**OVERCOMING BARRIERS TO
SCHEDULING EMBEDDED
GENERATION TO SUPPORT
DISTRIBUTION NETWORKS**

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Overcoming barriers to scheduling embedded generation to support distribution networks

by

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Summary

Current scheduling of embedded generation for distribution in the UK is limited and patchy. Some DNOs actively schedule while others do none. The literature on the subject is mainly about accommodating volatile wind output, and optimising island systems, for both cost of supply and network stability. The forthcoming NETA will lower prices, expose unpredictable generation to imbalance markets and could introduce punitive constraint payments on DNOs, but at the same time create a dynamic market for both power and ancillary services from embedded generators. Most renewable generators either run as base load (e.g. waste) or according to the vagaries of the weather (e.g. wind, hydro), so offer little scope for scheduling other than 'off'. CHP plant is normally heat-led for industrial processes or building needs, but supplementary firing or thermal storage often allow considerable scope for scheduling. Micro-CHP with thermal storage could provide short-term scheduling, but tends to be running anyway during the evening peak. Standby generation appears to be ideal for scheduling, but in practice operators may be unwilling to run parallel with the network, and noise and pollution problems may preclude frequent operation.

Statistical analysis can be applied to calculate the reliability of several generators compared to one; with a large number of generators such as micro-CHP reliability of a proportion of load is close to unity. The type of communication for generation used will depend on requirements for bandwidth, cost, reliability and whether it is bundled with other services. With high levels of deeply embedded, small-scale generation using induction machines, voltage control and black start capability will become important concerns on 11kV and LV networks. This will require increased generation monitoring and remote control of switchgear. Examples of cost benefits from scheduling are given, including deferred reinforcement, increased exports on non-firm connections, and reductions in customer disconnections. In many cases potential savings far outweigh the cost of communications. A lively seminar was held at EA Technology to disseminate and debate this work. The overriding question to emerge was who would take on responsibilities and risks, and who would reap the benefits, of embedded generation on more active networks.

Contents

Page

1   Introduction

Electricity distribution networks were designed primarily for top-down power flows from the National Grid supply points to consumers. Increasing amounts of CHP and renewable plant are being connected to the distribution system. This is known as embedded plant, and it is expected to reach about 20% of generation capacity by 2010 if Government targets for renewables (10% of electricity production) and CHP (10GW of installed capacity) are met. Most of this plant either runs continuously, or to suit customer requirements for heat and power, or to maximise profits from electricity export. Little control is exercised by distribution network operators (DNOs). In order to manage networks efficiently and prevent power problems such as reverse power flow, excessive fault levels and voltages outside statutory limits, there is likely to be an increasing need for some degree of control and monitoring of embedded plant by DNOs. This would also benefit generators by increasing total exports, reducing interruptions to their connection, and possibly providing additional revenues in exchange for network support.

The DTI has recognised that there are barriers to be overcome in achieving higher levels of embedded generation, and have explicitly recognised the need to "encourage distribution companies to manage actively embedded generation on networks". Therefore they have funded this project, through the DTI's New & Renewable programme, to examine the potential for scheduling generation for distribution purposes, costs and benefits, and how barriers may be overcome. Additional support was generously provided by a number of UK distribution companies through EA Technology's Strategic Technology Programme. In addition to this report, a free seminar was organised as part of the project to disseminate results to a wider audience and to collect views from a cross-section of the electricity industry.

Section 2 reviews the current situation and equivalent arrangements on the NGC system. Section 3 considers the impeding impacts of NETA, and existing engineering standards for connection of generation. Different types of generator, and the implications for scheduling and other support services, are described in Section 4. Generic types of scheduling are described in Section 5, and the scope for scheduling various types of generators is given in Section 6. The increase in overall reliability resulting from having many generators is discussed in Section 7. Communication requirements are described in Section 8, and examples of network management using monitoring and control of generation are given in Section 9. Section 10 looks at metering arrangements, and potential conflicts between supply and distribution needs. Some examples of costs and benefits of scheduling are given in Section 11. The outcome of the seminar is described in Section 12, while conclusions are drawn in Section 13. Finally, references are provided in Section 14.

2 Current Situation and Existing Arrangements

2.1 Survey of companies

A survey of six distribution companies was carried out to establish the extent of scheduling embedded generation for distribution purposes. The companies have not been identified, but the results in summary are as follows:

Company A

Requests certain wind farms to disconnect when load is low and output is high - verbally by telephone. Also has scheduling arrangements with large CHP plant on 132kV network, set in advance, to prevent network becoming over-stressed.

Company B

No scheduling of embedded generation plant.

Company C

The company owns no embedded generation plant, and has no arrangements with private generators for scheduling.

Company D

No scheduling arrangements, except (under conditions of licence) to disconnect at times of network stress, maintenance etc.; verbally by telephone.

Company E

Two operational sites to provide power in remote areas on loss of supply on 33kV and 11kV feeders. Also used for peak-lopping through arrangement with supply business.

Company F

Before splitting into separate companies, owned embedded diesel generation plant for network security. This is now owned by another company, and is sometimes used when the network is stressed. However, its availability is not firm enough for it to be reliable. Negotiations are going on with developers of embedded generation for automatic voltage control. This would involve automatically reducing output, or if necessary disconnecting, generation when the local load to absorb power is low. The incentive for the generator is improved access to the network under this proviso (for example connecting to 11kV line instead of paying cost of connection back to transformer).

Overall, arrangements are patchy and *ad hoc*. Some companies were very interested in developments in this area, as they recognise there are problems for the companies and generators managing the inputs. Some companies are in the process of exploring new forms of arrangement with generators. Control varies from telephone calls to automatic electro-mechanical control.

2.2　Review of literature

While there is a great deal of literature on renewables and embedded generation in general, information on scheduling is scarce. Very small plant on the LV network is almost never scheduled, while large multi-megawatt plant may have established scheduling arrangements which are not of topical interest. Of most interest is the small-medium plant but information is hard to come by since it is mainly small companies making private arrangements.

Much of the work has focused on wind generation, because it is growing rapidly and because the output varies rapidly and is hard to predict. Controlling wind and conventional generation on islands without access to a high voltage transmission system is of particular importance. Christensen et al [1] review methods and models for various applications. They report that windmills operated by the utility NESA in the Eltra area of Denmark each have computers which carry out local control such as pitch and start-top sequences, and download data hourly to a central control room for monitoring purposes. NESA also uses software to predict wind output up to 36 hours ahead. Denmark also has a very high level of CHP for buildings, output from which is also modelled and predictable to within about 5% for the next day, partly as a result of 3-part tariffs to encourage production when demand is high. The combination of these two large embedded energy sources means that the remaining generation must be very flexible: *"At all times the spinning reserve must be adjusted according to the forecast and actual production from CHP units and wind turbines. To secure the system the dispatcher must not only ensure the spinning reserve but also the possibility of reducing production from ... power stations when production from CHP units and wind turbines increases"[1]* . A case of the tail wagging the dog? The Eltra area is expected to export the equivalent of about 8% of annual demand by 2005. Clearly this is very much an actively managed system.

Dialynas et al[2] describe the modelling of the wind and fossil fuel generation on the island of Crete. They conclude that instability caused by wind generation can be overcome using sufficient conventional spinning reserve. The modelling assumed generation scheduling and load reduction to prevent network branch overloading.

Nogaret et al[3] present a control system for the optimal control of wind and diesel generation supplying an autonomous network on the island of Lemnos. The control aims to minimise fuel use, while maintaining system stability. Operational data are collected and analysed every minute, and decisions to stop or start plant are made every 10 minutes. The system appears to offer savings over manual control; for example the automatic system favours running the larger diesel generator over the small generator because it uses a cheaper type of fuel.

All of these systems appear to be operated by a vertically integrated utility which has goals of minimising energy costs as well as operating the network efficiently. With separate generation, supply and distribution businesses in the UK, such a unified approach will be difficult to achieve.

Egroups discussion group - embedded-generation

This is a fairly active internet group[4] which sometimes contains interesting information, but is US dominated, usually anti-utility, and is often taken up with philosophical, ethical or fanciful technical exchanges. It does sometimes contain useful links to web sites and documents.

2.3 Cost of standby generation in the Pool/NGC system

The NGC pays for two types of reserve capacity: spinning reserve from plant already running and synchronised, and standing reserve plant (or load) which can be called upon to generate (or shed load) at short notice (typically 1-20 minutes). Standing reserve is the closest comparison to reserve capacity on the distribution system. Typically, a standing reserve generator/load shedder will be called upon to operate 20-30 times per year, and derive a total income from this of around £10/kW, made up from a mixture of annual availability and per-use utilisation payments.

2.4 Use of mobile generators

Some information is available on use of mobile generators during the supply interruptions following the Boxing Day storm of 1998. NORWEB used 32 mobile generators to supply 62 customers (2 customers/generator) while Scottish Power used 200 generators to supply 900 customers (4.5 customers/generator). These numbers suggest large customers for whom power was very important, such as hospitals. Network support would perhaps more typically be provided by a diesel generator on a lorry supplying up to 1MW to a local substation, to a few hundred customers.

A hire company offering such generators quoted a weekly hire full list price of £3,554 for a 750kVA generator, unlimited running, excluding fuel and extras such as cables. With a 20% discount, this equates to about £4/kVA/week. However, it is difficult to compare this cost of expensive generation for a fixed period, with a call-up charge per use like the NGC standby generator fees.

A 150kVA generator costs about £40,000, and a 500kVA generator about £120,000, with all-in running costs around 5p/kWh. Most can operate at LV or HV (11kV). One REC has one 500kVA generator, eight 150kVA generators and three 200kVA generators, giving a total capacity of 2.3MW. They are mainly used for routine maintenance throughout the year; the 500kVA generator was used a total of 27 times in 1998; 18 times at LV and 9 times at HV. Using embedded generation to displace some of this plant could result in significant cost savings.

2.5 Forms of payment for scheduling embedded generation

Payment arrangements for scheduling embedded generation are normally part of a commercial contract and therefore confidential. In the case of turning generators off when the network becomes stressed, this may be part of the agreement without compensation for the lost export earnings. There are examples of large generators with non-firm connections. In exchange for being constrained in output at times of network stress, they can achieve higher exports overall because the non-firm export capacity is considerably higher, for most of the time, than would be allowed for a 'worst case' firm connection. Most current arrangements would appear to be fairly informal.

3 Regulations and Standards

3.1 Effect of NETA on embedded generators

The effects of the New Electricity Trading Arrangements (NETA) on embedded generation have been considered by Ofgem in *The New Electricity Trading Arrangements*[5]. Falls in wholesale prices for electricity will affect schemes in different ways. Renewable generators operating under NFFO contracts will be unaffected until the contract expires, because they have guaranteed prices. Exporting CHP sites and non-NFFO renewable generators will be adversely affected by lower export prices, but there are options available to mitigate this effect.

Only large plant (above 100MW as a result of the licence exemption review) will be obliged to become a signatory to the Balancing and Settlement Code (BSC) which effectively replaces Pool membership. The vast majority of CHP and renewables schemes fall below this threshold, and most will therefore trade through a third party such as an aggregator.

Increased use of bilateral markets, especially short-term (24 hours ahead or less) will increase the opportunities for embedded generators to sell power, particularly those who can guarantee output or generate flexibility to match demand. Generators with unpredictable output, such as wind, will be exposed to imbalance charges, usually indirectly through an aggregator. It will be in the interest of aggregators to have a wide portfolio of plant to spread the risk of variable output and plant failure. As the timescales of market making shorten (time between gate closure and actual trading period), this should benefit generators affected by weather. In particular, wind generators may be able to predict output (though not control it) fairly accurately up to a few hours ahead using weather forecasts and heuristic models. At present it is proposed to make gate closure 3.5 hours before trading starts, which is short enough for wind generators to have a reasonable idea of their output during the trading period.

Many generators will have incentives to schedule load more actively to obtain better prices in the energy markets. This could equally be used for distribution purposes. An attractive contract from either business should be worth consideration. Aggregators with several generators in the same geographic area should be in a good position to negotiate with the local distribution company for scheduling plant.

3.1.1 Constraint payments

One of the most significant issues in NETA for DNOs could be constraint payments. Suppose an embedded generator contracts with a supplier to supply a certain amount of power at a certain time, then is unable to deliver this due to problems on the distribution network constraining or preventing export. In the current NETA proposals, it appears that the DNO may be liable for charges on the generator resulting from failing to fulfil the contract, although this is still subject to ongoing consultation. Conflicts of interest could arise with scheduling for distribution, where this constrained output. Such payments would not apply to generators with a non-firm capacity however.

