Foundation for Effective Markets and Governance

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Dr John Tamblyn
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Dear John

Demand Side Participation in the NEM

Draft report

"Markets require both a supply and a demand side to function effectively. The demand side of the market is severely under-developed."

PJM Market Monitoring Unit, 2004 State of the Market

Attached is a response to Draft Report on Demand Side Participation in the NEM which I have prepared on behalf of the above organisations. It takes the form of introductory remarks and conclusions followed by some detailed observations on recommendations in the draft report.

Introductory remarks

The Australian Energy Market Commission (AEMC) is to be commended for its initiative and for raising the profile of this issue in the context of the Australian electricity market. The purpose of this paper is to set out some reactions on the contents, the stage the debate has reached and to try and draw some parallels and lessons from similar debates in other places. We do this in this covering letter. In the attachment we set out some more detailed comments on the AEMC's draft conclusions. An annex to the attachment sets out some notes on British experience of energy schemes (not networks), and a further one gives some references and further reading focussing on policy development and practice in other markets, particularly Britain.

The draft report sets out a broad range of aspects of demand-side interaction with the NEM, with the view of ensuring market rules do not create unnecessary barriers to such participation in the market, in particular by identifying areas of potential bias that could lead to "unnecessary weight on expanding generation and network capacity". In this context it is helpful to note that the demand-side is not simply an economic concept;

rather it is short-hand for the generality of consumers who pay for generation and the bulk of the costs of networks.

There is abundant literature on the role of the demand-side and how it manifests itself through electricity markets around the world. A common flaw in much of the literature is the way in which the issue tends to be addressed in an abstract way, without reference to clearly defined mechanisms––including their costs––and how they can be designed, implemented and improved with a view to maximising the consumer benefit. The report constitutes a thorough and wide-ranging critique of current practices at work in Australia and how they might be enhanced. It demonstrates the various ways in which consumers are impacted if not engaged appropriately.

Value of demand-side

Demand response is where actual load reduction occurs to accommodate high market prices or in response to tight or emergency market conditions. Many participants see such circumstances as opportunities to create extra revenues (generation) or to avoid additional costs (networks). The test should be how to maximise consumer benefits as an end in itself and how to genuinely improve energy service provision from the end user's perspective.

An important factor is the need to match supply and demand instantaneously on the electricity system, but this can be effected by taking demand off the system as well as putting new supply onto it in situations where price signals or clear instructions can be fed through to customers. However, because electricity cannot be stored, this makes demand-side participation more difficult compared to other traditional commodity markets. But in the right setting the two can compete fairly, and these characteristics also increase the value of flexible demand and its interruption. Where demand response is systematic, it can also help defer network investment.

In short controllable demand can increase competition in the wider market as well as providing a valuable resource to network and system operators, and where supported by the right market and network rules invariably delivers real benefits to consumers. Against this, the reality is that market rules tend to be stacked against realisation of this outcome because of entrenched systems for energy delivery devised by engineers and of a lack of properly targeted incentives to tilt the balance in the opposite direction.

Thus the debate should be about encouraging flexibility in the use of electricity by consumers. The demand-side should be encouraged––probably incentivised––to become involved in the processes of setting prices and maintaining the quality of supply, and hence provide a counter to the otherwise dominant role of the generators. It should be a price setter not a distressed price taker. Consumers should see opportunities to gain a financial reward, via a direct payment for the electricity they did not consume at an agreed time, or a reduced tariff or participation payment. Consumers may also benefit through improved energy efficiency and service delivery, and the benefits of these should be clearly quantified and taken into account by policy makers and regulators but also by industry managers in the investment decisions they make.

Demand-side participation can take a number of forms at both wholesale and retail levels, as the AEMC draft report illustrates, but we do not consider that it explores these adequately from the consumer's perspective.

Wholesale market barriers

Demand-side bidding (DSB) is seen as an important component in ensuring that competitive electricity markets behave in an efficient manner. Demand is not fully integrated into wholesale markets in Australia, and the goal should be full parity. In practical terms this means the economic effect of any action affecting the cost of electricity should be transparent and available for capture by any wholesale market participant, including large users. However under current market structures, generation, transmission, and demand do not all have the same opportunity to capture this value.

Market efficiency and low electricity prices are important to all consumers, but the workings of electricity markets are usually far removed from their usual business activities. Consequently demand-side bidding is usually seen as an unwanted distraction or a luxury for the few who can assimilate complex market rules and negotiate on a par with other industry players. AEMC suggests the current rules and costs are proportionate, but it would be helpful to see clearer justification for this assertion.

