Systems to Implement Demand Response in New Zealand

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Abstract

According to the Federal Energy Regulatory Commission, Demand Response (DR) is defined as: "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." In the US, experience with regional electricity markets suggests that active DR is crucial to both power system reliability and market efficiency. Accordingly, efforts to enable demand-side participation in the US are providing significant opportunities for end-customers, load serving entities, and independent system operators. In New Zealand, a number of DR initiatives exist or are coming online. Given the importance of DR initiatives and systems to enable participation in the demand side of the market, the purpose of this paper is to provide a detailed understanding of the various systems already installed, and potentially required, to implement DR in New Zealand.

Types of DR considered include interruptible load, Transpower's demand response initiatives, demand side bidding and forecasting, dispatchable demand, and ripple control. This paper also reviews which groups of market participants are using DR, and for what purpose.

Currently, most DR is incentive based, but the deployment of smart meters at consumers' premises may lead to significant adoption of price based DR, such as initiatives to introduce time of use and peak pricing to domestic users. Home Energy Management Systems (HEMS) have been defined as any product or service that monitors, controls, or analyzes energy in the home, and may be utility or non-utility based. HEMS and the initiatives mentioned form a rapidly emerging fabric of DR systems in NZ.

1. Introduction

According to the Federal Energy Regulatory Commission, Demand Response (DR) is defined as: “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [1].” In the US, experience with regional electricity markets suggests that active DR is crucial to both power system reliability and market efficiency [2]. Accordingly, efforts to enable demand-side participation in the US are providing significant opportunities for end-customers, load serving entities, and independent system operators [2]. In New Zealand, a number of DR initiatives exist or are coming online. Given the importance of DR initiatives and systems to enable participation in the demand side of the market, the purpose of this paper is to provide a detailed understanding of the various systems already installed, and potentially required, to implement DR in New Zealand. This paper also reviews which groups of market participants are using DR, and for what purpose. Figure 1 illustrates the monetary values and speed of response timescales of various forms of DR in NZ.

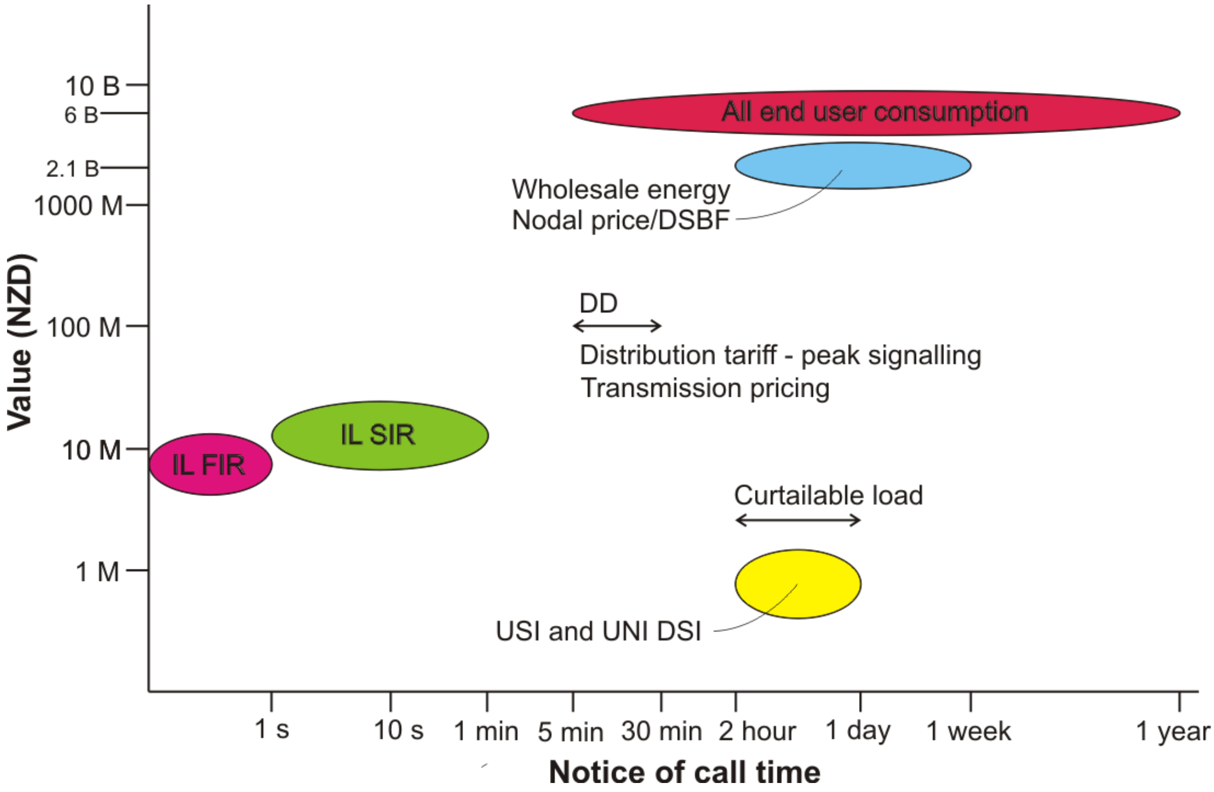

Figure 1 Annual value and speed of response timescales of various forms of DR in NZ. Arrow headed lines denote call time only. IL values correspond to cleared quantities for 2009 and 2010 obtained from Electricity Authority data. USI and UNI DSI values are total call and availability payments made for 2013. Wholesale and all end user values are for 2011 [3].