Constraint payments are a serious concern to DNOs who could be liable for very high payments to some generators. If the export constraint is caused by a fault beyond the point of supply (the most likely case) then the DNO is compensating the generator for failure of

assets which the generator has made no payment for; this is manifestly unfair. (In addition, the DNO has to pay for supply interruptions to demand customers who have contributed to the assets; this is fair in principle.) By the same reasoning, generator customers should be compensated for loss of supply, but not for loss of export. One solution would be for generators who wanted a firm export connection to pay a standing charge for this, and receive some form of constraint payments. Alternatively, connections would be non-firm and there would be no constraint payments. Due to the payments to demand customers, DNOs always have a strong incentive to minimise network failures. Failures of the connection up to the point of supply, when it is owned and maintained by the DNO, should however result in some form of compensation to the generator. Whether full constraint payments should be made in either case is debatable. Demand customers, however large or small, receive a flat rate for loss of supply over a certain time limit and commercial customers are never compensated for actual loss of business. Where generation was scheduled, it is likely that this would be under an arrangement which avoided constraint payments in exchange for more favourable export opportunities.

3.2   Engineering standard G77

Strictly speaking, Engineering standard G77[6] is only for pv connection, but is likely to be applied to other domestic-scale generators. It requires that the inverter disconnects from the network within 5 seconds of detecting a voltage or frequency problem, or loss of mains, and does not reconnect until at least 3 minutes after the supply from the DNO system has been restored to within the limits already specified. The most likely scheduling of this type of generation would be to come on or turn off when required; this would appear not to be affected by G77.

3.3   Engineering recommendation P2/5

This recommendation defines the effective contribution of generation to network capacity. It was written in 1978 and refers to the type of plant around at the time - manned steam and gas turbine. Studies of such plant had shown that for circuits with more than two generators, the probability of losing two units plus one third of the remaining generation was about the same as the probability of losing one transmission circuit. This assumed 86% generator availability excluding planned outages. Therefore two thirds of 'declared net capability' is taken as the effective contribution of generation to firm capacity. This does not seem unreasonable for modern plant which is normally operating, but would be inappropriate for intermittent plant or unpredictable generation such as wind. The industry is aware that P2/5 needs updating. In reality, small generators which the DNO may not even be aware of will reduce peak load and hence the *de facto* required capacity.

3.4 Consultation on electricity network management

The DTI issued a consultation document 'Electricity Network Management Issues', 25 November 1999 seeking industry views on network access, management and charging. The intention is to decide on changes 'needed to level the playing field for embedded generation access to distribution networks'. Several areas are proposed for discussion. The most relevant to scheduling for distribution purposes are:

- consideration of embedded generation as an alternative to network augmentation
- obtaining security services from embedded generation and incentives to do so
- arrangements for the NGC to consider use of embedded generators for ancillary services
- the need for revision of P2/5 (see above)
- opportunities for new generators to make proposals which will avoid the need for network reinforcement
- rules for connection to, and use of, distribution networks
- medium to long term, encourage distribution companies to design networks to accommodate increased levels of embedded generation, e.g. more interconnection

and in particular

- encourage distribution companies to manage actively embedded generation on networks, providing incentives for network security, real time monitoring of generation status and real time control of generation

The Government has set up a working group on these issues chaired by Ofgem.

Clearly, the Government has accepted that there are problems with the current arrangements for embedded generation, and want to identify changes that could encourage and accommodate more such generation. One likely consequence of any change would be to increase the amount of control of embedded plant on distribution networks.

4 Types of Generator

There are three basic types of rotational electric generator:

- Direct Current (dc) generators
- Induction or asynchronous Alternating Current (ac) generators
- Synchronous ac generators

The source of mechanical power used to turn the generator (wind turbine, diesel engine, gas turbine etc.) is called the *prime mover*. Since dc generators are only normally used to supply dc circuits, they are not used for embedded generation on ac systems, and are not considered here.

4.1 Induction ac generators

Most smaller embedded rotational generators are induction machines, and can in fact behave as a motor or a generator. They are called induction machines because the rotor voltage (which produces the rotor current and the rotor magnetic field) is *induced* in the rotor windings rather than using a physical wired connection[7]. They have the distinguishing feature that no dc field is required to run the machine. They are cheap, simple, rugged, and

do not have to run synchronously with the network, although they are slightly less efficient than synchronous machines.

When a stationary induction machine is connected to an ac circuit without any torque applied to the shaft, it behaves as a motor. Its speed will increase until it is running slightly slower than the synchronisation speed of the ac supply. The difference induces just sufficient torque to overcome frictional losses in the motor (a perfect motor with no losses would become synchronous with the ac supply). Similarly, if connected to a load, the speed will increase until some point below synchronous speed where the induced torque matches the total load. The power factor of the motor is unity at synchronous speed, and decreases as the difference in speed increases.

However, if a torque is applied to the machine to make it run faster than synchronous speed, for example from a wind turbine, it starts to act as a generator. Because it lacks a separate field circuit, an induction generator cannot produce reactive power. In fact it consumes reactive power (also known as 'importing Vars'), and an external source of reactive power must be connected to it at all times to maintain its stator magnetic field. The external power system also normally controls the output voltage of the generator.

Induction generators have the important advantage that they do not have to be driven at fixed speed. As long as the machine's speed is some value greater than the synchronous speed of the power system, it will function as a generator. Power factor correction can be achieved using capacitors.

It is possible to run induction generators without an external network, by using a bank of capacitors to provide the reactive power. Induction generators can start without an external circuit provided there is residual magnetism in its field circuit to produce a voltage, which creates a current increasing the voltage, and so on. It may be necessary to use another power source (e.g. a battery) to run it briefly as a motor in order to induce some magnetic flux - this is called 'flashing'.

The main problem is that the voltage can vary as the load varies, particularly with reactive loads because the reactive power is diverted to the load, causing a drop in voltage from the generator, although this can be overcome with additional equipment. Although frequency varies with loads, this variation is normally limited to below 5% which is acceptable in isolated or emergency standalone applications.

Because of their small size per kW, and minimal requirements for control or maintenance, most smaller rotational embedded generators are induction machines. However, they are not very suitable for standalone applications due to problems of control.

4.2   Synchronous ac generators

In a synchronous generator, a dc current is applied to the rotor winding, which produces a magnetic field. In effect, the rotor is a large rotating electromagnet. The rotor is turned by a prime mover (e.g. a gas turbine) producing a rotating magnetic field within the machine. This field induces a three-phase set of voltages within the stator windings. The term synchronous arises because the electrical frequency is locked into the mechanical rotational speed. Thus if supplying power to a 50Hz external circuit, a synchronous generator must rotate at a fixed speed, otherwise damaging currents and voltages will result. This means in turn that the prime mover must turn the rotor at constant speed. In practice, this means the source of prime movement (e.g. diesel engine) driving the shaft runs at constant speed.

The dc current is supplied to the rotor windings either by a separate dc source via slip rings and brushes, or from a small ac generator called a brushless exciter mounted on the same shaft. The ac output from this is rectified to dc and fed into the main rotor windings. This generator itself also needs power in its field windings to start. In order to make the machine completely independent of external power sources, a third generator called a pilot exciter may be used. This is a small ac generator with permanent magnets mounted on the main rotor shaft. On starting up, this generates power for the field circuits of the exciter, which in turn generates power for the field circuit of the main machine.

When the load increases on the prime mover, the speed tends to decrease. Without control this would be non-linear, but there is usually a governor to make the response linear. All governors produce a drop in speed with increased load, typically a 2-4% reduction from no-load speed to full-load speed. This is called a drooping characteristic. There is usually also a set-point control to change the no-load speed of the prime mover.

4.2.1   Effect of load - standalone generator

Assuming the generator always runs at constant speed, a change in load without compensation will affect the terminal voltage.

- Adding lagging (inductive) load will decrease terminal voltage significantly
- Adding unity power factor load will decrease terminal voltage slightly
- Adding leading (capacitive) load will cause terminal voltage to rise

To prevent voltage fluctuations, field current is varied by altering the resistance on the field circuits.

1. The real and reactive power supplied will be the amount demanded by the attached load.
2. The governor set points of the generator control the operating frequency of the power system.
3. The field current (or field regulator set points) controls the terminal voltage of the power system.

4.2.2   Operating in parallel with the network

The network is treated idealistically as an 'infinite bus', that is a system whose voltage and frequency cannot be altered by any connected load or generator. Consider a generator connected to an infinite bus and load, as shown in Figure 1.
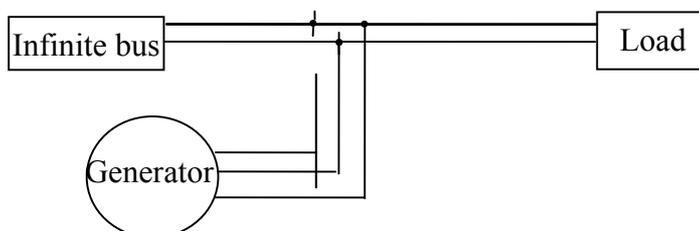

Figure 1: Generator connected to infinite bus with load

If at the moment of connection the frequency of the generator is slightly higher than the system frequency, the generator will synchronise with the system and supply a small amount of power. If however the generator frequency is lower than the system, the system will

supply power to the generator to bring it up to the system frequency - i.e. the generator will become a motor absorbing power. Therefore generators are always controlled to come on line at a frequency slightly above that of the system. Many have a reverse power trip to disconnect them if they start to absorb power. If the no-load set point speed setting is raised, the frequency cannot change because it is fixed by the system, but instead the power increases to the point on the load/frequency curve where the power supplied is higher but the frequency equals the system frequency. If the generator output exceeds the load, excess power will flow into the infinite bus.

1. The frequency and terminal voltage of the generator are controlled by the system to which it is connected.
2. The governor set points of the generator control the real power supplied by the generator.
3. The field current (or field regulator set points) controls the reactive power supplied by the generator to the system.

Therefore, unlike an induction generator, a synchronous generator can supply reactive power.

4.3   Implications of generator characteristics for scheduling

Deferred reinforcement

Requires generator to run reliably at times of high load, so energy source must be very reliable (e.g. gas; not wind or hydro). Control, or at least monitoring of output, would increase confidence in generator. A large number of dispersed generators would be preferable to a small number of large ones, because diversity increases reliability. Deferment as a result of growing embedded generation is already happening in some areas, even if the distribution companies are not fully aware of how much generation is operating.

Supporting network for maintenance
Assuming generator is not running islanded but is supplementing grid supplies, this has similar requirements to deferred reinforcement.

Emergency support

Generators need to be called upon to run at short notice. Therefore the energy source must be reliable. Automatic starting, or a permanently manned site, will be preferable. However, since they may not be needed for more than a few hours, reliability is not so important (especially if several are used at once). Islanded operation is possible, requiring synchronous machines with good control. In some cases generators may need to 'black start' on a dead network, which will only apply to large generators specially suited to this purpose. Generators which are normally running (e.g. landfill gas) are unlikely to be very useful in this role, because their output will not be displacing load normally supplied from the network. Monitoring of output will be required.

Voltage support

Active voltage control will require two-way communications and additional equipment on the generator, adding to cost and likely to be justified only on large synchronous machines such as industrial plant. However, smaller generators will raise voltages on long lines (e.g. rural generator on 11kV line) anyway; even if the generator does not control its output, feedback on the local voltage can be used to control the network voltage via tap changers in the transformer upstream. There is some evidence that wind generation can provide useful voltage support; though the energy source is unreliable, output is generally higher in the

winter when demands are higher. Embedded generation can cause voltage to rise too far in conditions of low demand and high output; in these circumstances monitoring of generation can provide valuable feedback for network management. If necessary generators could then be turned off.

Reactive power (VAr)

Induction machines import VArs but synchronous machines can be controlled to import or export VArs. This is only likely to be practical on larger machines, and will require two-way communications. Generators will need to run most of the time to provide a useful service.

Summary

- There is a wide variation in support functions, depending on characteristics of the source, prime mover and electrical generator
- Small sites and uncontrolled generation is unsuitable for most support roles
- Large, controllable sites with synchronous generators have the widest support roles, but are also likely to have operational on-site constraints
- Reliability, either individually or through numbers, is important to increase the potential support role
- Feedback from the generator is at least as important as controlling the generator.