Because of the inherent complexity, the role of the aggregator or consolidator (agents) is crucial in providing the necessary impetus to make DS activity happen. The agent may be an independent service provider or a conventional retailer. In either case, they bring together knowledge of electricity markets, an understanding of the processes of the end consumers of electricity, and the expertise to implement the necessary control, monitoring and communications technologies needed to implement the necessary programmes.

Regulatory and market rules should be designed to encourage such activity. The potential benefits extend well beyond the customer to market competitiveness, enhanced security of supply and more efficient usage leading to more benign environmental impacts. Policy makers should be contemplating measures that actively support demand-side activity at least until inherent barriers are removed.

In fact many successful applications of DSB to date around the world seem to have been used to cope with abnormal or unusual situations––they are reliability based. This is illustrated by RTO programmes in the United States, which emerged with regulatory encouragement following the localised power crises in the early part of the decade. Many of the successful "planned balancing" examples implemented in Scandinavia have tended to be in generation limited networks, where peak demands are reduced for just a few hours per year. A similar scenario exists in network constrained regions where the transmission system is stretched to its full capacity for only a few hours per year. This tendency is apparent in Australia with the focus in the past on NEMMCo's market intervention powers.

Perhaps because of this bias, a further observation on the report is that there is no in-depth discussion of how agents and intermediaries might be better positioned to help explore and develop wider market-based opportunities that are price-based. This is probably because Australia does not have an organised day-ahead market, which raises the key point that different market structures can greatly facilitate better demand-side engagement. With the two-settlement arrangements commonplace in North America, retailers and consumers can fix their position in the organised day-ahead market and sell back their position in real time. This is an issue worth exploring. The AEMC should respond to this point in the final report.

A market does not necessarily need this two-settlement structure as a pre-condition of greater demand-side participation as is evidenced by Britain. Here utilities in their role as supplier, aggregate flexible loads and act as an intermediary in effect with the reserve trader. The market rules can help or hinder such outcomes.

It is highly likely that new opportunities for DSP will emerge as cost reduction continues with regard to control, monitoring and communications technologies, eventually including smaller consumers as part of 'customer services' packages provided by agents. But recognised barriers that have been well-documented (for instance by the work carried out by Brattle for the AEMC) must be aggressively tackled by regulators and market operators first if this is to happen.

Retail market barriers and opportunities

Demand-side mechanisms and programmes tend to be a feature of wholesale markets, although the scope for demand-side participation also applies at the retail level. Consumers properly enabled can reschedule their electricity use to follow price signals on a daily, or even hourly, basis.

To date, Australian markets have been characterised by relatively stable prices and predictable supply curves. Notable exceptions have occurred in the last few years which have been associated with particular events. Extremes in temperature all multiple systems failures have led to strongly adverse price or demand spikes. The changing composition of generation implied by the government's greenhouse gas emissions reduction strategy suggests that supply variability may become a much greater element of the market. In some networks, particularly where there is a high component of dependable and controllable hydro electricity, this is unlikely ever to become important, as witnessed by the very flat spot prices for most of the year in countries such as Sweden and Norway. However, in other markets, within day variations in electricity prices are common, and end consumers who have the flexibility to respond to price signals, could become very important to suppliers wishing to minimise their overall costs. The greater use of non-firm generation (wind, solar) could make this demand-side flexibility significantly more important into the future.

The actual response can take a number of forms. For example it could be businesses ceasing or reducing industrial processes, or in markets where time of day prices signals are available to households it could be remote appliance switching or a consumer's own actions (such as using appliances at a different time of day, i.e. load shifting) to respond to higher prices. For larger retail consumers it can also be delivered under balancing contracts usually with the system operator to assist it in balancing often in short operating timescales (frequency response, fast reserves).

Three particular problems tend to dominate at the retail level across markets:

- lack of retail dynamic pricing
- absence of enabling technology
- limited awareness of programmes and benefits.

The AEMC work seems very light in this area. Given the likely growth of intermittent energy sources such as wind and solar as well as small-scale domestic generation these themes should be further developed.

Conclusion

The AEMC's review of demand-side participation in the NEM is to be welcomed. In many ways the thinking is in advance of that seen in many liberalised markets (for example the consideration of the interaction with price controls), and references to the many potential ways that market rules and network regulation can impact on the scope for demand-side participation.