2. DR at the National Grid Level

2.1 Nodal Pricing

Nodal Pricing in half hourly spot price trading periods is a DR mechanism that operates, to some extent, in the wholesale market. On the supply side, the system relies upon competition amongst generators to moderate prices. On the demand side, purchasers are currently neither dispatched nor receive constrained on or off payments. They observe the final price for the volume they use. Consequently they have an incentive to reduce the nodel spot price if and when they can. Some larger purchasers, and possibly retailers, are known to practice this. However it is ineffective for small to medium consumers, who may not be exposed to the spot price, and have very little load to shift. Even for large purchasers, the signals are very much dependent on the accuracy of prices in the schedules, which are in turn dependent on inputs such as generator offers, non-conforming load bids, and the System Operator's (SO's) load forecast.

2.2 Demand Side Bidding & Forecasting (DSBF)

This Electricity Authority initiative aims to improve the inputs into the price forecast schedules in order to improve the accuracy of the schedules themselves. This in turn allows better use of generation and DR capability [4]. New features to the nodal pricing scheme were implemented with the introduction of DSBF [5]. While load at conforming Grid Exit Points[1] (GXPs) continues to be accurately forecast centrally by the SO, under DSBF, purchasers at conforming GXPs can voluntarily bid price responsive (i.e. elastic) demand as difference bids. Purchasers at non-conforming GXPs prepare nominated bids as previously required. The SO uses this information to publish two schedules called the Price-Responsive Schedule (PRS) and the Non-Response Schedule (NRS). The NRS assumes no demand (i.e. inelastic) response to price. For conforming GXPs, the PRS assumes demand or elastic response to price by including the difference bids [6]. Comparing the two schedules provides information about how price-responsive bids affect the schedules. The schedules are published every half hour covering a rolling 36 hour period. The communication mechanism is the Wholesale Information & Trading System (WITS) [7].

2.3 Dispatchable Demand (DD)

This Electricity Authority initiative is under development and is expected to be operational in May 2014 [8] [9]. It is incentive based DR that will operate in the wholesale market. It is the demand side complement to the supply of dispatchable generation. It will allow large end-users to be dispatched in half hour trading periods in a demand side manner equivalent to generators. Constrained on/off payments[2] will apply as they do for generators. Nominated bids must be submitted for every trading period. Thus it will be possible for nominated bids to be submitted at conforming GXPs by DD purchasers. At any GXP, the purchaser can determine whether a nominated bid is of dispatch or non-dispatch type, whereby the latter bid type turns dispatch off. All nominated dispatch and non-dispatch bids will go into the PRS. All nominated dispatch bids go into the NRS. DD bids are subject to the same 2-hour gate closure provisions of the Code as non-DD bids and generator offers. Participation requires a Dispatch Capable Load Station (DCLS). The communication mechanism is the SO's dispatch tools and WITS [7]. DCLS requirements for a metering installation and to be a dispatchable load purchaser will need to be met [10]. However, potential DD purchasers at non-conforming GXPs are already required to submit bids for every trading period and so there would be little, if any, extra compliance for them under DD. At conforming GXPs this will be a new requirement. It is

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[1] A conforming GXP is one whose load can be accurately forecast by a central forecaster, whereas the load at a non-conforming GXP cannot.

[2] Constrained-on payments compensate a purchaser for being required to purchase electricity at a price above the level its bid indicated it was willing to pay. Constrained-off payments compensate a purchaser for being curtailed when final prices do not justify that curtailment.

possible under DD to aggregate a number of loads into a single DCLS, as long as the aggregated loads are from the same GXP.