Table 1 shows the information needed to support different functions. Most types of information flow are useful in most support roles. Feedback on current output and status is particularly important, required for all roles.

Table 1: Information flows to support network functions

Item	Direction	Support function*					
		Def	Sup	Em	Volt	VAr	Red
Command to turn on/turn off now/soon	In	♰	♰	♰	♰		♰
Information on current output	Out	♰	♰	♰	♰	♰	♰
Command to modulate output	In	♰	♰	♰	♰		♰
Command to modulate power factor	In					♰	
Next day plant schedule	Out	♰	♰	♰			♰
Next day required schedule	In	♰	♰				♰

* Def=Deferred reinforcement; Sup= Supporting network for maintenance etc.;

Em=Emergency support; Volt=Voltage support; VAr=VAr support;

Red=Reduce or turn off to protect network.

5   Types of Monitoring and Scheduling for Distribution

This section considers scenarios where scheduling could be employed; its purpose, communications media used, and benefits. Most scheduling of embedded generation is done for:

- On-site requirements, e.g. CHP scheduled to match heat loads
- Operational reasons, e.g. maintenance
- Electricity prices, e.g. maximise exports at times of high prices

Importantly, plant operating under NFFO or equivalent schemes is guaranteed a fixed unit price so tries to maximise total output regardless of time. This section considers scheduling for distribution purposes only. Use of scheduling for active network management are covered in a later section. Scheduling can benefit the network by reducing peak loads, changing power flows when the network is stressed, and providing ancillary services such as reactive power. The following sections consider the different types of scheduling which are possible. Each section has a summary of the following:

- Time scale: Time period over which scheduling arranged
- Media: Communications media used to implement
- DNO benefits: Benefits to distribution of this type of scheduling
- Generator benefits: Benefits to generator of this type of scheduling

5.1   Scheduling generator maintenance

For generators which normally run continuously, about half the time they are off is for routine maintenance, the other half being due to faults. Therefore scheduling maintenance to avoid times when the network was stressed would increase effective availability. To some extent this already happens because times of high on-site demand and high export prices typically coincide with high network load, but the DNO is normally unaware of maintenance periods.

Time scale

Planned ahead, e.g. monthly schedule agreed.

Media

Manual, text-based; fax, email.

DNO benefits

Greater confidence that generation will be running at times of network stress, hence less chance of failure and possibly deferred reinforcement.

Generator benefits

Financial incentive.

5.2   Generator output at times of high load

Historical peak loads on transformers form the basis of decisions on upgrading equipment, and these are affected by embedded generation. The peak load is usually the highest load, recorded outside times of known load transfer, adjusted for temperature effects. It will of course equal the demand plus losses, minus embedded generation, though these will not be known separately. Large and some medium-sized generators will have half-hourly metering, but this data will be commercially confidential and normally only available to the supply company. However, since only peak values are required, sites with such metering could provide the output for a given period(s), such as time of system peak, TRIAD periods, TRIAD warning periods etc. Small amounts of data like this would not be commercially sensitive, so supply companies should be willing to make it available. For sites without half-hourly metering, it would probably be much easier (and useful for internal purposes) to log output over the year, than put in special equipment and communications to

only record on a signal to do so, e.g. at TRIAD warning periods; storage is cheaper than communications. Data would then be extracted manually as for metered data.

Time scale

Provided annually after winter period, e.g. April.

Media

Collected locally, sent by email or disk.

DNO benefits

Provides data on output of generators at time of network peaks for network planning. Data from a large number of generators will give statistical information for input to probabilistic models of aggregate 'firm generation capacity'. Reduced reinforcement, more data on load flows.

Generator benefits

Financial incentive could be provided for guaranteed output at certain times; data needed to confirm output. Providing data could be a condition of connection.

5.3   Regular scheduling

Generators could be scheduled to run on a regular basis at certain times. This could be around peak load, to defer reinforcement of substation. Generation likely to be at LV (many small generators), 11kV or 33kV. Needed perhaps 1-5% of time. Typically, peak occurs around 17:30 in the winter, but on some transformers with large commercial loads will occur around midday, and on transformers with high E7 load shortly after midnight. Such loads are fairly predictable from about a day ahead from weather forecasts and historical knowledge, so could be scheduled say 24 h in advance. Generation will usually be required when electricity prices are high (almost by definition), so plant will often be running anyway for supply reasons. Could be permanent arrangement.

Time scale

Agreed annually or when requirements change.

Media

Manual, text-based; fax, email.

DNO benefits

Reduced network peaks (though in present situation, reinforcement is more likely option).

Generator benefits

Financial incentive, compensating for any reduced income on supply side.

5.4   As required scheduling on/off

Generators could be requested to run, or not run, at certain, unplanned times with agreed notice. Reasons for requiring generators to go off would include to avoid back-feeding at times of low demand, and to prevent voltage rise. This situation could apply at any voltage level, but is more likely at lower levels where aggregate local demand can drop very low at times. Times when demand is low is predictable

but times of high output for some generators (wind, hydro) are not. Hence a requirement to switch off is likely to be at short notice. When to turn on again depends on knowledge about future output and load. Simple arrangement would be to turn on when load recovers to exceed maximum generator output, though this likely to lose some generation. By definition, electricity prices are usually low when demand is low so the loss of revenue should be reduced. Such arrangements could remain in place until the network configuration or load patterns change. Note that this is the only type of 'scheduling' which can be applied to variable unconstrained renewable generators (wind, hydro and PV without storage) which generate at maximum output according to resource available.

Reasons for generators to be requested to go on would be to support the network when demand was high or there were constraints on power flows from higher up the network.

For on-site generators, agreement to this type of scheduling could be in exchange for cheaper supply arrangements. A non-firm supply could be provided in some cases, much more cheaply, in exchange for constraints on generation. On-site generators could have a variable capacity charge, normally corresponding to net import with base-load generator running, but higher when generator was off for maintenance etc. This would be much cheaper than having full no-generation capacity all the time. In order to confirm machines ran, require record of operation, either from local logging or two-way communications.

Time scale

From days ahead to minutes ahead.

Media

Depends on notice period: Days - hours, could use manual messages phone, fax, email.

Minutes - seconds, requires direct signalling which could be two-way for status and confirmation.

DNO benefits

Support for network (generation on) or reducing stress, fault levels (off). Avoid constraint payments to generators on (cheaper) non-firm connections.

Generator benefits

Financial incentives as payment for scheduled output or reduced connection charges. Pure generators such as wind would lose money when unable to export, but connection would be much cheaper.

5.4.1 Interruptible gas supplies

Many large (particularly industrial) customers with CHP plant have gas supplies which because they are interruptible are cheaper. Gas interruptions are likely to occur at times of high demand from consumer and possibly CCGT gas fired generation, typically in cold weather, so often coincide with high electricity demand. Usually, interruptions start to occur when demand exceeds 85% of the peak day demand[8]. More notice of interruptions would be useful to DNOs so that they would know when generation was going to drop out. Scheduling gas-fired plant would have to take into account interruptible gas supplies. A minimum notice

period of 5 hours is given for interruptions. This may be sufficient for the DNO to reschedule.

5.5 Reactive power control

While induction generators always absorb reactive power, synchronous generators can produce varying amounts of reactive power. The NGC system uses generators' ability to generate reactive power as a means of controlling system losses and providing voltage control. A similar approach could be used within distribution networks. Some factors work against this:

- The predominantly 'top down' energy flows in distribution networks are less sensitive to power factor. Where there is a problem, a static VAr compensator is usually the cheapest and favoured option (however, increasing embedded generation could make active more compensation desirable).
- Tariffs carry a penalty for poor (lagging) power factor because it increases losses, giving customers an incentive to install equipment (usually capacitors) to improve the power factor.
- Embedded generators are usually inhibited from operating with leading power factor. Distribution companies would probably be wary of allowing injections of VArs into the network, but it is technically possible.

Time scale

Minutes or less, continuous control.

Media

Automatic SCADA(system control and data acquisition)-type system.

DNO benefits

Improved power quality, reduced losses.

Generator benefits

Financial payments for service.

6 Characteristics of Embedded Generation for Scheduling

6.1 Wind

At present, wind farms generate for maximum output at all times so are completely unscheduled. Some research is going into storage, using wind to produce hydrogen which can be stored and used in some form of fuel cells to regenerate electricity. This is some way from commercial exploitation, but could one day make wind farms with this form of storage a very controllable, if less efficient, source of electricity. Other forms of storage which could benefit wind and other types of uncontrolled generation include:

- batteries - small-scale only with current technology
- mechanical rotating - prototype at present
- compressed air - probably small-scale, trials in vehicles at present

- the hybrid fuel cell/battery technology being developed as the REGENESYS system

None of these appears to be commercially viable at present, but rapid development is likely in some areas.

For conventional wind generation, there is no scope for scheduling other than 'off'. Turbines have an automatic safety cut-off at high wind speeds. Most wind sites are unmanned and remote, so powerline, SCADA or radio telephone communication would be the most suitable media for scheduling.

6.2   Photovoltaics

Photovoltaics presently provide an insignificant amount of embedded generation and have not featured in the NFFO . Like wind, photovoltaic cells produce electricity according to the solar input, and are completely unscheduled although output conveniently coincides with some commercial loads such as cooling and office power. As with wind, storage unlikely to be economic. With such small systems, automatic protection would probably be relied upon without external communications.

6.3   Small-scale hydro

There are two main types of hydro - low head and high head. High head systems require smaller turbines because the pressure is much greater, but fewer sites are available and are more likely to be from dams. All large-scale hydro schemes are high-head, whereas most small-scale hydro is low-head, 'run-of-river' without storage. Typically these are from weirs or locks, or old water mill sites with a small dam and penstock to divert the water through a turbine. Others use a siphon. There is little scope for scheduling output, which varies according to river flow. A limited amount might be possible where there was a dam, but it is unlikely that the increased capital cost could be justified. With flat-rate NFFO prices there is no incentive to vary output. As with wind, most hydro sites are unmanned and remote, so powerline, SCADA or radio telephone communication would be the most suitable media for scheduling 'off'.

6.4   Landfill gas

All landfill sites operate at approximately constant output although there is some variation due to weather effects. Output gradually rises then falls over the lifetime of the site, typically 10-25 years. Although it would be possible in principle to store gas (which has to be compressed for the gas engines anyway) and hence vary output, there are very few, if any, sites in the UK where this is done. This suggests that the capital cost would not justify it. However, it may be possible to allow gas to build up for a few hours within the site itself, then generate at a higher rate. When the generation plant is not operating, the gas is simply flared off. Most sites operate under NFFO with a guaranteed flat-rate price in which case there is no incentive to vary production. Some sites also provide heat so are classed as CHP schemes.

The availability of landfill gas is in the range 90-98%. A typical figure would be around 95%; newer plant is more reliable. With scheduled maintenance, it should be possible to achieve close to 100% availability, at fixed output, during periods without maintenance. Scheduling could therefore include limited storage, maintenance, and

'off'. Communications to these normally unmanned sites would be by powerline (i.e. via the network itself), SCADA or radio telephone.

6.5 Energy from waste

Energy from waste plants normally operate continuously, incinerating solid waste to drive steam turbines producing electricity and, in some cases, heat for buildings or industry. Most of the income is derived from 'gate fees' for disposal of waste. Some plants have supplementary gas firing which means output can be increased to match heat load or to produce more electricity at times of high pool prices. These sites are manned with sophisticated control systems, so it should be possible to include scheduling for distribution purposes at little additional cost. This could have a high value since such plant are normally connected at 33kV or 132kV in urban areas with high load densities.

6.6 Combined Heat and Power (CHP)

Combined Heat and Power (CHP) plant produces power, usually electricity, and useful heat. Only CHP plant producing electricity are considered here. The vast majority of plant is industrial, and the three largest plants are centrally-despatched. Only about 20% of sites export power, but these account for more than half the total capacity (i.e. tend to be larger plant). Exports from plant below 250 kWe account for less than 1% of exporting total capacity.

In terms of numbers, most plant is below 1MW, nearly all using gas-fuelled reciprocating engines. Most of the larger plant is steam or gas turbine. Numbers are dominated by small plant, while capacity is dominated by large plant; sites below 100kWe form half the number, but only contribute 1% of capacity, while the 5% by number of largest sites contribute 80% of the capacity. Around 7-8% of total UK CHP capacity is non-industrial[9], including community heating, hotels, leisure, hospitals, education, landfill gas and waste incineration.