The prevailing market settings are a key determinant of whether demand response materialises, to what extent and in what form. Further, regulatory incentives can also be a driving factor, especially on the readiness of network operators to enter commercial arrangements with demand-side participants. The draft report addresses both these interactions but only from the perspective of not creating unnecessary barriers rather than facilitating increased demand-side engagement.

Our main criticism and is one that is shared across many markets is that consumer engagement is seen as a residual part of the process, and the process is dominated by considerations of how to achieve more efficient investment and operating cost reductions. Important though these are, demand side participation should also be pursued as a legitimate end in itself.

Experiences in Britain and other overseas markets show that the various barriers many of which are identified in an Australian context can prove enduring and that specific measures should be considered to incentivise or stimulate greater demand-side participation. The debate would benefit from the systematic involvement of those most directly impacted by it, that is consumers and their representatives.

Yours sincerely

Allan

Allan Asher
Director, FEMAG

Specific comments on findings

Key findings and commentary:

1. That the basic model of price cap regulation provides regulated network businesses with financial incentives that are consistent with efficient use of demand side. It said that a profit maximising price-capped network business has commercial incentives to offer DSP inducement payments up to the difference between the network charge and the peak demand capacity costs avoided by the DSP. It said that if price caps can provide appropriate incentives for a network to buy efficient amount of DSP, then the imposition of supplementary DSP incentive mechanisms will not be required to improve the efficiency.

   It concluded that revenue cap regulation has weaker incentives but it did not consider the weaker incentive –which appeared to create incentives on networks to use too much DSP (p17) - are material barriers given other mitigating features of the regulatory framework (which requires more active assessment of pricing methodologies) and also having regard to the wider reasons for adopting a revenue cap as a form of control.

   Its argument is in the context that there are practical limitations on how accurate the cost reflective charging signals given by the networks can be (particularly in the absence of time-of-use charges). This lack of precision means there is potential for bilateral contracts between users and network businesses to improve the overall efficiency of consumption. AEMC noted the work undertaken on commitments to roll-out or further consider roll-out of interval meters (p14).

   Comment - Although networks currently operate under a mix of price caps (distributers) and revenue caps (transmitters) in GB, the overall RPI-X regulatory framework is currently being examined in the Ofgem led "RPI-X at 20 review" (see ref 3 below).This is currently in the "visionary" stage where the objective is to understand all the issues affecting energy networks and network regulation, including how the demand side can be better integrated.

   The government published the different options for the national roll-out of smart meters and indicated its preferred way forward on 11 May 2009 (see ref 4 below.) A supplier-led route is being proposed, though the government is currently considering how it might usefully involve the distribution businesses.

   There has been little debate on the structure of different price control approaches in Britain, though from a theoretical perspective the AEMC comments are correct. In practice the limited consideration of demand-side incentives in Britain has focussed on specific incentives such as the distributed generation incentive, Regional Power Zones and the Innovation Funding Incentive. Further detail can be provided if needed.

2. AEMC found that the current method for re-setting network prices or revenue allowances appears to penalise a business which in the previous regulatory period decided to use expenditure on DSP as a means of deferring capital expenditure. It found that there is an imbalance in the risk of recovering revenue between capital and operating expenditure creates a bias against expenditure on DSP. This is because the current regulatory framework exposes network businesses to the risk of over-spending on capital expenditure until the next regulatory reset, but there is no "automatic" regulatory future revenue allowance of a network business makes an ongoing commitment to incur operational expenditure (p25). It has suggested options to address the issue, including providing exemptions from the "efficiency carryover mechanism" (ECM) which provides a constant retention period for cost savings or over-runs. This would means that the cost of DSP expenditure would not be included in the calculation of ECM and therefore not carry over into subsequent regulatory periods. Another option is requiring a capital expenditure ECM. It said that if designed appropriately this would mean that gains and benefits would be symmetrical between capital and operating expenditure;

   Comment - The issue of imbalances between incentives for different types of cost is being considered as part of DPCR5, (see ref 2 below, 9.1-9.19). DNOs currently bear the full cost of each additional £1 classified as opex but only 29p to 40p for each additional £1 that is capitalised. Ofgem said that the balance of incentives is particularly important in the context of large increases in forecast costs, and it is looking to ensure that DNOs have given consideration to innovative solutions including potentially deferring greater volumes of work and doing more to actively manage and monitor levels of risk. Given the climate change agenda, it said it was important not to reduce the incentive on DNOs to adopt non-network solutions such as demand side management or contracting with distributed generation to manage constraints. It is currently proposing an approach which will treat all network investment, network operating costs and closely associated indirect costs in the same way by capitalising a fixed percentage of costs across all these activities into the Regulatory Asset Value (i.e. extending the approach currently applied only to capex).