2.4 Demand Response Initiatives

For the national grid, the regulatory environment requires Transpower to first seek non-transmission solutions when considering major capital projects, in order for example, to defer building new transmission assets [11]. Transpower has used DR since the 1990's to defer transmission investment [12]. This Transpower grid owner incentive based initiative began as the Upper South Island (USI) DR trial and was followed by the Upper North Island Demand Side Initiative (UNI DSI). It operates out of market. Users who have discretionary demand may participate by reducing their usage when called upon to do so, and receive a call payment for their reduction [13]. Two types are available, the first being *Security DR* whereby the user is compelled to reduce consumption by a contracted amount when called upon to do so. An availability payment is also made. The second type is *Economic* or *Price Responsive DR* in which the user may voluntarily opt in to a call. For both types the call from Transpower is made at least 2.5 hours in advance. Communication is managed via the Demand Response Management System (DRMS) between Transpower and the Curtailment Service Provider (CSP) using Alstom's DRBizNet platform. The CSP may be the consumer or a third party providing service on the consumer's behalf. A Time of Use or Smart Meter is required to log electricity use (e.g. half hourly). Communication via the DRMS to the CSP is by internet via Email or web-browser. Automated web-based computer-to-computer communication is also available.

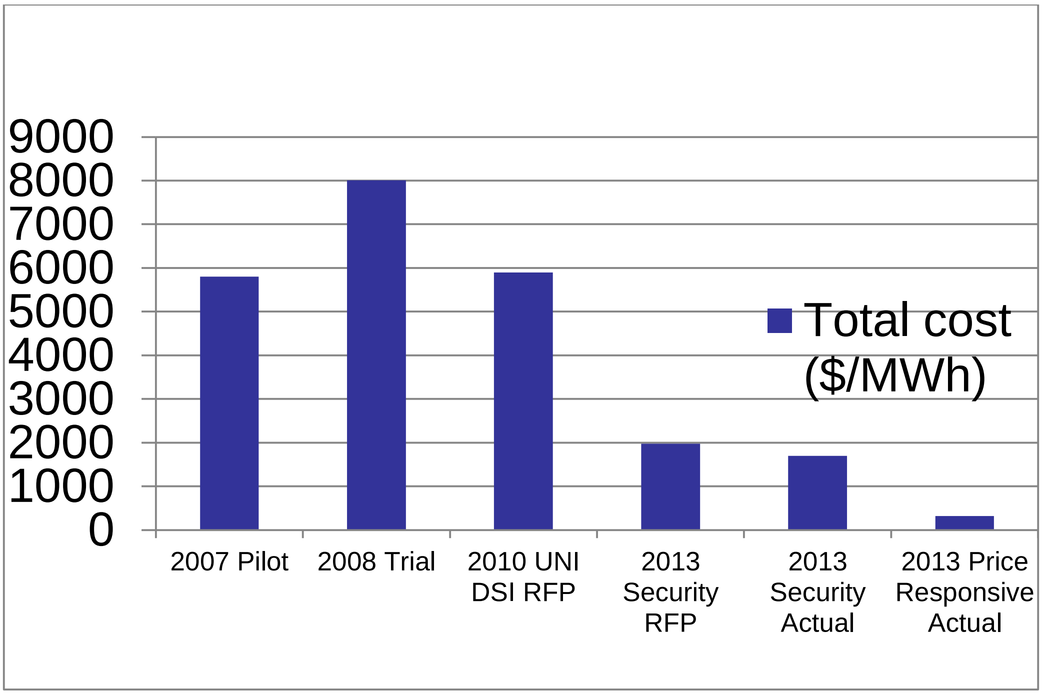

Figure 2 Transpower DR call price history [Source: Transpower NZ Ltd].

In July 2013 Transpower announced that it had received a very positive response [14]. Suppliers varied from commercial businesses, to larger industrials, and to retailers. Over 200 MW was finally obtained representing about 8% of Upper North Island peak demand. Figure 2 shows how the cost of Transpower's DR has fallen substantially. The Price Responsive DR has proven to be the most favourable type in terms of both cost and availability. One third party CSP was involved in the 2013 programme.

In November 2013 the Commerce Commission approved expanding Transpower's DR programme geographically beyond the UNI DSI to the whole of country to enable it to be tested throughout New Zealand [15]. Transpower ultimately has a target of obtaining 10% of peak national demand (6500 MW) through DR [16]. In light of the UNI success, this target appears to be realistic. The next target is small to medium size businesses offering 20 to 200 kW of DR. In the future this may eventually be extended to households, as the DRBizNet platform has this capability. This could occur through the introduction of smart appliances such as fridges, freezers, and thermostats which might link to a smart meter communicating with a CSP.

Transpower may offer its DR platform to other companies for their own purposes.

