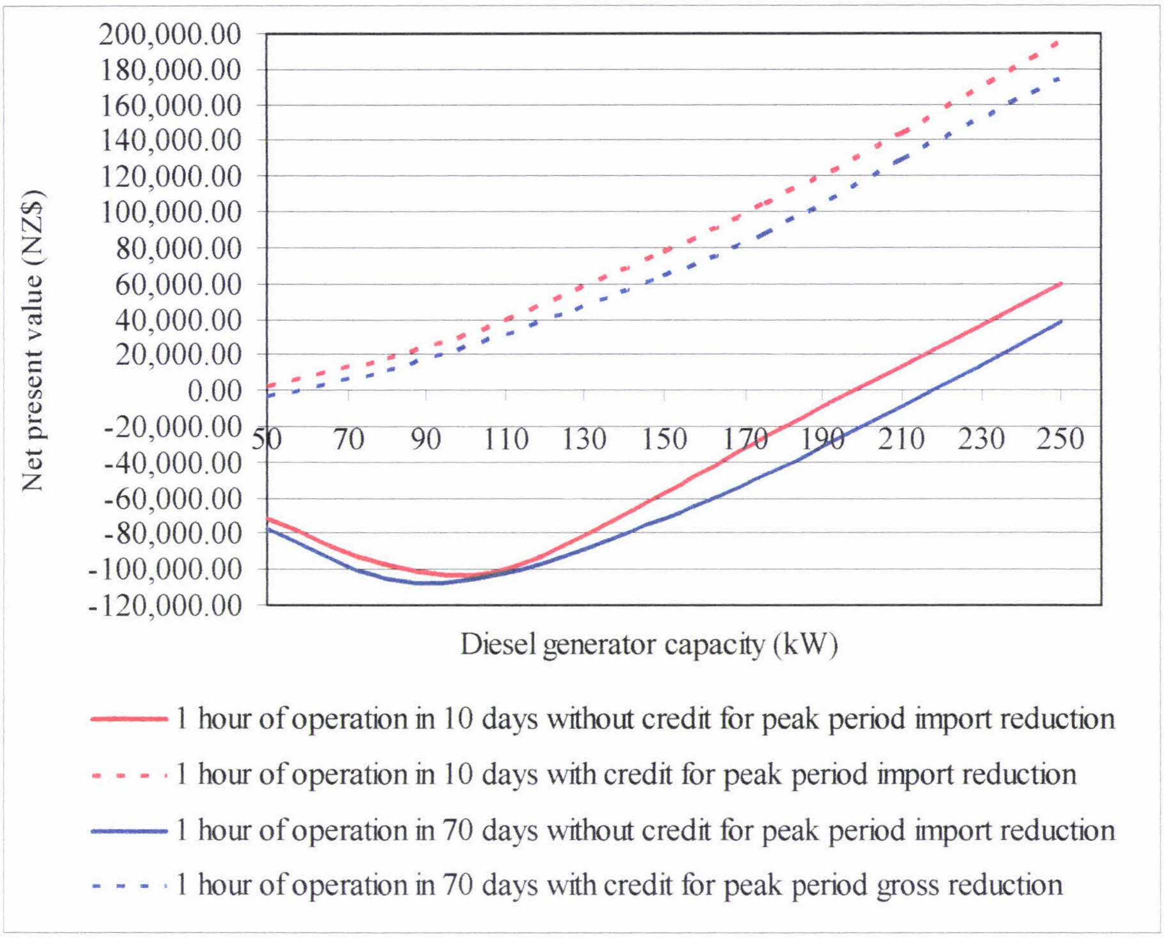

Fig.Q.12: The financial viability of a grid connected, gross import/gross export metered standby diesel generator operating in Totara Valley Zone C under a lines company incentive scheme for providing firm capacity during winter