3. The limited financial incentives for network businesses to innovate under the current forms of revenue regulation are likely to act as a barrier to the businesses making appropriate use of DSP. AEMC said that a possible option to address this would be to provide an allowance for network owners to recover expenditure for approved innovation projects outside the standard expenditure requirements. This would place a limit on the funds available and limit the use of any funding to accredited projects. The rationale is that the process of resetting allowed revenues periodically may affect the perceived benefits of innovation. Future revenues may be adjusted downwards at the next price review to reflect the cost savings, so the flow of profits is limited to five years, whereas the costs may require a longer pay-back period. AEMC considered that the incentives for internal self funding of innovation appear to guide the businesses towards conservatism, which might be exacerbated by the potentially large fixed costs of establishing research and innovation capability in the first instance and the associated required changes in organisational culture to make it work effectively.

Comment - In the December policy paper for DPCR5 (see ref 1below 2.61-2.75) Ofgem set out three possible options for a new incentive to encourage innovation. It said that neither the equalisation of opex/capex expenditure or the existing Registered Power Zones and Innovation Funding Incentive were enough to overcome the "low risk business as usual" ethos of the DNOs. It is considering three options, one providing ex ante funding for specific proposals, project by project funding through the price control period, or an ex post assessment of outcomes where the regulator would provide a significant discretionary reward to DNOs who had successfully improved network flexibility or implemented innovative solutions.

The report also makes findings in the following areas:

4. Network planning standards

AEMC found

- that probabilistic planning standards are likely to be more consistent with efficient use of DSP because the appear more amenable to handling DSP with different degrees of "firmness";
- **Comment – many systems operate on the basis of deterministic standards leading to higher levels of generation cover. It is not clear what AEMC propose to do about it.**
- difficulties caused by variability in network planning and consultation processes across the networks. It said that efficient DSP is likely to involve aggregation of individual loads by specialist intermediaries and unnecessary variations in approach are likely to increase the costs of such businesses operating across the national market.
- **Comment – clearly common standards will help reduce distortions to take up all other things being equal.**

5. Network connection

- the report highlights the significance of small scale on-site generation as a contribution to DSP. It said that existing processes by which small scale generation can be connected or recognised by the distribution networks currently lack consistency and transparency.
- **Comment – there is a tendency for SOs to prefer critical mass. This means they tend to apply thresholds that exclude all but larger consumers or rely on regulators to bring this load to the market. As for the distributors, in Britain there is little consistency between DNOs and no obvious sign that there is a development path for achieving one.**

6. Wholesale market participation

- It found that there were significant costs associated with being a direct market participant but concluded that on the whole these costs were reasonable and proportionate. It found that it was simpler and more efficient for DSP to access the wholesale market indirectly by contracting bilaterally or by trading financial contracts.
- **Comment – this is a common characteristic, especially as SOs tend to guarantee revenues through availability payments. But surely the challenge**

should be to enable larger consumers that wish to to participate directly. How might compliance requirements and costs be mitigated for users?

7. Reliability

- The review considered the short-term management of reliability by NEMMCO, where it can intervene in cases of insufficient capacity to buy additional capacity or issue directions to existing market participants. AEMC found that these measures are opportunities rather than barriers for DSPs but found one material barrier in the inability of NEMMCO to compensate "unscheduled" loads even if they are capable of being directed.
- **Comment – a higher take up of demand-side options should help pre-empt the need for short-term emergency actions and directions by the SO.**

Annex A

Demand-side participation in Britain's energy market

1990-2001

Following privatisation of the electricity market and up until 2001 power was traded in a day-ahead Pool after which the transmission system operator took control of the system and could adjust the accepted Pool offers and use ancillary service contracts to achieve a balanced system. Demand-side bidding into the Pool was introduced from the end of 1993. Bidders were obliged to offer a minimum of 10 MW of demand reduction in any half-hourly settlement period and 50GWh of demand reduction over the course of a year. The bid had to specify the price at which they were prepared to reduce their demand (the same price curve for all 48 settlement periods in a day) and the level of demand reduction they could deliver in each settlement period. Bidders were not paid for any energy they were scheduled not to consume but they did receive an availability payment when they were available to reduce demand but not scheduled to do so.