2.5 Interruptible Load (IL)

IL is incentive based DR. It is an ancillary service and one of two forms of Instantaneous Reserve (IR), the other form being Spinning Reserve (SR). IL is load available for shedding or demand reduction, whereas SR is additional generation capacity that can be made quickly available. IR of both forms enables the power system to respond to the tripping of the largest single supply asset, which is known as the risk setter, by supporting the grid system frequency to avoid cascade failure [17]. IR is further categorised into two classes based on time and duration of response: the first being Fast IR (FIR) which arrests frequency fall; and the second being Sustained IR (SIR) which restores frequency. IL that qualifies as FIR must be capable of being shed within 1 second of the grid system frequency falling to or below 49.2 Hz and be sustained for at least 60 seconds [18]. IL that qualifies as SIR must be shed over the first 60 seconds of the grid system frequency falling to or below 49.2 Hz and be sustained until instructed by the SO [18]. IL is shed automatically using frequency controlled relays. Figure 3 presents an example of IL shedding. The quantity of FIR required on hand is calculated by the SO's Reserve Management Tool (RMT). The required quantities of IR are procured by the SO in an IR reserves market using the same procurement system as the wholesale energy market. IR, including IL, is offered and co-optimized by SPD with the energy market. A separate market exists for IR for each of the North and South Islands. The cost of procurement for the IR market is carried by the generators and the HVDC link owner (Transpower Ltd) who create the risk and the need for IR. Availability and event payments are charged. An event charge is paid by who is responsible for causing the under frequency event. The event charge is rebated to those who pay availability charges. On the demand side, IL is provided by industrial and commercial end-users. Usually these end-users will provide their IL via an aggregator who is contracted by the SO to offer IL into the reserves market. In return, the end-users receive payments for their IL.

The cost of procuring IR in the reserves market was $66.2 million in 2009 and $21.9 million in 2010 [19]. Variation in this cost in recent years has been the result of factors such as energy market prices and the level of HVDC link transfers [17]. In comparison, the wholesale energy market traded $2.1 billion worth of energy in the year to July 2011 [3]. In monetary terms, the IR market therefore represents at most only about 3% of the energy market but it is essential for covering the security risk associated with the supply of energy.

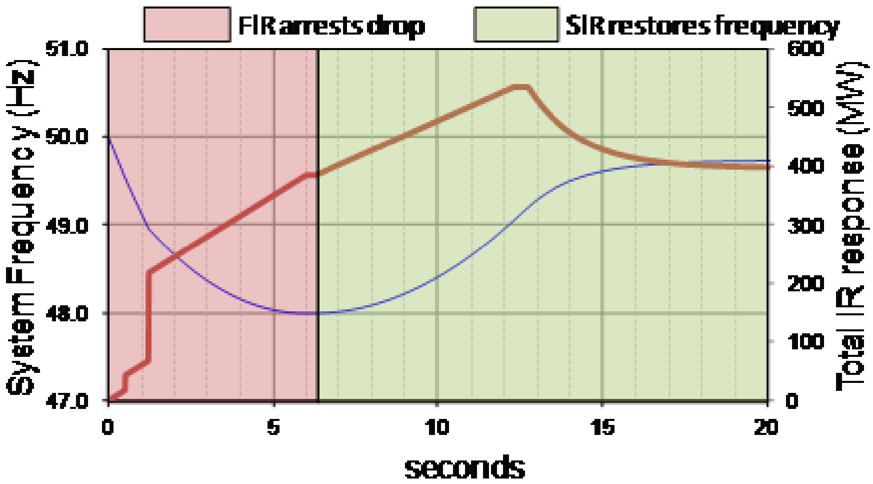

Figure 3 Example of IR activation: Step changes in capacity response is IL dropping off, gradual change is in response to spinning reserve changing output [Source: Electricity Authority].

2.5.1 EnerNOC's Ancillary Services Programme

EnerNOC Inc. is an aggregator of IL under its DemandSMART NZ Interruptible Load Programme [20]. In 2012 this offered over 120 MW of IL to the IR market in the North Island. It procures IL in both North and South Islands for Genesis Energy [21]. EnerNOC installs a data server at the client's facility enabling real-time monitoring and viewing of energy data. Upon detecting a frequency drop EnerNOC metering automatically initiates shedding of nominated load which is notified to the client via SMS or Email. Clients receive monthly payments [22].

2.6 Scarcity Pricing

This Electricity Authority wholesale market initiative came into force on 1 June 2013. It provides for the introduction of a $10,000/MWh price floor and $20,000/MWh price cap to the spot market when an electricity supply emergency throughout one or both islands causes forced power cuts i.e. emergency load shedding [23]. The initiative addresses the scenario whereby forced load shedding curtails demand whilst last resort generation is attempting to increase supply resulting in spot prices falling rather than rising.

3. DR at the Retailer

The general views of a selection of major retailers who have been interviewed are described in this section.

3.1 Direct Load Control

DR is used by retailers to manage load and therefore influence spot prices in an area, particularly if that area is constrained. A retailer may contract with distributors to use ripple control to provide load shifting services for peak periods. This can also include locational load shifting between GXPs. System agreements between a retailer and distributor may allow load controlling for the retailer's purposes if the distributor is not requiring control for security of its own network. This control affects the customer loads of multiple retailers. The interests of these retailers are usually aligned by load controlling, the exception being a generator benefitting from a constraint. A more granular approach available is to load control through specific ripple channels. Ultimately, Advanced Metering Infrastructure (AMI) will allow a retailer to just control the load of its own customers.