The scope for growth of capacity in large plant is probably limited. Therefore, if a high rate of growth in CHP is achieved as the government would like, this is likely to come mainly from the small (up to about 100kW) to medium (up to a few MW) sectors of the market, which will be embedded in distribution networks.

6.6.1 Industrial CHP

Most large industrial plant is gas turbine, or steam turbines fuelled from coal, oil or industrial gases. These are used to provide electricity, heat and often absorption cooling. Most of this plant is sized to meet base heat load, and runs at full load throughout the year. In some cases there is no export. Some exporting gas plant shuts down overnight, or during the summer, if pool prices make it uneconomic to run. For most industrial plant, heat requirements for production or the industrial process is the principal determinant of available exports. Scheduling production is likely to take place at least 24 hours in advance, leaving limited scope for short-term scheduling for export purposes. Most of the profit from running this type of plant comes from the electricity generation, avoiding import and selling export, from November to May when pool prices are high.

It would be quite easy to arrange maintenance schedules to avoid periods when the embedded generation was needed. To a large extent this already happens, because long shutdowns are

avoided at times of high pool price. However, there is likely to be significant cost associated with starting up plant in terms of manpower and reduced life, and in some cases different fuels are required for start-up.

Overall, there would appear to be considerable scope for scheduling industrial CHP plant, or at least guaranteeing generation (export/displaced import) at given times with agreed scheduling arrangements. This will clearly need to be assessed on an individual basis. Most plant will already be carefully scheduled, primarily for production, and sites will be manned. It may be possible to add scheduling for DNO purposes, using existing procedures. At smaller sites the CHP unit itself may be unmanned, in which case additional communications will be required; the size of plant would probably justify a telephone link.

6.7   CHP for district heating and cooling

Although far less common than in northern Europe and Scandinavia, there are a number of urban district heating and generation schemes in the UK. The number is likely to increase as the government is favourably disposed towards new CHP plant. Domestic heating demand is much higher in the winter, and peaks in the early morning and evening. Commercial demand is highest in the morning but continues through working hours. Some systems also use absorption chillers to provide district cooling. Cooling demand is higher in summer and likely to be fairly constant during working hours, though with a year-round demand for many modern offices. Therefore its demand profile complements the heating profile well. Industrial heating demand using district heat will vary depending on the process but is generally higher in the winter.

Large-scale district heating schemes will serve a large diversity of users with no control over their demand patterns. Therefore heating or cooling must be supplied instantaneously from the system. Some other countries commonly use large central hot water tanks to buffer heating demand and decouple thermal demand from electrical demand. An example is Denmark, where CHP systems with thermal storage for domestic heating are widespread[10]. This allows a large proportion of CHP units to be turned off at night outside the coldest periods, and turned on and off to exploit high export prices. Systems are designed to meet at least 95% of annual demand for district heating. With storage, this can be achieved with a heat capacity of approximately 60% of maximum heat demand. To stop the CHP systems becoming base load producers, a three-rate export tariff was introduced in Denmark. This has a decisive effect on production profiles, in effect scheduling plant (for supply purposes) to match electricity demand.

Some schemes in the UK serving health, education and housing use thermal buffering in a similar way. Typically these operate at full load or off, using the thermal buffer to supply varying heat demand and exporting surplus electricity at times of higher pool price. Winter operation is about 17 hours/day, with little use for storage, but in other seasons plant runs until the store is full then turns off until it is run down. This results in it running for 8-12 hours/day, usually in 2-3 blocks of a few hours each. Examples include a scheme with 30kWe output for 40 flats, and another for 350 flats. Systems are usually operated locally but can be accessed and controlled remotely. By using a large temperature drop through the heating system the size of the thermal store is reduced in proportion. Thermal storage adds about 10% capital cost to small schemes, as little as 3% for large schemes, since the cost of storage per unit volume is much lower for larger tanks.

With a thermal buffer of several hours, there is plenty of scope to support a network for some time. However, output will normally be high at times of high demand, when there will be little scope to use them as supplementary generation.

All district CHP plant is already scheduled and remotely controlled to optimise output. Additional scheduling for distribution should not impose extra cost. The small increase in capital cost for storage will be justified by improved economics of operation. Income from distribution companies could be a useful additional income stream.

6.8   Domestic scale micro-CHP

Electricity generated by micro-CHP, using Stirling engine or solid oxide fuel cell technology, is likely to be available in the near future in the domestic/small commercial markets for own use and, where it exceeds demand, exported to the LV network for use in nearby homes[11].

In autumn, winter and spring the micro-CHP system would be run for heating and hot water. In summer, it may be switched off completely, or run for one or two short periods a day to provide hot water. At present, there is insufficient operating experience to know the most likely types of operation. If it was used during the summer, it would be available for network support provided the hot water tank was not fully heated. Present technologies are averse to being turned on and off, so will be designed to run for the longest possible periods.

Modern control and communication technologies allow optimisation of micro-CHP operation to minimise cost. Several distinct categories of scheduling can be envisaged for both trading arrangements and distribution purposes; some depend on the type of end-use. They include:

- Permanently beneficial demand shapes associated with particular classes of customer. Classes could potentially include low income customers such as members of a Housing Association or social group such as retired couples, or perhaps by business type, such as Restaurants.
- Day-ahead modification of demand profiles for supply or distribution purposes. Primarily associated with storage of hot water for subsequent space-heating, employing, once a day switching signals, based on predicted trading prices for the following 24 hour period.
- On-the-day modification of demand profiles, ranging from a few hours to seconds (including interruptible demand). Communications at relatively high bandwidth, and short notice, based on operational requirements in the balancing market or distribution system, potentially incorporating reserve capacity and frequency control.

The ability to control CHP operating profiles depends mainly on hot-water storage, and the ability of homes to absorb additional heating directly. Two types of generation capacity can be defined:

- Total (gross) generating capacity, including on-site use displacing import;
- Additional (net) generating capacity, excluding what would normally be generated anyway from micro-CHP systems.

A distribution company could request a micro-CHP system to run to support the network until the hot water tank reached its maximum temperature. The highest gross capacity

potential exists mainly during occupancy, and is lowest at night, which is usually favourable to distribution needs.

Eliminating times when the unit would be operating anyway, to give net capacity, gives very different profiles. Because the units are typically run during occupancy following high thermal demand when the tank is at a low temperature, elimination of this component greatly reduces capacity during occupancy. Storage potential is below 0.8h most of the time. It is most consistently high on cold winter nights and in the middle of the day in winter. With diversity of many units, there would be a distribution of individual storage potentials at any given time, so that most units would run initially then units would gradually switch off as the tanks became fully heated.

With a suitable optimising control system, it would be possible to increase storage potential on a day-ahead basis, by turning off the unit towards the end of occupancy so that the hot water in the tank was used up. One simple way of doing this would be to send cost messages to make it think that imported electricity very cheap at these times, so that it was uneconomic to run the CHP.

In most cases where storage is an essential element of load control, there may be a consumption cost associated with displacement of demand to other periods from losses during the storage period. With thermal buffering using a hot water tank, such displacement can be minimised. The capital cost of thermal storage is an additional cost about £150 per installation for a 210 litre tank, compared to around £1,000 for the micro-CHP unit (lower for a mass-market). Therefore storage represents about 10-15% of total cost. Financial benefits of storage, allowing a much higher proportion of electrical output to be used internally and at more expensive periods, would far outweigh any additional income from supporting distribution networks. To provide distribution support would require remote control via radio-teleswitch or similar. This would cost an estimated additional £50, unless such control was already incorporated as part of a CELECT-type system to optimise cost using day-ahead price information. It could also cost the company an estimated £250,000 to set up the communications system for BBC broadcast of signals.

6.9 Standby generators

The total capacity of reliably operable standby generation in the UK is estimated to be around 20GW, nearly all of which is driven by diesel engines. This is equivalent to nearly 40% of the England and Wales system peak, although of course only a very small fraction will ever be generating at the same time. Most plant is for large offices blocks, hospitals, supermarkets, and various installations where continuous power is important such as airports. Therefore most is in urban areas, particularly city and commercial centres. It is estimated that around 10% of plant exceeds 1MW, about 50% is in the 200kW-1MW range, and the remaining 40% is sub-200kW. Although it is growing, only a very small proportion is believed to be used regularly for peak lopping, the vast majority just being only for standby generation. Not all plant would be suitable for regular use, but this may only become apparent after testing. Standby plant could be run in two modes:

- On-site islanding - disconnecting all or part of the load from the mains, and connecting it to the generator(s). Some arrangements allow the generator to synchronise with the mains before transfer so that supply is continuous.

- Paralleling the generator(s) to the mains - if fitted with synchronisation and protection gear it can be synchronised and run in parallel to the mains without disconnecting load. When load is less than generation, the site will export power.

For supporting distribution systems, the second of these is preferable since the generator can run at full load and export, rather than just displacing the on-site load which will tend to be less than full output.

Costs of converting existing plant to export power when required are estimated at about £45/kWe for a 1MW plant under optimal conditions. Under the worst conditions, for example with long cable runs, difficult earthing etc. the cost could increase to about £120/kWe. Costs per kWe would be higher for smaller units. Older units would probably require an additional £25/kWe for emission control equipment, giving a total minimum cost of £145/kWe. These costs compare with up to £250/kWe for a new installation.

Minimal annual maintenance costs are estimated at about £1,200, for infrequent use, based on the cost of an inspection service, a major service and one hour test [12]. This cost would be fairly independent of engine size. Although servicing should be done anyway, this may not always be the case for standby operation only. Proper maintenance would be essential if plant was to be used to support the network. Alternatively, all-in maintenance with guarantees would be available for about 0.5p/kWh for dedicated plant. Total running cost including maintenance is about 3.5p/kWh.

By definition, standby plant is always available to run while there is power on the network. Therefore it is highly flexible for network support purposes. However, many building operators would consider than running in parallel to the network would increase the risk of losing power completely, so would be unwilling to allow this since reliable power is likely to be more highly valued than possible income from supporting the network. External factors such as noise and pollution may also limit use at some sites. In such cases infrequent use for distribution support may be acceptable, while frequent use at times of high pool price would not.

Assuming a total running cost of 3.5p/kWh and operating plant when the pool price exceeds this, a net income of around £60/kWe installed capacity can be generated (based on 1995 Pool prices; since then Pool prices have fallen significantly). This compares with the average of £10/kW/year which NGC pays for standing reserve.

Therefore potential income from unit sales are about six times higher than income as reserve capacity only (based on NGC payments). However, a generator could possibly offer both distribution and NGC support since at some sites it is unlikely they would coincide. There are no additional costs associated with providing distribution support, other than normal running costs, since the standby function would be unaffected. Indeed, regular maintenance and running would probably improve and demonstrate reliability for standby, so any additional income for network support would be seen as a bonus.

In many cases, several standby generators could be contracted to provide generation on request. This would give diversity and hence greatly increase the reliability of most of the load being available. Overall, this type of embedded generation would appear to be a very large and untapped resource for distribution companies, with positive benefits to the consumer. The largest barriers to use are likely to be:

- institutional barriers, such as convincing engineers within distribution companies that this will be an improvement on traditional solutions;

- confidence that running parallel will not compromise security of power to site
- problems of noise and pollution, particularly in residential areas with older plant.

7 Generator Reliability and Diversity

This section takes a brief look at the statistics of diversity and reliability.

7.1 Coincidence with peak load

By analogy with items of network equipment, the contribution to network security provided by embedded generators is often seen in terms of the availability of individual machines. It is true that a single generator is far less likely to be available than a transformer. Generator availability (assuming it is normally 'on') will typically be 85-95%, while a transformer typically has a 1% chance of failing once per year, implying an actual availability very close to 100%. However, this analysis is simplistic, firstly because a generator used to support a network will typically only be 'needed' when load is close to peak *and* one transformer of a pair has failed, and because when there are several generators the effective reliability improves dramatically.