2001 – present

The new electricity trading arrangements (NETA) introduced a single settlement system in 2001. Bilateral trading (over the counter or via power exchanges) continues until an hour before the start of each settlement period when the balancing mechanism real-time market opens.

The balancing mechanism was specifically designed to enable demand side bidding. Bidders must provide information on their intended level of consumption during the settlement period and the price and extent to which they are prepared to move away from this level. If their offer is accepted, i.e., they are requested to reduce their demand, they are paid their offer price for the energy they do not consume although bidders are exposed to imbalance charges for any difference between the demand they notify to the settlement administrator when the real time market opens and the volume of contracts they have signed to cover that demand.

<u>Ancillary balancing services</u>

In addition the transmission system operator offers a number of different ancillary services.

Service	Demand side involvement (MW)	Demand involvement in 2005/06	
		% of service provided	% of total demand
Short term operating reserve - firm	1800-2000 MW	32%	>1%
Short term operating reserve - flexible	250-400 MW		
Fast reserve	Possible, but volume unknown	6%	<1%
Frequency response	450 MW	36%	~1%
Constraint management	Possible, but none so far	Possible, but none so far	N.A.

<u>Short term operating reserve</u> (STOR) rewards users for reducing (or in some instances increasing) demand with up to four hours notice if it is apparent that the system will be under strain. If large users can alter demand (at least 3MW, but smaller aggregated volumes can be accommodated too) for at least two hours with four hours notice up to three times a week then payments will be received.

There are two forms of service. Committed service requires the party to be available at all agreed times during a predefined 'availability window' (except where technical or safety reasons prevent this) and the system operator commits to pay for service availability for the length of the contract. The flexible service option allows the provider to indicate the hours of availability across a season (defined by the system operator) with actual availability declared on a weekly basis. A new product took effect from 1 April 2009 where a demand side participant can tender for up to 10 years of STOR.

At present STOR costs the system operator about £60mn/yr with about 10% being taken by the demand side. The system operator is keen to increase this. Indicative payments are in the order of £40,000 per MW per year.

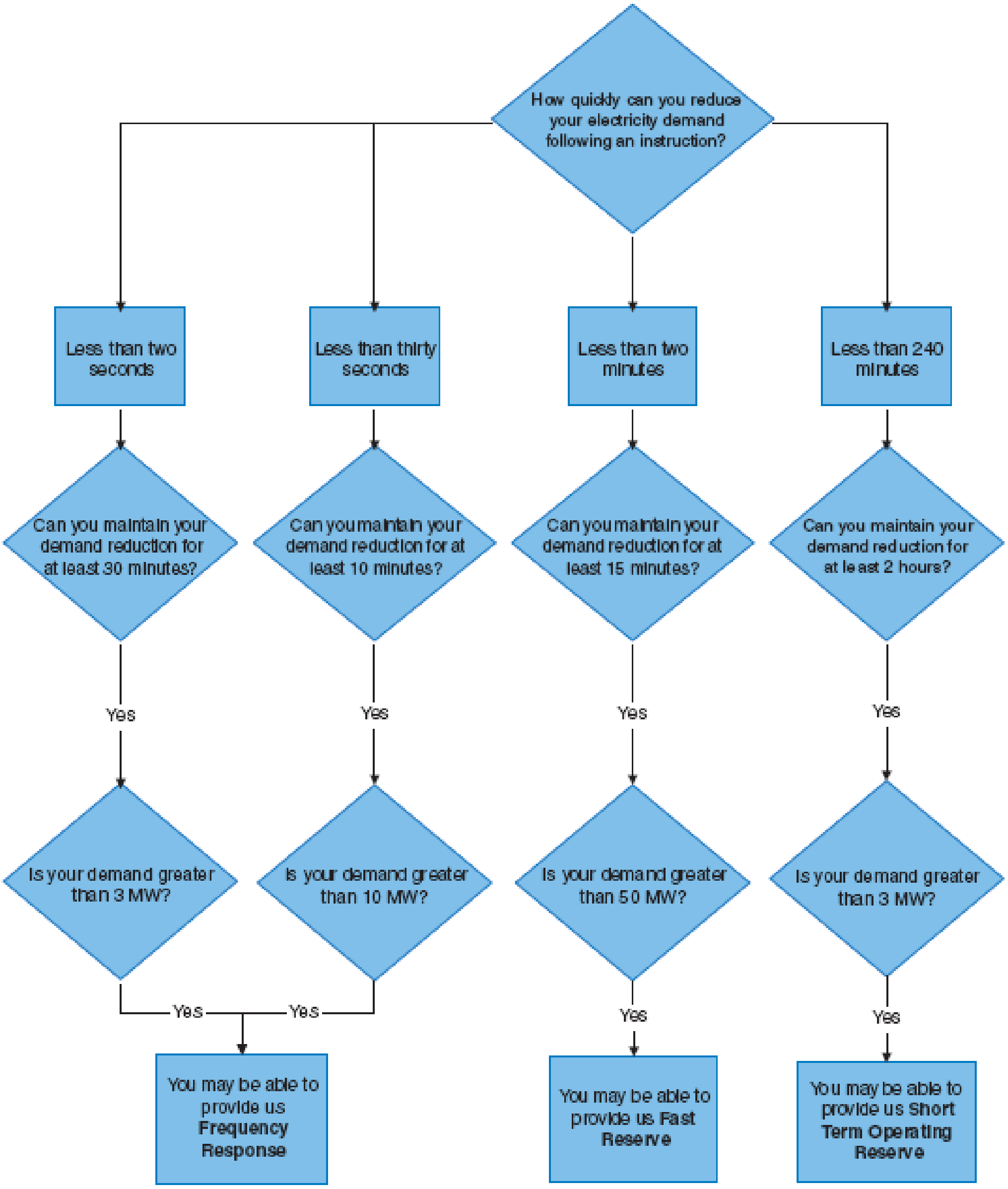
Fast reserve is a product which is closer to real time. A demand side participant agrees to alter their demand (more than 25MW/minute) within two minutes of notification for a period of at least 15 minutes and up to (typically) an hour. Like STOR the service is procured by competitive tender, although monthly rather than three times a year, and payments are made for availability (£/hr) and utilisation (£/MW/hr). An indication of the potential revenue for a demand side user is approximately £50,000 per MW per year.