3.2 Procurement of IL

However, in general a greater priority is placed on the procurement of IL. The spot energy price is influenced by the availability of reserve since the two are co-optimized. Generation plant, or HVDC transmission, may be constrained back by a lack of reserve (the need albeit reduced with the commissioning of the second HVDC Pole 3). Thus the provision of IL can help mitigate high prices on a retailer's load, as the spot energy price is influenced by the availability of reserve. Furthermore, from the perspective of a generator, sufficient reserve ensures dispatch enabling revenue from generation. The revenue which the retailer receives from the IL service itself is not a major consideration.

For example, reserve in the receiving island can facilitate transfer on the HVDC link and thereby reduce prices. This creates an incentive for generator-retailers (gen-tailers) to contract for IL. It is conceivable that a generator may also purchase reserve in the South Island in order to manage southward HVDC power flows, and thereby manage their reservoirs more effectively. This does depend on the generation mix of the generation company, so the focus on reserve and therefore IL may depend on the company.

Overall however, markets such as the spot energy market, the hedging market (ASX), and the Financial Transmission Rights (FTRs) used to manage basis risk (the change in price between locations where one buys and sells) are of far more value to gen-tailers. It might be argued that gen-tailers are not concerned about price because of their internal hedge as both generator and buyer, and because of hedging used by the rest. However, price is in fact, a major concern to them. Even if their exposure is just 20% of the market, pricing going high (e.g. above $200/MWh) may be severely detrimental to them. Such a situation may arise where the high spot price is due to a constraint in an area in which the retailer is supplying customers, but where the gen-tailer is not itself generating.

3.3 Curtailable Load

Out of market curtailable load is being used to manage basis risk for a retailer. Curtailable industrial and commercial load in the lower North Island is being aggregated by EnerNOC, in this instance for Genesis Energy [24]. This aims to reduce wholesale electricity price spikes in the lower North Island. When the need arises, Genesis informs EnerNOC that DR capacity is required. In turn EnerNOC contacts their clients to reduce consumption or switch to back-up generation. The notice time is two hours and clients have the choice to opt out in a manner similar to Transpower's price responsive DR. EnerNOC installs meters that communicate to its Network Operations Centre. Clients then have real time energy monitoring via EnerNOC's DemandSMART web based portal. Notification to clients is via SMS, Email, or phone. Clients receive a capacity payment for being enrolled and an energy payment based on the amount of DR delivered.

Retailers may also directly contract embedded generators to mitigate high spot prices during a transmission constraint.

3.4 Tariff based DR

This is price based DR and it requires the roll-out of AMI or smart meters to consumers. In [12] it is noted that New Zealand still lags the US in the introduction of price based DR, and that significant investments are required in communications, smart-meters, and smart appliances before a significant impact can be made. A retailer who has introduced smart-meters and Time of Use (TOU) tariffs to domestic consumers comments that their roll-out process is slow but on-going.

3.5 DD and DSBF

One retailer views the forthcoming introduction of DD with some appeal. In contrast, it views DSBF as having very little appeal; it seems difficult to imagine a situation where sustained DR is provided voluntarily by DSBF when the prices are high for a sustained period of months at a time. DSBF can adjust bids, so it will probably adjust them up, thereby making it only useful for brief periods if at all. The voluntary nature of DSBF also makes it unreliable.

Another retailer notes that a DD participant is required to be a purchaser as defined by the Code, and that except for very large users, compliance issues will require the need for an aggregator. Regarding DSBF, this retailer argues that as consumers do not respond in the wholesale market timeframe, and as larger users use hedging, that there is insufficient response for DSBF. However, the retailer suggests that sufficient smart-metering signalling spot pricing may enable enough response.

4. DR at the Distribution Level

Ripple control to shed household hot water heating load has been used for many decades in New Zealand [25] [26] to very successfully improve the utilisation of generation, transmission, and distribution assets. It is a form of incentive based DR known as Direct Load Control (DLC) [2]. Today it remains the principal DR tool used by distributors. Transpower charges distribution companies for the use of the national grid by including a Regional Coincident Peak Demand (RCPD) charge [27]. There are two regions in each island. Both upper island regions (UNI and USI) price on the 12 RCPD peaks in the measurement period, while the two lower island regions price on the top 100 RCPD peaks. A distribution company responds by using ripple control to minimize their portion of their region's charge. In this Section, more unusual or innovative forms of DR implemented by several distribution companies are out-lined beginning with an overview of Orion's DR.

4.1 Orion

Orion uses DR for the purposes of deferring capital expenditure, and maintaining compliance with their security of supply standard. The use of DR was an important tool in managing the restoration of supply during the 2010-2011 Canterbury earthquakes. Metering owners have installed approximately 110,000 smart meters, most of which contain inbuilt ripple receivers on the Orion network. Where appropriate, the remainder of the 190,000 network connections have standalone ripple receivers.