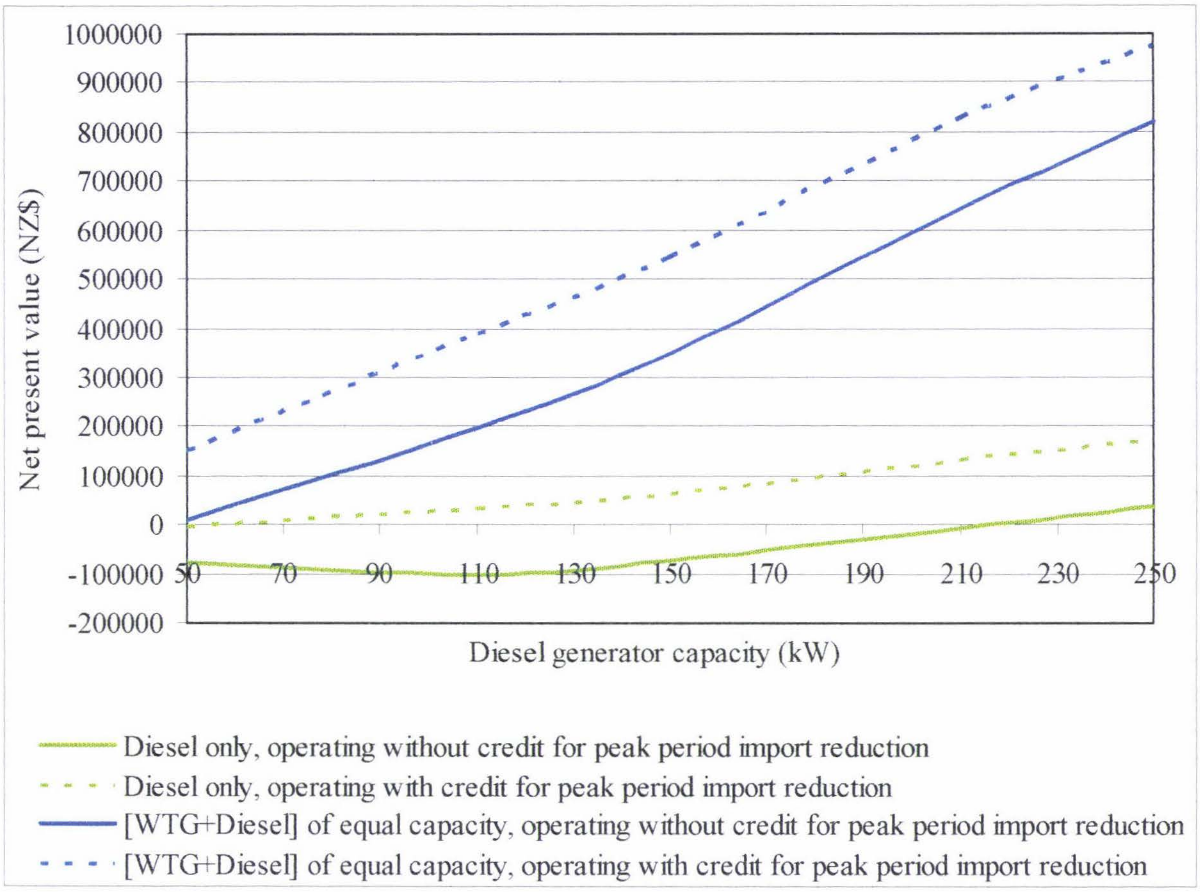

Fig.Q.13: The financial viability of a gross import/gross export metered wind diesel hybrid system for Totara Valley Zone C.

With regard to Fig. Q13, note that the wind regime applicable is 8 m/s. The diesel generator was assumed to be operating on 10 days in the winter one hour each in response to critical peak periods. Also note that the initial cost related to WTG, and its associated auxiliaries being met by an interest free loan while the diesel generator and it's associated costs being met by usual funding sources that carry a cost of capital (base case: diesel only).

Errata

Page 1, Footnote 1: Clark (1999) to be replaced with Clark *et al* (1999).

Page 53, paragraph 1, line 6: Delete the words "of late"

Page 65, paragraph 3, lines 3 & 4: Replace the words "vapour ammonia" with the word "absorption"

Page 80, paragraph 2, line 4: Replace the word "been" with "being"

Page 98, paragraph 1, line 7: Insert the words "firm energy/capacity" between the two words "for" and "supplied"

Page 101, paragraph 2, line 5: Replace the word "corporate" with "co-operate"

Page 103, paragraph 1, line 1: Insert the word "for" between the two words "reason" and "studying"

Page 160, paragraph 1, line 3: Replace the word "proton" with "proportion"

Page 171, paragraph 1, line 2: Replace the word "temperate" with "temperature"

Page 221, paragraph 2, line 7: Bring the word "always" before the word "provide"

Page 227, paragraph 2, line 4: Merge the words "net work" to form "network"

Page L-7, paragraph 2, line 2: Replace the phrase "array (i.e. Eq.) has been" with the phrase "array (i.e. Eq. L.8 through L.13) have been "

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