Frequency response enables, via installed hardware on a user site, automatic changes to demand in response to a dip (or rise) in frequency. Users have two options. The first would automatically trip the user off supply if frequency falls below an agreed point and the second would automatically alter demand on a second-by-second basis. For most users the first option would probably be the most applicable. The service is procured via a GB-wide tender and is open to balancing mechanism and non-BM providers. The minimum requirements are that the user would have to demonstrate they can deliver the service and offer at least 3MW. Although no indicative revenues were provided they would be substantially higher than the two other response services. The cost to the system operator for this service during 2007-08 was £130mn and is expected to rise over time.

Constraint management services to alleviate localised power flow constraints on the high voltage transmission network, for example during a planned network maintenance activity. A typical demand side provider would be able to, on a pre-planned basis, shutdown its demand or run backup generation continuously for a sustained period, e.g. a number of days. Occasionally the need for the service would only be for defined periods during the daytime.

A major driver behind the development of demand-side ancillary services has been the financial incentives provided to the system operator. This "sliding scale" incentive provides the system operator with the chance of keeping a proportion of any reductions in its balancing costs below a target level—although it also has to pay a proportion of any increase in its balancing costs above that target level.

Can you provide a service to National Grid?



If you have answered **Yes** to all questions than please contact using the details overleaf. Please note the faster you can respond to an instruction the greater the value to National Grid.

If you have answered **No** to any question then consider if you could achieve the requirements by aggregating loads together, this can be on a National scale. A number of companies also provide aggregation services, details of these can be found overleaf.

Annex B

Useful further reading on Britain

1) Electricity distribution price control review policy paper - 5 December 2008

http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/POLICY%20PAPER%20DOCUMENT%20File%20problem%20use%20this%20one%2020081126%20PR.pdf

2) Electricity distribution price control review methodology and initial results paper- 8 May 2009

http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Methodology%20and%20Initial%20Results%20document.pdf

3) Regulating energy networks for the future: RPI-X@20 – 27 February 2009

http://www.ofgem.gov.uk/Networks/rpix20/publications/CD/Documents1/Principles%20Processes%20and%20Issues%20con%20doc_final%20-%20270209.pdf

4) Consultation on smart metering for electricity and gas – 11 May 2009

http://www.decc.gov.uk/en/content/cms/consultations/smart_metering/smart_metering.aspx

5) Distributed energy – further proposals for more flexible market and licensing arrangements – 18 June 2008

http://www.ofgem.gov.uk/Sustainability/Environment/Policy/SmallrGens/DistEng/Documents1/DE%20June%20con%20doc%20-%20FINAL.pdf