Figure 2 shows the probability of the coincidence of one transformer failing, peak load day, and generator unavailable. Although there are many other reasons for network failure, this example does illustrate that a relatively low generator availability compared to that of network assets does not mean that the generator cannot reliably support a network. Communications would be needed, at the minimum giving the current status of the generator, but probably also some control to ensure it came on or stayed on when required.
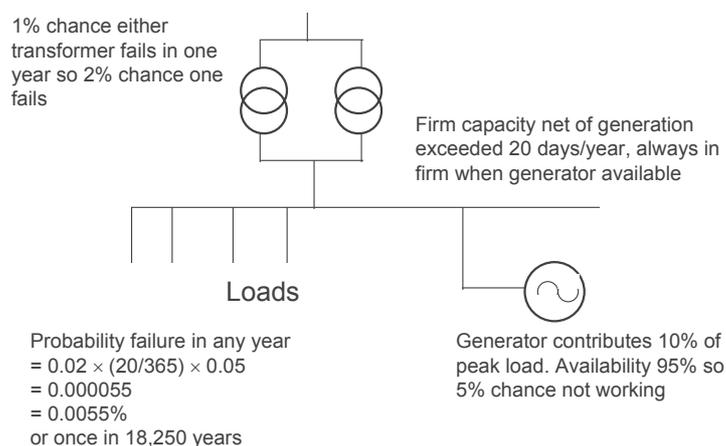

1% chance either transformer fails in one year so 2% chance one fails

Firm capacity net of generation exceeded 20 days/year, always in firm when generator available

Loads

Probability failure in any year
= 0.02 × (20/365) × 0.05
= 0.000055
= 0.0055%
or once in 18,250 years

Generator contributes 10% of peak load. Availability 95% so 5% chance not working

Figure 2: Probability of single generator failure when critical.

7.2 Diversity of several generators

Suppose there are 10 generators operating on part of a network, which normally run at full output. There are assumed to be no common modes of failure and generator availabilities are assumed independent. While the probability of a single one not operating is the availability (say 0.9), there is a high probability of some operating.

Figure 3 quantifies this (using the Binomial distribution) for different availabilities, plotting the probability against the proportion of capacity available. For example, at an availability of 0.85, there is about 0.53 probability of having 90% of capacity available, and about 0.82 probability of having 80% of capacity available. For 99% availability, 90% of capacity is almost guaranteed; probability is almost 1. (For comparison, the curve for 50% availability is shown; even here there is a probability of 0.95 of having a third of capacity available.)

For a DNO to have confidence in output from several generators, it would be necessary to collect output data over a period of time, and to know the status of generation when there was a fault; the analysis here merely demonstrates the potential.
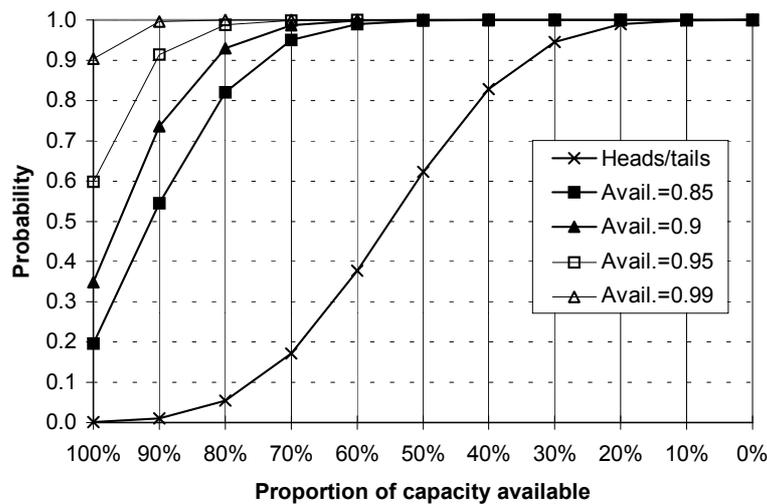

Figure 3: Probability of having different proportions of capacity availability from 10 generators with given availabilities

7.3   Diversity of a large population of small generators

The analysis can be extended to the case of many small generators, such as micro-CHP. Figure 4 shows the capacity curve for many generators with 98% availability (for times when they would normally operate). The expected capacity is about the same as the availability; there is almost no chance of all machines operating, but a probability of 0.99 of having 96.5% of capacity available. Therefore a DNO could plan on the basis that, say, 95% of capacity would always be available.
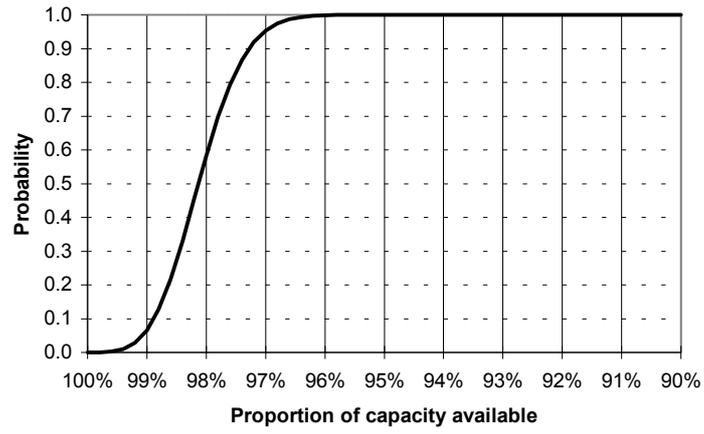
Figure 4: Capacity available from large number of small generators, with 98% availability

8 Communications for Embedded Generation, Automation and Customer Services

Communication for the remote control and monitoring of embedded generation and network parameters at distribution substations and customer premises, must take account of developments taking place in network automation and customer services areas. Embedded generation is predicted to reach 20% of market share by the year 2010 with a significant proportion of that being small scale, residential and small commercial customer systems. This is based on targets for CHP to increase by 8-10,000MW[13] and a target for renewables to reach 10% of electricity supplies by 2010 [14]

Developments are taking place to provide these customer groups with one way and two way communication capability for the provision of "Value Added Services". These services include energy demand management based on time of use pricing, supply on/off switching, security monitoring, elderly person medical alarm monitoring, remote diagnostics, as well as Internet access. Penetration of the target market is expected to be rapid over the period to 2010 driven by service provider companies as opposed to specific network or supply companies.

8.1 Provision of communications for embedded generation management

Communications systems for both outside and inside customer premises are being developed and implemented in trial quantities by major players around the world. These communication systems are for the implementation of customer services across a whole range of applications. Providing communication infrastructure for the implementation of individual services will be rarely cost effective. Consequently it makes technical and economic sense to consider the implementation of groups of related services. The groups of services, or 'service bundles', shown in Table 2 can be implemented using narrowband communication. They can also be implemented using wideband communication when this becomes cost effective. New applications and services will be continuously introduced to the market place and equipped with powerful Plug and Play capability in the communication protocols. This enables them to automatically link into customer "Intelligent Home" systems. Customer purchased and installed applications, such as remote diagnostics or energy audit of white goods include automatic installation tools which link them into the "intelligent home" communication systems. The customer gateway links the "intelligent home" communication system to the, external to the premises, communication network. Different communication media such as telephone, satellite, radio etc. will be available for use external to the premises and the selected option interfaced to the gateway. Different communication media and protocols such as powerline, radio etc. and LON, EHS, Bluetooth, etc, will be available for use internal to the premises and within individually controlled applications. The customer gateway is required to accommodate this range of technologies. Low cost flexibility in the customer gateway linking external and the internal to the home communication networks is essential for the development of future proofed, vibrant customer services markets using communications. Linking embedded generation management services into these systems will be relatively straightforward, based on the data exchanges and response times from Table 2.

Table 2: Summary of Capacity Requirements for Bundled Services

	Services bundle	Category of Service	Required data capacity (bits/second)
Customer	CA	Affinity deals*	200
Customer	CB	Energy data	200
Customer	CC	Energy management	1000
Customer	CD	Dynamic deals	1200
Government	GA	Energy saving	200
Network	NA	Network operation	1200
Network	NB	Supply monitoring	200
Network	NC	Energy provision	200
Supply	SA	Data collection and provision	1200
Supply	SB	Tariff/payment	1200
Supply	SC	Affinity deals	100,000

*Affinity deal - for example offering "air miles with energy purchases

More information on these service bundles is proided in section 9.5

Narrowband communication systems inside customer premises generally use the electricity mains wiring or twisted pair installed specifically for the purposes of communication. Pico cellular radio is being developed for these applications and is a serious competitor to traditional systems.

Narrowband networks are available for communication outside customer premises although their use is limited to date except for energy management and remote metering applications. Narrowband communication media include Public switched telephone networks (PSTN), narrowband radio or power line. These systems and their developments, when used for the provision of a range of services and applications, can provide cost effective solutions for the implementation of embedded generation management, identification of islanding and resynchronisation.

PSTN with high access levels to customers exist in most countries so that their use for utility services is attractive in terms of cost and time to implementation. Reading of remote meters, embedded generation management and other services can be carried out without ringing the telephone by means of special protocols. However the provision of broadcast functions for large numbers of customers such as switch on all generators, cannot be easily accommodated.

Low Voltage Distribution Line Carrier (DLC) Systems use the Low Voltage distribution network between the customer and the distribution substation as the communication medium. This medium has the major attraction for use as a communications medium for energy services and embedded generation management because it is available to all customers, is under the control of the electricity utility and already exists. It is also reasonably resistant to tampering and fraud. However, it is a hostile medium for communications. Broadcast messages can be readily accommodated as also can individual customer messages. Consideration would be required of the performance of this communication medium during adverse network conditions when it is likely to be needed.

Radio communication, involving cellular telephones, cellular unlicensed bands or even radio teleswitch can have a role to play in the management of embedded generation. These media are all being considered, or already used, for the provision of customer services. Essentially they are narrowband although developments of Global System for Mobiles (GSM)and third

generation radio, Universal Mobile Telecommunications System (UMTS) will provide wideband access in future. Radio teleswitch communication is very narrow band (22 bits/second) but is unidirectional. Radio communication has the valuable capability of being broadcast to many users simultaneously.

It is likely that one or more narrowband busses for communicating within customer premises will be the most cost effective way of implementing utility services in residential customers' homes in the foreseeable future. All illustration of a home bus including generation control is shown in Figure 5.
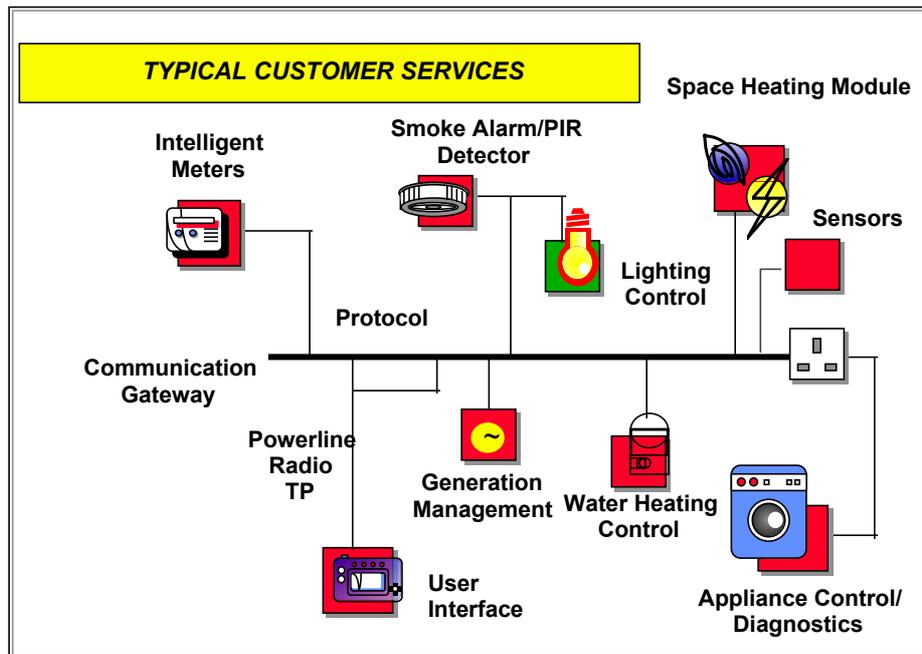

Figure 5: Typical Customer Services

Other sensors monitored in order to determine the availability of generation are connected to the same bus and shown in
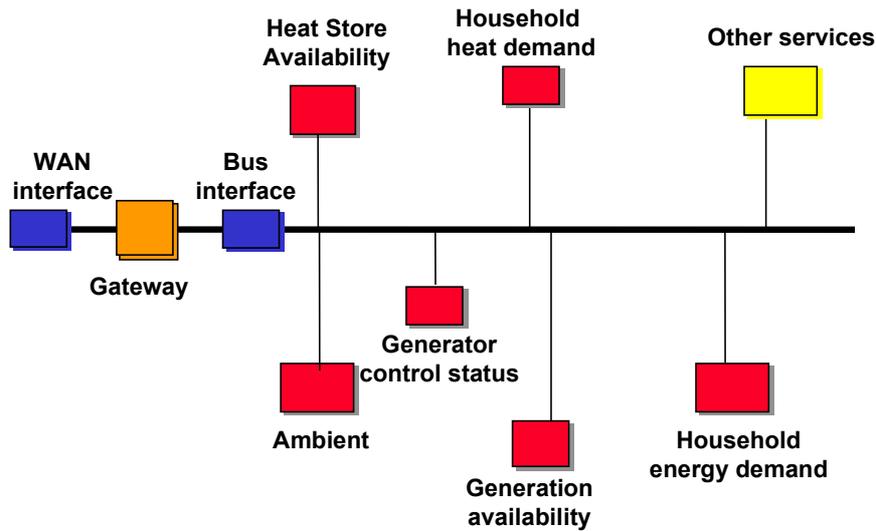
Figure 6.