The use of ripple control allows a 5-10% reduction of peak demand corresponding to 30-60 MW. Customers with loads exceeding 300 kVA are subject to peak demand period pricing. This enables a further 3% of peak demand reduction. Furthermore, it is estimated that the use of day-night pricing options has encouraged approximately 10% of load to be shifted from the daytime peak into the overnight trough[3]. Thus peak demand has been reduced by a total of approximately 20% and this is responsible for a large part of the divergence between energy and peak demand shown in Figure 4.

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[3] Approximately 50,000 connections are on day/night and a further 10,000 or so on separate night rates. The transfer of load to the night is so successful that the signalling of night load switching is staggered to manage potential night time peaks.

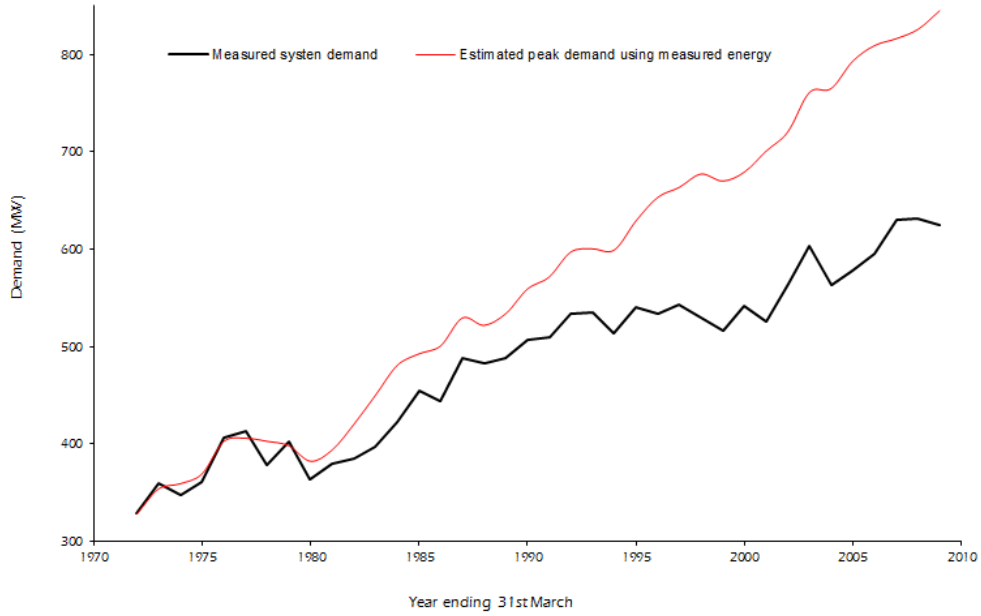

Figure 4 Historical growth of Orion network's peak demand. Black line: measured system peak demand. Red line: system peak demand if it had grown at the same rate as demand in energy [Source: Orion NZ Ltd].

Figure 5 shows how ripple control reduces peak demand in the USI region on a winter day by levelling out peaks to fill adjacent troughs. At a regional level Orion has achieved all the load shifting that is practical short of using other storage means to shift day-time consumption into the night.

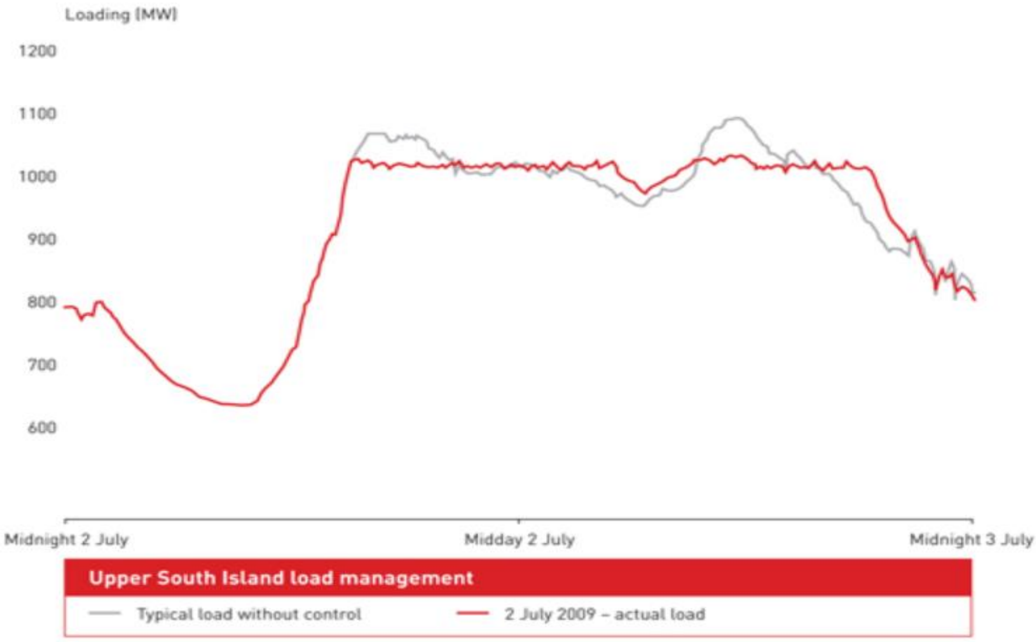

Figure 5 An example of ripple control to contain the USI's Winter day peak demand [Source: Orion NZ Ltd].