6) National Grid (system operator) balancing services
http://www.nationalgrid.com/uk/Electricity/Balancing/

Other useful links

http://www.electricitycommission.govt.nz/consultation/demandside

http://www.ucei.berkeley.edu/CSEM/conf2000/slides/wolfram_slides.pdf

http://www.ieadsm.org/ViewTask.aspx?ID=17&Task=8&Sort=1

http://www.gao.gov/new.items/d04844.pdf

Useful further reading on United States

Table 1: Studies of the Benefits of Existing Market-Based Pricing Programs for Regions and Specific Programs

Study title, author, date	Results/conclusions
"The Economics of Real-Time and Time-of-Use Pricing for Residential Consumers," King, June 2001	Pacific Gas and Electric has operated a time-of-use program since 1982, with about 85,000 participants as of 2001. Consumers have reduced their electricity usage during peak periods by 18%. As of the early 1990s, 80% of participants were saving $240 per year through the program, or about $16 million per year. The utility has also benefited from the shift in demand to off-peak.
"Evaluation of the Energy-Smart Pricing Plan: Final Report," Summit Blue Consulting for Community Energy Cooperative, Mar. 2004	Community Energy Cooperative of Chicago's demand-response program had 750 participating residential customers, representing a wide variety of neighborhoods and types of homes, in 2003, its first year of operation. Under day-ahead pricing, these customers saved an average of 19.6% on their energy bills, or more than $10 per month in 2003, for modestly cutting back on consumption during approximately 30 hours of peak demand during the summer months.
"Industrial Response to Electricity Real-Time Prices: Short Run and Long Run," Schwarz, et al., Oct. 2002	Real-time pricing by Duke Power in the Carolinas induced demand reductions of about 70 MW, or approximately 8% of consumption during four summer months of peak demand. This translates into long-term savings of about $2.7 million per year for the 110 industrial customers who participated during the period 1994 to 1999.
"Customer Response to Electricity Prices: Information to Support Wholesale Price Forecasting and Market Analysis," Braithwait for EPRI, Nov. 2001	Georgia Power's real-time pricing program, with about 1700 participants representing about 5,000 MW of demand, can count on a demand reduction of at least 750 MW when capacity is constrained and wholesale markets are tight. On a few days in summer 1999, Georgia Power's real-time prices reached levels as much as twice as high as those seen in previous years. Prices were moderately high on several days and spiked to an extremely high level on a few days. The very large industrial customers on hour-ahead rates reduced their purchases by about 30% from their normal rate on the moderately high-priced days and by nearly 60% during the two high-cost, capacity-constrained episodes.
"Analysis for 2002 GoodCents Select Program Critical Calls," Gulf Power, May 2003	Customers participating in Gulf Power's critical peak pricing program in 2002 on average consumed 50 percent less electricity during "critical periods"—when price was higher—than did a similar group of nonparticipating consumers. Participants also paid 11 percent less in total electricity bills because their total electricity expenditures rose slower than the similar group of nonparticipants.
"Demand Responsiveness in Electricity Markets," Lafferty, et al. for FERC, Jan. 2001	Residential customers in the Wisconsin Public Service Corporation's peak-load pricing program who faced a peak price that was double the off-peak price reduced their consumption during summer peak periods by about 12%, while those facing a peak price that was 8 times the off-peak price reduced their consumption by 15% to 20% during summer peak periods. At peak hours during heat waves, consumption was reduced by 31% relative to nonpeak noncritical days.
"Responsive Demand: The Opportunity in California," McKinsey and Company, Mar. 2002.	From July 1999 through August 2000, San Diego Gas and Electric Company charged residential customers electricity prices based on regional wholesale market prices. During this period, it provided customers with the electricity wholesale price index on their monthly statements. In June-August 2000, there was an unprecedented run-up in California wholesale electricity prices. As a result, the average customer's bill increased by 240% during these 3 months, compared with the same period in 1999. In response, during this period in 2000, customers reduced their usage by 5%.
"New York Independent System Operator (NYISO) Price-Responsive Load Program Evaluation: Final Report," Neenan Associates, Jan. 2002	The NYISO's demand bidding program provided over 25 MW of load reduction when summer peak prices were the highest in 2001. The program's scheduled load reductions are estimated to have reduced market prices by 0.3% to 0.9%. Total collateral benefits from reducing market prices are estimated to be $1.5 million in 2001. The program is expected to reduce the frequency of system emergencies and lessen the need for reliability programs.
"Framing Paper #1: Price-Responsive Load (PRL) Programs," Goldman for NEDRI, Mar. 2002	The New England Independent System Operator's, New England Demand-response Initiative (NEDRI) was used on six occasions in 2001 when prices frequently reached $1,000/MWh providing an average demand reduction of 17 MW.