Figure 6: Generation Management Control Bus

Irrespective of whether the "external to the home" communication medium used is wideband or narrowband, a narrowband gateway is required to link the external to the home communication medium to the narrowband customer bus. An illustration architecture linking external media including narrowband, Set Top Box or cable modem to the narrowband customer bus within the home is presented in Figure 7. Communication media for the "in house" bus or buses will be either pico cellular radio (Bluetooth) or powerline using the household ring main. Communication between managed devices and the outside world takes place through the Gateway which interfaces the different media and protocols. An architecture illustrating the Gateway, multiple service providers and multiple applications is shown in Figure 7.
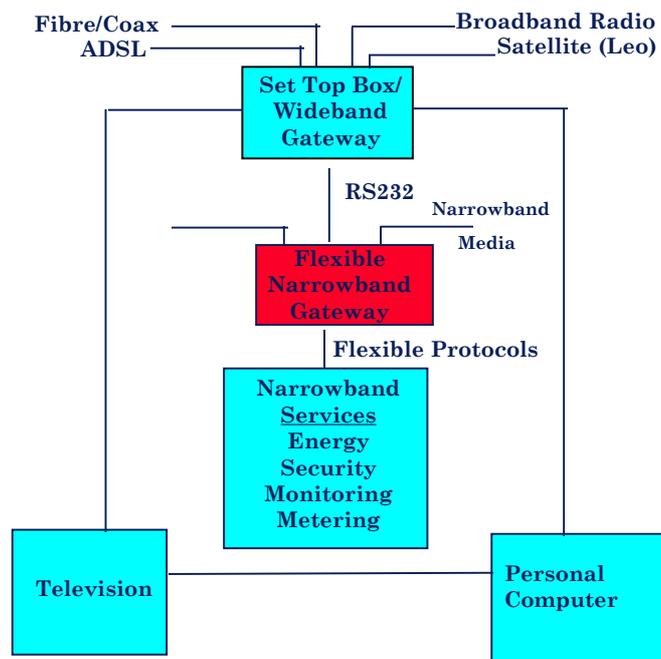

Figure 7: Customer Narrow & Wideband Media Architecture

9   Embedded Generation and Network Management

The majority of new CHP and renewable connections are likely to be at 11kV and below in the UK, with micro CHP at residential and small commercial customer premises on LV networks predicted to make a major impact. Most of these installations will use induction machines. Since such machines need to have reactive power supplied to them from an external source (the network in this case), they cannot run islanded (see Section 0). In any case protection equipment will have to be fitted as a connection requirement which will disconnect the generators when there is a fault.

There are issues associated with stranded network assets with the possible requirement for reduced network capacity and the certain requirement for reduced energy purchase. This can be regarded by network operators as a threat to their businesses, although it may also be an opportunity if the embedded capacity can be used as reliable firm capacity. Of particular concern in considering generation as firm capacity is the "black start" of networks containing significant embedded generation. Voltage quality issues resulting from significant quantities (>20%) of embedded generation are also of major concern to network operators. Conventional off load LV tap changers and 11kV level bar settings using AVC (automatic voltage control) relays may no longer produce adequate voltage control and accuracy.

Some of these issues can be alleviated or solved if reliable and cost effective communications are made available between embedded generators or blocks of generators, and network operation control rooms or primary substations.

Managing networks involving embedded generation and using strategies which obtain the maximum utilisation of all connected plant, both generation and network, will require communication for network automation, and remote control of 11 kV switchgear along feeders, voltage management and generation management. However these measures will significantly increase the complexity of network operation. With modern control rooms, improved facilities and the right financial and business drivers, networks involving significant quantities of embedded generation used in part as firm capacity, can be a technically viable option.

9.1   Embedded generation as firm capacity

Figure 8 illustrates a primary substation with a significant percentage of demand supplied by embedded generation connected to associated LV networks. If the transformer firm capacity at the primary substation is provided on the basis of excluding the generation capacity, then for loss of a single infeed on peak, the network capacity will be sufficient to meet the demand. For the loss of a double infeed and "black start", the additional load of many, small induction generators being started would need to be taken into account in determining the substation demand. Disconnection of the generation from the network as required by G59 and randomised timed reconnection following restoration of supply would alleviate this condition and enable the network to be restored by the restoration of one infeed.
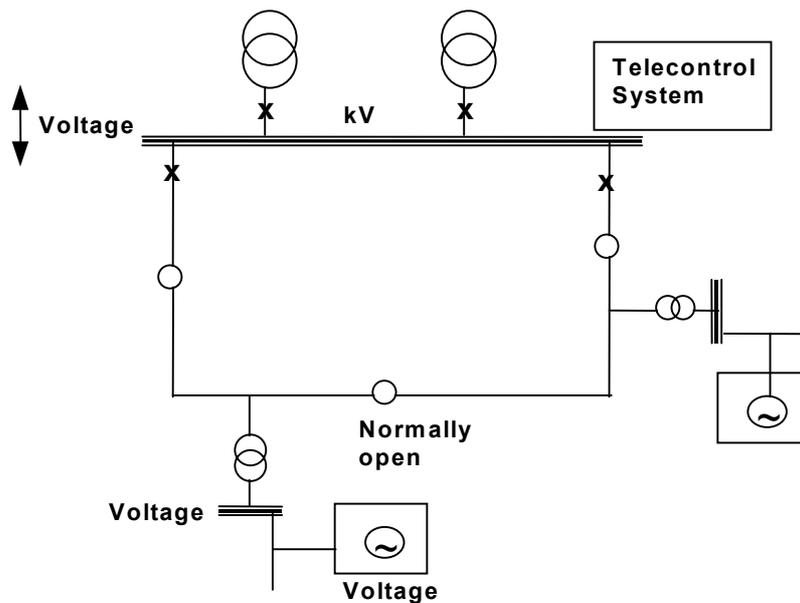
Figure 8: Embedded Generation / Firm Capacity

The more demanding conditions of using the multiplicity of small units of generation capacity reliably to support the primary substation firm capacity requires more careful analysis. In this situation, the primary substation is loaded above its nominal firm capacity, with the generation capacity excluded. In other words, the actual load on the primary substation is in excess of the transformer firm capacity at the substation. In this situation, the embedded generation is required to support the load in the event of a single infeed fault at peak. For this to be a viable option, it would be essential to ensure that sufficient generation was available, with a high degree of reliability, to meet the firm capacity requirements. This may involve generation status monitoring and control, although it could be assumed in many cases that a significant percentage of a large number of small generators would be operating on peak.

Under these loading and firm capacity conditions, the loss of a double infeed results in a situation where the restoration of both infeeds would be required in order to pick up all the load and also allow the generation to pick up. Staggered or delayed starting of generators would be beneficial to reduce network demand. However, there is not sufficient capacity available from the network to enable the restoration of a single infeed to pick up all the demand. In order to pick up demand with restoration of a single infeed, the 11kV feeders would be required to be opened, the infeed restored, and then the feeders closed individually on to the primary substation busbar. The generation associated with each feeder would be started after a time delay or by communication and then subsequent feeders closed until the substation demand, together with the generation, was totally restored. This scenario assumes that sufficient capacity exists in the 11kV feeders (which would generally be the case) and also in the LV network and substations (which would need to be designed for) to supply the demand and start up of the generation. Remote operation of primary substation 11kV circuit breakers is generally available via existing SCADA systems.

Micro CHP generation units are subject to delay in stopping and starting due to the necessity to dissipate heat prior to restarting and also due to a warm up period after starting before commencing generation. This could delay the restoration of supply. There are also disadvantages in terms of possible reduced generator life of allowing generators to overspeed by disconnecting them from the load. Consequently a preferred option for using these plants for the provision of firm capacity may be to devise methodologies to keep them running and

supplying a small local load but disconnected from the network after loss of supply. A method for synchronising them back on to the network following restoration would be required.

The reliability of firm capacity provided by aggregating and managing populations of small generators and the required more complex control of networks is an important issue. Depending on the types of generation and their uses, different quantities may or may not be connected when the network requires firm capacity support. Consequently, some ongoing estimate of the security of the network will be required and probably some arrangement to bring on additional generation if needed. An analysis of this management requirement in order to provide continuous firm capacity support, is beyond the scope of this report. Providing firm capacity by means of switching networks after faults and controlling and monitoring generation is likely to be less reliable than providing all the firm capacity by means of transformers at primary substations. However it may be reliable enough on the basis that primary substation, double infeed faults on peak are relatively rare and most small scale generation is likely to be operational during times of high network demand.

9.2   Voltage management

The issue of voltage management with significant penetration of embedded generation, is critical to network viability. Voltage management associated with induction generators can be a problem due to the variability of load and the operation of generators at different and varying locations across networks. The issue is whether LV transformers with fixed tap settings, together with dynamic tap changing at primary substations, will be sufficient to maintain statutory voltage at customers when generation and load patterns change. Communications between selected customers and primary substations could be used for providing an input of processed customer voltages to the voltage control relay at the primary substation to improve the profiling of voltage across a network. The use of dynamic LV tap changers, although costly, is also a possibility. These possibilities are illustrated in Figure 9.
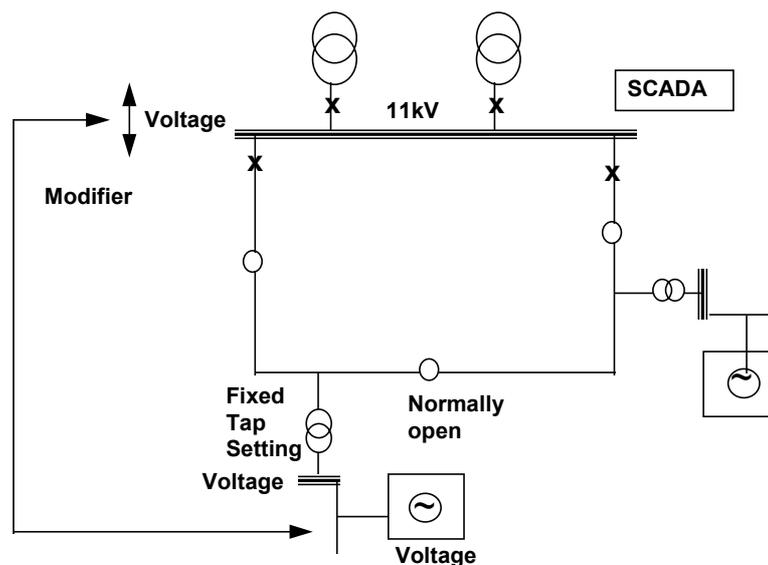
Figure 9: Embedded Generation / Voltage Management

The performance and behaviour of existing AVC (automatic voltage control) relays at primary substations would require evaluation if the export of LV and MV generation were to take place through primary substations to higher voltage levels. A directional element would probably be needed in the AVC relay to ensure stability.

9.3 Control of small scale induction generators

The majority of small scale embedded generators connected to MV and LV networks are likely to be of the induction design on the grounds of cost. There are limited control and monitoring possibilities available with these generators for management of network voltage and network support purposes. Monitoring of generator on/off status and availability, together with the ability to control that status, would be beneficial for network firm capacity support.

A generation management scenario can be considered where primary substation networks containing significant generation are continuously assessed for firm capacity. The reliability of that firm capacity based on the status and availability of the network and generation, would be quantified and evaluated together with some financial criteria. Reporting to control room staff, on an exception basis, where supply reliability was being jeopardised, could be an option.

The monitoring of customer voltage at selected points with and without embedded generation, can also be beneficial with the information being used as feedback to the primary substation voltage control relay to optimally manage customer voltage for all generator and load scenarios.

A summary of the control and status activities and estimates of the approximate response times required are listed below. These response time estimates are based on a balance between what may be reasonably required for operational purposes and what is achievable at modest cost.