Orion has led the implementation of the USI Load Manager, starting with the 2009-2011 trial [28] which began co-ordinating the ripple loads of eight distribution companies. Out of 1000 MW of USI load, there is 70 to 100 MW of manageable load. This regional DR load managing initiative also provides Transpower with greater visibility via the USI Load Manager of the state of the USI demand side response and enables transmission investment deferral.

Orion has established a load curtailment scheme to better manage a peculiar combination of two characteristics of its rural network: the first being long distribution lines having low inter-connectivity; and the second being large water-pump loads being feed from these lines during the irrigation season. The scheme provides irrigators with the option of being contracted to be the first to be cut-off in an emergency, thereby allowing better security of supply for more critical loads such as dairy sheds in an affected area. This DR scheme uses ripple control to operate only irrigator relays. Irrigators are incentivised to participate with an interruptibility rebate [29]. The scheme has enabled substantial deferral of rural network investment in lines and contingency assets.

4.2 The Lines Company (TLC)

In response to having a network characterized by low demand and connection densities having many remote rural connections, combined with a high proportion of customers with low annual energy consumption, TLC has moved to charging for capacity [30]. An energy based charging methodology was deemed unsuitable. Instead, TLC has introduced a charging component based on the uncontrolled kW load of a customer during periods of load controlling. To better facilitate this approach, TLC is gradually rolling out its own advanced metering. For customers with this metering, the six highest two hour peaks in the measurement period when TLC is load controlling are averaged to determine a base variable capacity and associated charge. TLC have also introduced direct billing of line charges to consumers, and considers this approach more effective than using traditional retailer channels. The resulting separation of billing of line charges and of retailer energy charges should provide greater transparency of electricity pricing for consumers. TLC has an ageing network. The DR resulting from capacity pricing should also allow TLC to focus on renewing ageing assets to enhance security rather than having to use resources to increase network capacity.

4.3 Vector

Vector has launched an initiative offering installation of Photo-Voltaic (PV) panels combined with battery storage for domestic customers [31]. The installation includes a 12.3 kWh Lithium ion battery pack, inverter, and control unit with a choice of 3, 4, or 5 kW capacity PV panels. In [32] the potential problems of increasing PV only penetration into the network are described such as over/under-voltage and un-intended islanding. The addition of battery storage mitigates these issues. Further, the addition of battery storage enhances the benefits of PV which include: supply security, power quality management, mitigating the potential charging impact of electric vehicles on the network, and operation as a peak power supply. Distributed battery storage allows batteries to be charged at night, and then be used by the distributor to load shift power back into the network at peak times. Figure 6 provides a simulated example of how the addition of storage to PV allows peak demand from a network to be curtailed in the evening when PV supply is unavailable.

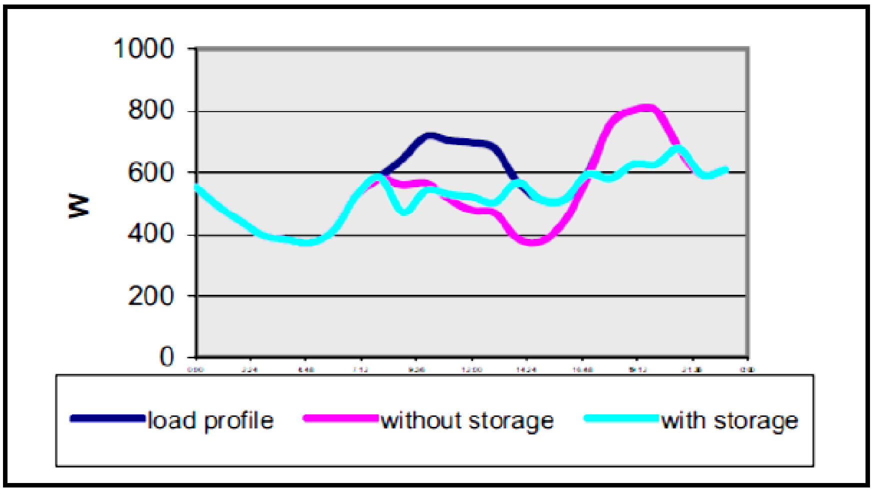

Figure 6 Simulated load profile of an urban LV network during normal operation, with 10% PV penetration and with PV and storage [32].