Table 2: Studies of Potential Benefits of Demand-Response

Study title, author, date	Results/conclusions
Retrospective	
"The Financial and Physical Insurance Benefits of Price-Responsive Demand," Hirst, May 2002	If hourly pricing had been in place for 20% of California's retail electricity demand in 1999 and there had been a moderate amount of price responsiveness, the state's electricity costs would have been 4%, or $220 million lower. In 2000, electricity prices were almost four times higher and also much more volatile than in 1999. Hourly pricing for 20% of retail demand in 2000 would have saved consumers about $2.5 billion or 12 percent of the statewide power bill.
"Getting Out of the Dark: Market-based pricing could prevent future crises," Faruqui, et al., fall 2001	In California, during the energy crisis in summer 2000, if demand-response to hourly market-based retail prices had been in place, Californians could have reduced their peak demand by 193 MW, thereby reducing prices from peak hourly levels of $750 per MWh to $517 per MWh. For the summer season as a whole, energy costs would have been reduced on high-priced days by $81 million.
"Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets," Caves, Eakin and Faruqui, Apr. 2000	In late July 1999 in the Midwest, wholesale electricity prices spiked to $10,000 per MWh. If only 10% of the retail demand for electricity had faced real-time pricing and there had been a moderate amount of price responsiveness, electricity prices would have risen to only about $2,700, 73% percent less than the price actually observed. Having just a small fraction of industry demand facing real-time prices would significantly dampen price spikes.
Prospective	
Power System Economics: Designing Markets for Electricity, Stoft, 2002	Evaluating power markets broadly, the net benefits of demand with real-time pricing would be about 2 percent of the total spent on electricity. For the United States in 2003, that would amount to about $4.5 billion. This long-term estimate assumes that customers shift consumption from peak to off-peak periods, but that total consumption does not change. The estimate does not include potential benefits that accrue as a result of avoided blackouts or other service disruptions.
"Economic Assessment of RTO Policy," ICF Consulting for FERC, Feb. 2002	The potential benefits for U.S. electricity customers from adopting real-time pricing, with conservative assumptions about customers' magnitude of response and their ability for distributed generation, are estimated to be $7.5 billion annually, compared with the status quo by 2010, the first year the effects would be fully in place.
"White Paper: The Benefits of Demand-Side Management and Dynamic Pricing Programs," McKinsey and Company, May 2001	U.S. electricity customers could potentially realize benefits of $10 billion to $15 billion per year if they all participated in demand-response programs and, on average, shifted 5 percent to 8 percent of their consumption from peak to off-peak periods and curtailed consumption by another 4 percent to 7 percent. The switch to demand-response programs would avoid 250 peaking power plants at 125 MW each to handle peak demand, for a total of 31,250 MW of peak capacity (or $16 billion to build plants used to handle peak demand). Also avoided would be 680 billion cubic feet of natural gas usage and 31,000 tons of nitrous oxide pollution per year.
"The Western States Power Crisis: Imperatives and Opportunities," EPRI White Paper, June 2001	If adopted everywhere in the United States, demand-response programs could reduce demand for electricity by 45,000 MW or about 6 percent of forecasted peak baseline usage. In California, demand-response could reduce demand by 8.7% and offset the need for new capacity by eliminating 57% of the forecasted load growth during the next several years.
"The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response," Braithwait and Faruqui, Mar. 2001	Based on demand-response data from existing utility real-time pricing programs and actual California data for summer 2000, customer response to hourly market-based retail prices could generate demand reductions of 1,000 to 2,000 MW, reduce summer peak demand, retail prices by 6% to 19%, and produce energy cost savings ranging from $0.3 to $1.2 billion in California alone.
"The Feasibility of Implementing Dynamic Pricing," California Energy Commission, Oct. 2003	California could reduce its peak energy demand by 5% to 24% within a decade by implementing dynamic pricing and installing advanced real-time meters for all nonagricultural energy customers.

Both of these tables are taken from http://www.gao.gov/new.items/d04844.pdf.