9.4 Embedded generation management

Management could involve the following types of monitoring and control, with different access times:

- Monitor status (few minutes access time)
- Switch control (few minutes access time)
- Monitor voltage (2 minutes access time)
- Controlling voltage (2 minutes access time)
- Controlling status (few minutes access time)
- Sequential 11kV feeder switching for cold pick up (few minutes)

An important consideration in including more communication in the operation and management of distribution networks is the potential unreliability introduced. For example, it is essential that safe limits for voltage excursions are not dependent on communication being available 100% of the time. Communication must be used to provide fine control within a wider stable voltage band.

Similar considerations for the provision of firm capacity enhancements using communications must also be addressed. The reliability of supply through the concept of combinations of capacity is statistical. Including communication and network or generator switching adds another statistical variable. Quantification of supply reliability can be determined using the fault statistics, generator availability, network availability and the availability of control. This can be designed to provide acceptable levels of reliability.

9.5 Generation management within customer value added services

Providing enhanced customer services across a widening range of activities and the increasing customer focus of many utility businesses are features of the directions being taken in many developed countries. Consideration is being given to specific groups of services which could be provided by utility core businesses for the purposes of gaining competitive advantage, energy and network savings or quality of life improvements for their customers. This consideration generally relates to what the benefits are, who the beneficiaries of particular services are, the communication capacity necessary and the business case for their implementation.

Figure 10 illustrates the beneficiaries and potential drivers for the main energy related services, and therefore the potential investors in the infrastructure for their implementation.
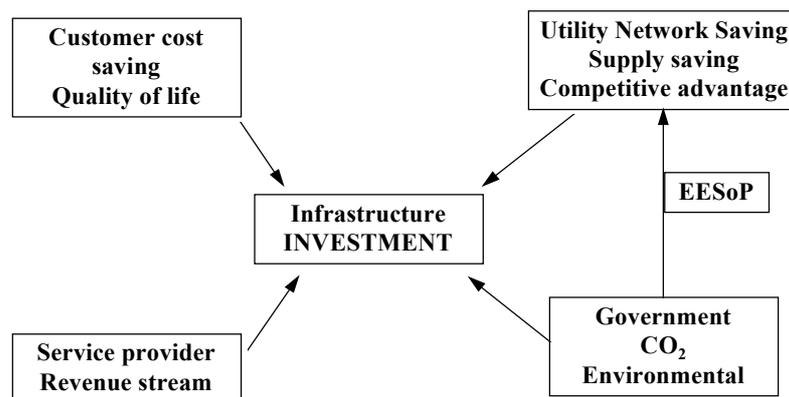

Figure 10: Drivers for investment in infrastructure

Section 8.1 shows a range of customer service bundles. These bundles include bundles CB, GA, NC and SA which have been specifically constructed to deal with energy services and provide benefits to customers in terms of comfort and savings, government (GA) in terms of environment, Network (NC) in terms of improving utilisation of capacity or reduced reinforcement and supply business (SA) in terms of improved competitive advantage. These bundles include estimates of the data exchanges needed to manage the services. One of these services is the management of embedded generation. A significant point about these service bundles is that they can be implemented using low data capacity, communication channels (200-1200 baud) and are being driven by requirements other than the provision of embedded generation management. Consequently, the incremental cost of adding an embedded generation management service to the bundle is low.

9.6 Network automation

Network and 11kV Feeder Automation is expected to be widespread by 2010 with normally open points on radial networks as well as mid feeder switches remotely and automatically controlled. Remote control of primary substation source circuit breakers is already widely available. The following schematic diagram,
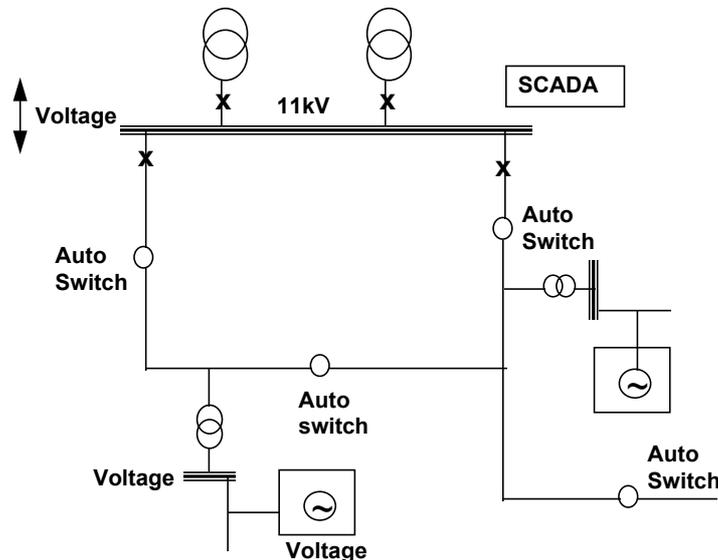Figure 11, illustrates this scenario.

Figure 11: Embedded Generation / Automation

Network automation can be regarded as a mechanism for reducing network operational costs, reducing customer minutes lost and as a means of providing switched firm capacity between primary substations. This switched capacity can be used in conjunction with embedded generation to provide mutual support in restoring supply.

This network control and managed customer services environment is the one that embedded generation will operate in over the next ten years. Many synergy's exist which can be exploited to achieve technical benefits and cost savings.

10 Metering and Commercial Conflicts

The following systems are used for >100kW demand customers who normally have half-hourly metering downloaded daily:

- Meters are normally read daily, with a maximum period of seven days allowed between readings. These are done by UK Data Collection Services (UKDCS) via PSTN lines or A packet switched (Paknet) radio modem.
- The modems are maintained by the meter operator. For historical reasons, Meter Operators tend to retain ownership and lease to the customer. Suitable modems cost the Meter Operator £50-60.
- Telephone lines, for similar reasons, tend to paid for by the Meter Operator and the cost passed on to the customer. Installation is £100, and line rental is £140 per annum.
- Paknet works on a slightly different mix of capital cost and rental cost but the net result is similar.

All suppliers who wish to be credited with non-pooled generation within a GSP are supposed to have half-hourly metering installed and submit data to the trading process[15]. This will operate in a similar manner to that described for demand customers, with the same costs. In practice many small generators have an agreement with their local electricity company to sell power at a fixed unit rate using non-half-hourly metering. It is not clear what will happen to this arrangement under NETA.

Half-hourly metering data is usually commercially sensitive and not available to third parties (i.e. it is between the generator and the supplier, or customer, they sell the power to). Continuous monitoring of output by the DNO would amount to half-hourly metering, which the generator and/or the purchaser may be unhappy to allow. Also, if the DNO had some control over generation there would be times when output was not optimised from a supply perspective. This could require some exchange of data, for example to quantify additional costs incurred by the generator or to prove that the generator operated as requested.

If metering data were considered too commercially sensitive to release to the DNO, alternative arrangements could include contracts which avoided detailed output data, for example giving the generator fixed limits to maximum (or minimum) output for a given period, or just giving output for times generation was requested, etc.

Where the generator is providing ancillary services which do not affect units exported, there should be no supply/distribution conflicts. Similarly, communications which enable more power to be exported, or generators to be brought back on line more quickly, will benefit the supplier and reduce exposure to imbalance on both the demand and supply sides. These uses do not have any metering implications. Furthermore, the separation of supply and distribution businesses means that the latter no longer have any vested interest in supply, and this should reduce the commercial sensitivity of output data.

While generators sell energy in a fairly transparent supply and demand market, they (and usually the DNO also) view use of the network in terms of a fixed contractual arrangement 'to export any amount, up to an agreed maximum, at any time'. Under present arrangements the generators is therefore mainly interested in maximising profit in supply and is unwilling to compromise this for network benefits which give him little in return.

A more market-based model of using the network, with for example constraints traded for higher output at other times, is however possible. This has already happened with telecommunications, where most of the costs are associated with running networks and the 'throughput' - information - is provided free by the customers. Governments are also beginning to treat transport systems in a similar way. DNOs are likely to take a more critical view of the returns on existing assets and new investment, as a result of regulatory pressures, which could lead to more targeted charging for use.

Charging generators for using the network, other than as at present paying only connection costs, is a highly contentious issue. One line of argument says that the network only exists to serve demand customers, so they should pay for all of it. On the other hand it could be argued, in simple supply and demand terms, that generators want to use it so should pay accordingly. This would generate an income stream for DNOs from generation which is currently lacking. It would provide an incentive for DNOs to connect generation for reasons of profit rather than simply obligation. If this happened, a range of innovative tariffs would probably emerge. The OFGEM working group on Embedded Generation Issues is currently exploring many of these possible arrangements. Because, like telecommunications, costs are strongly associated with peak demand, many export tariffs would be time or peak output

dependent and hence create a demand for more communications and control between distribution and generation.

11 Costs and Benefits

This section looks at a number of scenarios where scheduling could be of benefit, comparing value of benefits with the cost of communications and other costs, including:

- supply side benefits of scheduling and 'non-firm' capacity
- deferred or avoided reinforcement
- customer minutes lost (compared with costs of scheduling plant to reduce these)
- micro-CHP benefit of being able to operate if some comms/control considered essential

11.1 Deferred reinforcement

Faced with a substation at or nearing firm capacity with load growth expected, a company would normally replace or augment transformers to provide extra capacity. Increasing use of embedded generation introduces another option; to use embedded generators to provide reliable supplies to reduce peak load on the substation. Analysis of a hypothetical load growth scenario was carried out, comparing the costs of the two options.[16]. This assumed a time horizon of 10 years. For transformer replacement, figures of £100/kVA, £200/kVA and £400/kVA additional useful capacity were used. Discount rates of 4% and 6%, lower than the conventional 8%, are used to reflect current base rate prospects. For embedded generators to guarantee power, annual contract costs of £5/kVA, £10/kVA or £15/kVA were assumed, similar to maximum demand charges for large customers, and current NGC payments for standing reserve.

If there is indefinite deferment, savings were shown to be very high. Embedded generation support costs have a large impact when the reinforcement costs are £100/kVA, but less impact at £400/kVA.

- For the lowest £100/kVA additional capacity cost, savings (of 10% over 10 years) can only be made on the lowest £5/kVA support cost with the higher discount rate, the lower discount rate producing a loss.
- For the middle £200/kVA additional capacity cost, similar savings can be achieved on the middle £10/kVA support cost with the higher discount rate, the lower discount rate always producing a loss.
- For the high £400/kVA additional capacity cost, savings can be achieved on all support costs with both discount rates.

Overall, the results suggest there is potential for using embedded generation to defer reinforcement. As ever savings (if any) depend on the financial assumptions, in particular the cost of useful additional capacity and the annual cost of embedded generation support. The greatest savings would be achieved with indefinite deferment of new plant, which should be quite a viable prospect with increasing embedded generation. To implement such schemes, it will be necessary for the DNO to have confidence in the future of the embedded plant, and the reliability of its generation. Multiple generators would therefore be more attractive.

An investigation was carried out into the pattern of embedded generation by 2010, in terms of size, type and voltage connection level, and the effects on the network [17]. This took

projections for renewables and CHP for 2010, allocated them to voltage levels, and then allocated generation to transformers in typical 'lumps'. It was found that most of the generation was at 132kV and 33kV. Embedded generation can only defer substation reinforcement under the following conditions:

- substation at or near firm capacity
- growing load
- controllable generation for peak times
- multiple generators (say at least three) to provide security

Consider the 33kV level. For the first condition, in a typical REC network of 80 132/33kV substations, 10 might be expected to be at or approaching firm capacity over the next 10 years. With a total of around five 33kV new embedded generation sites projected for 2010, there might be perhaps one or two sites meeting all the criteria on an REC network.

Risk analysis is well established in many industries, but the electricity industry has tended to use design methods intended to eliminate risk as far as practical. This is changing as companies try to make their assets work harder. Analysing the risks of asset failure, including the effects and reliability of embedded generation which can add security (but also increase fault levels) is a fairly new area of interest for the distribution companies. Methodologies need to be developed to replace the present somewhat *ad hoc* approach.