5. DR for Domestic Consumers

Historically, DR operating in the NZ home has been limited to distributor's ripple control of hot-water and the homeowner's manual response to the retailer's traditional tariffs such as day/night rates. However this is slowly beginning to become more sophisticated following the introduction of Home Energy Management Systems (HEMS) in the US since 2008-2009. HEMS is defined by [33] as any product or service that monitors, controls, or analyzes energy in the home. This definition not only includes smart-meters, but also residential utility DR programs, home automation services, data analysis and visualization, auditing, and related security services. HEMS solutions can be classified as utility based or non-utility based. In the US, utility solutions typically involve a single-load-per-home DR program or an energy efficiency initiative. DR systems' costs are in the low-to-mid hundreds of dollars range, and baseload reduction/energy efficiency programs save 2 percent to 20 percent. Utilities typically do a one-time hardware purchase with an annual subscription service for energy management and integration services provided by the vendor. The utility benefits greatly from these services, and usually also has to pay for the entire solution. Comparatively, NZ's use of ripple control is already wide-spread and provides a substantial benefit.

Non-utility solutions in the US focus solely on the home customer and integrate various smart-home services, which fall under the broad definition of HEMS proposed above. The detailed economic analysis used for utility customers is replaced with a smart marketing campaign targeting the needs of homeowners. Vendors often enter the home with a security solution and then offer HEMS as an add-on sale. Homeowners can purchase the HEMS hardware in the mid-hundreds to low-thousands range, and pay between \$15 and \$60 per month for energy management, automation and security services. Between \$5 and \$15 of this monthly bill can be attributed to energy management services. This business model can effectively double telecom company revenue for a home and is easy to scale to millions of existing customers.

Overlapping solutions consist mainly of smart thermostats. The US HEMS sector is described by [33] as being no longer about complex hardware solutions focused solely on maximizing energy reduction in the home while ignoring occupant comfort. Instead, utilities, customers and third-party vendors look to find the right balance between energy reduction, cost and customer satisfaction.

In [34], the technical components of a HEMS system are listed as comprising of sensing devices, measuring devices, smart appliances, enabling ICT, and energy management systems. Challenges to implementation are summarized as cost, lack of standards, low consumer awareness or interest, choice of ICT, and degree of system intelligence. In [35] HEMS is investigated in detail, and in [36] ICT systems for the smart-grid and home are examined. The difficulty in vendors successfully launching HEMS is highlighted by giants Google, Microsoft, and Cisco all withdrawing certain energy management products in recent years [34].

With reference to Section 4, some examples of HEMS being employed in NZ include TLC's tools for peak load management and Vector's PV and battery system including the control unit and an online dashboard. TLC offers a power viewing device and a smart-switch which automatically turns off appliances connected to it during load controlling [37].

6. Discussion and Further Directions for DR

The aim of DSBF described in Section 2.2 is to improve the inputs into the price forecast schedules in order to improve the accuracy of the schedules themselves. The resulting benefit of more accurate schedules is better use and planning of generation and DR capability. It is suggested that the schedules could be made more efficient by the following actions: first, by applying better methodology to further improve the accuracy of the load forecasts; secondly by improving the accuracy of non-conforming load bids, and thirdly by reducing the gate closure time to less than two hours. Currently, bids and offers may only be revised up to two hours in advance of their trading period unless there are exceptional circumstances [38]. Reducing the closure time may require more rapid SPD processing.

The system frequency continuously fluctuates in response to changing demand and the impossibility of generation being able to instantaneously track that demand. Frequency keeping generators are contracted in the ancillary services market to maintain system frequency fluctuation to within a normal band [39]. With increasing penetration of intermittent renewable generation in NZ such as wind, in order to maintain balancing, the amount and cost of frequency keeping may increase in the future. A possible alternative to more backup generation is a demand side solution known as Dynamic Demand Control (DDC). This involves using frequency responsive loads which may be industrial, commercial, or domestic. Suitable loads include refrigerators, freezers, air conditioners, and heating systems. A simulation applying DDC using domestic refrigerator loads in the UK suggested technical and economic benefits [40].

The wholesale market is currently reliant on dispatchable generators competing amongst themselves, without dispatchable demand side bidders. DD changes that, and presents the potential to aggregate load suitable for DD (from the same GXP) at a single DCLS. This could reduce compliance cost encouraging DD participation beyond large users. There is also the potential for an aggregator to use a platform for DD such as Transpower's DRMS.

7. Conclusions

Many forms of DR, both incentive and price based, have been identified operating at all levels of the electricity complex in NZ from the SO through to the domestic consumer. These realise the benefits of DR including deferred asset investment, reduced environmental impact, improved security of supply, and better integration of variable renewable generation. Further forms of DR and their associated systems will be adopted as smart-grid and smart-technologies develop, altogether forming a rapidly emerging fabric of DR systems in NZ.

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