11.2   Increased exports

A non-firm connection can result in increased exports overall. The lower line in Figure 12 shows the volume of exports which the network could handle (export potential) over a year on a firm connection with guaranteed minimal export. The upper line is the volume which could be exported on a non-firm connection. This is a real example from a UK distribution network. Note that although the non-firm connection allows slightly less export for a period in the late summer, for the rest of the year the potential export is about one third more with the non-firm option. Assuming an export price of £20/MWh, (80% of 1999 pool selling price) and a net increased export of up to 233GWh, the value of increased exports would be up to £4.6m. Even at a small margin this represents a lot of additional profit; the cost of scheduling arrangements which would be trivial in comparison with the gains.
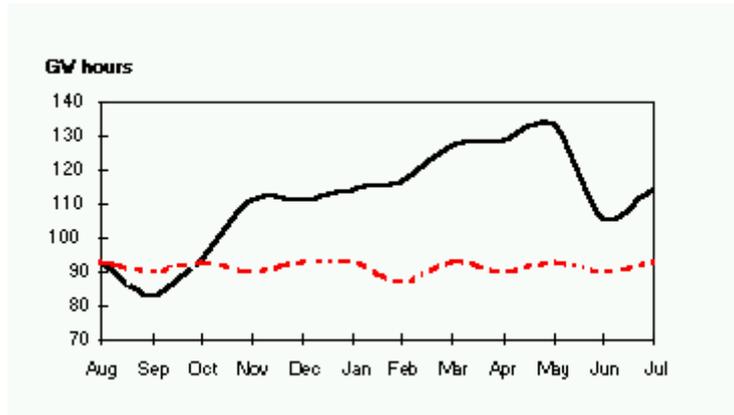
Figure 12: Export potential for firm connection (dashed line) and non-firm connection(solid line)

11.3 Value of avoiding customer interruptions

Suitable monitoring and scheduling arrangements could reduce or shorten power interruptions. A considerable amount of work has been done to assess the perceived cost of power interruptions to customers. These vary as a function of customer type, and the season, time of day and length of the interruption. There are various ways of measuring value, such as cost/kWh lost load, cost/kWh annual consumption, and cost/kW peak demand. From the point of view of the value of embedded generation, the cost/kW peak demand is the most useful (and is widely used elsewhere). The Sector Customer Damage Function (SCDF) for a given length of interruption is calculated by summing all the component groups' monetary costs and dividing this total cost by the total of the peak demands to obtain £/kW costs. Note that interruptions do not normally occur at the customer peaks, and these peaks do not coincide with each other. It is nevertheless a useful measure which avoids problems of simple averaging [18].

Table 3 gives the SCDFs for different customer types, from [19,20] updated to 1998 prices. This shows that commercial and industrial customers put a far higher cost on interruptions, particularly long ones, than domestic customers. As a result, even a small number of non-domestic customers can dominate the perceived cost of an interruption on a given section of network when SCDFs are used.

Table 3: Cost of interruptions of different lengths, per kW peak demand for different customer types

	SCDFs		(£/kW peak demand)				
Sector	Mom.	1 min	20 min	1 h	4 h	8 h	24 h
Residential	-	-	0.17	0.62	4.28	-	-
Commercial	1.14	1.17	4.47	12.24	44.87	90.4	114.92
Industrial	7.07	7.44	16.4	29.03	83.01	138.06	172.85
Large user	7.75	7.75	7.89	8.25	10.18	11.16	15.34

Consider a 132/33kV substation consisting of a pair of 60MW transformers, with a normal peak load of 60MW made up of 55MW domestic 5MW commercial customers. Then the cost of interruptions can be calculated by simply multiplying the peak for each customer type by its cost. The results are shown in Table 4.

Table 4: Perceived cost of interruptions for 55MW domestic, 5MW commercial load served by 132/33kV substation

	Cost	£000's					
Customer type	Mom.	1 min	20 min	1 h	4 h	8 h	24 h
Residential			9.4	34.1	235.4		
Commercial	5.7	5.9	22.4	61.2	224.4	452.0	574.6
TOTAL	5.7	5.9	31.7	95.3	459.8	452.0	574.6

Even with only 10% commercial customers, they dominate the costs. If embedded generation could be used to shorten interruptions through suitable control, the savings (as far as the customer is concerned) would be substantial. For example, shortening a 1 hour interruption to 20 minutes would 'save' £63,000, which is an order of magnitude greater than the cost of communications and control for a small number of generators connecting at the 33kV level.

Now consider a 33/11kV substation consisting of a pair of 20MW transformers, firm capacity 70MW, with a normal peak load of 15MW made up entirely of domestic customers at shown in Table 5

Table 5: Perceived cost of interruptions for 15MW domestic load served by a 33/11kV substation

	Cost	£000's	
Customer type	20 min	1 h	4 h
Residential	2.55	9.3	64.2

The savings here are much lower; about £6,000 for reducing a 1 hour interruption to 20 minutes, but still perhaps sufficient to justify more control of one or two local multi-MW embedded generators. If however support came from micro-CHP there would be many more generators. Suppose there were 15,000 customers (1kW peak load each) with 5% having micro-CHP, i.e. 750 machines. This would work out at about £8/machine for the saving described. In this case there would need to be other reasons to justify installing control and communications equipment; even a simple radio teleswitch costs about £50.

12 Dissemination

A free seminar entitled 'Scheduling Embedded Generation: Overcoming barriers to supporting distribution networks' was organised by EA Technology, and held on their site on 22 February 2000. It took the form of a series of presentations, followed by a workshop session in three groups addressing different issues. It was well attended, with nearly 50 delegates from a variety of organisations, the majority being from distribution companies. The presentations are given in the Appendix. Discussions and the outcome from workshop sessions are given here.

The discussions following the presentations and workshops are given in the Appendix.

13 Conclusions

At present, there is only limited application of scheduling embedded generation for distribution purposes in the UK. Usually, this was either to run dedicated plant to support

weak networks at certain times, or to constrain large generators such as CHP or wind farms to increase or, more usually, decrease output to help stressed networks. Some generators are able to export a lot more power on such non-firm connections than would be possible on a firm connection. Only a few examples of scheduling embedded generation were found in the literature for other countries. This is usually for an integrated supply and distribution utility, to balance demand with supply and to maintain network stability. Of particular current interest is accommodating the rapid growth of very variable wind generation within an existing generation mix, sometimes including CHP plant tied to heating requirements. Examples include autonomous island systems, where wind is competitive with expensive diesel generators and where the control problems are more difficult without a stabilising transmission system. Real examples show that integrated control systems are feasible with high levels of embedded generation. The separation of the supply and distribution businesses in the UK will make such an integrated approach more difficult, if not impossible.

Under NETA, it will become more important to predict and control output to avoid exposure to the imbalance market. This itself may justify control and communication of plant, but could also conflict with DNO requirements. Aggregators could negotiate deals with the local DNO using several plant. One of the most significant issues in NETA is that DNOs could be liable for constraint payments. One solution would be for generators who wanted a firm export connection to pay a standing charge for this, and then receive some form of constraint payments. Alternatively, connections would be non-firm and there would be no constraint payments. This would be consistent with the fact that generators do not pay for the distribution system beyond their own connection and any associated reinforcement.

The Government through the DTI is consulting on the growth of embedded generation on networks. They are aware of the need to revise the status of generation in network planning within Engineering Recommendation P2/5, and in particular want to "encourage distribution companies to manage actively embedded generation on networks, providing incentives for network security, real time monitoring of generation status and real time control of generation", suggesting they are likely to find room within NETA for such arrangements.

Most small generators are induction machines, which mean they import reactive power and therefore cannot operate without a 'live' network unless compensatory capacitors are installed, which can cause other problems. Large machines usually use synchronous generators which can provide both reactive power and frequency control, although DNOs normally rely on the NGC for these at present. The type of generator, combined with energy source and prime mover, determine what services can be offered through control and scheduling. Between the extremes of base load plant such as landfill gas which output at an approximately constant rate, and weather-dominated plant such as wind with quasi-random output, there is a 'middle ground' of CHP, dedicated plant and standby generation with the highest scheduling potential. All plant, however, can usefully be scheduled 'off' when required.

Control of embedded plant is likely to become important for network management, as the levels of both automatic control and embedded generation grow. On load restoration, there is the double problem of higher net load due to generators being off, and high starting currents for induction generators, possibly requiring staged reconnection and more control of when generators restart. Large numbers of small generators on the LV network, such as micro-CHP, would have significant effects on the management of load and voltage. Following loss of supply, load would increase significantly and machines could be off for a 30 minutes or more due to cooling and warming cycles. Start-up could also require very high initial

currents. If it were possible, with suitable communications, to keep generation running during a fault, these problems could be avoided.

Generation management could form part of a bundle of services for domestic customers, including security, appliance diagnostics, internet etc. at much lower cost than a dedicated system. Many of these could be implemented with cheap narrow-band communications at around 200 bits/second. For addressing many generators simultaneously, radio teleswitching is well established and very cheap, but of course only one-way. For communicating within customer premises, it is likely that one or more narrowband busses will be the most cost effective way of implementing utility services in the foreseeable future.

Half-hourly metering data, or equivalently continuous monitoring of generator output, is usually commercially sensitive information which the generator and/or the purchaser may be unhappy to give to a third party like the DNO. Any arrangements with the DNO will have to take this into account, by limiting the information accessed and finding commercial arrangements which satisfy both DNO and supplier needs. However, communication can also increase overall output and hasten restoration of supply.

Generator availability is considerably lower than the availability of network assets, but a full analysis shows that generation can still offer very reliable support. Essentially this is because it will usually only be required when part of the network has failed *and* load is close to peak, while many network components must operate continuously to maintain supply. When many generators are present, effective reliability is much higher (assuming failures are independent) due to diversity, such that a proportion of full output is almost guaranteed with several generators.

A complete cost/benefit analysis of scheduling embedded generation for DNO purposes is not practical, but some examples show that potential benefits can far outweigh the cost of communications. For example, for a large generator, a non-firm connection increased the potential value of exports by up to about £5.8m over the non-firm alternative. The value of avoiding interruptions, as assessed by customers, can be much higher than the typical costs associated with controlling embedded plant to avoid or shorten the interruptions. This is much more cost-effective at higher voltages with larger generators, and unlikely to justify the cost on its own for domestic-scale generation.

A free seminar entitled 'Scheduling Embedded Generation: Overcoming barriers to supporting distribution networks' was organised by EA Technology was well attended, with nearly 50 delegates from a variety of organisations, the majority being from distribution companies. The main concerns to arise from this were the implications of NETA, the effects of network failure, who controls generation, and the general technical problems of embedded generation. The overriding question was: who will take on responsibilities and risks, and who will reap the benefits? There was a feeling that DNOs could be in danger of picking up some of the risks without any clear benefits. Two views on more monitoring and control of embedded generation to benefit DNOs seemed to exist:

1. It is of little interest to DNOs under present arrangements
2. More active networks are inevitable, network automation will increase, and control over embedded generation can be used to benefit all parties within a suitable contractual and regulatory framework.

The experience of other countries which already have a high level of embedded generation suggest the latter outcome is more likely.

As further work, it would be useful to identify some new embedded generation schemes where active control for network benefit was desirable, and follow these through from planning to operation in the form of case studies

Appendix

This appendix describes the outcome of discussions during the free seminar entitled 'Scheduling Embedded Generation: Overcoming barriers to supporting distribution networks'

Discussions following presentations

Scheduling embedded generation for distribution - an overview
Andrew Wright, EA Technology Ltd
This talk gave an overview of the subject.
Q. Is 50MW BSC limit cast in stone for NETA?
A. No, still time for debate.

Case study - Scheduling on the NORWEB network
Steve Cox, NORWEB distribution
This talk described the management of large embedded generation on the NORWEB network, including use of generation for network support.
Q. What experience of large numbers of small generators during fault restoration?
A. Re-energisation is a problem as much higher levels of load are experienced - need to sequence reconnection in some areas.
Q. Should DNO allocate risks and penalties?
A. Ask Ofgem

Types of generator and constraints
Andrew Wright, EA Technology Ltd
This described different types of generator and their suitability for scheduling.
Comment: Problem is not so much generator reliability, more response to network failure - may need different protection to keep them running.
Comment: Transformer thermal inertia would give time for generators to come back on - transient high load OK.
Comment: need a vision for networks in 2010 - micro-CHP will have biggest impact.

Connecting to the network
Rob Driver, Econnect
This described how a more flexible approach to connection arrangements, such as varying maximum output allowed at different times, could benefit all players.
Q. Could you use voltage control at the generator to suit network constraints?
A. Have considered for wind, likely to be more problematic under NETA, need to see how new arrangements work.
Q. Why are you worried about DNO control of generators?

A. Not a problem for me [Econnect are consultants] but plant operators have supply contracts to honour.
Comment: Most constraints are more likely to be 'keep running' rather than 'stop', overcoming some of the commercial worries.
Comment: Under NETA the DNO carries the risk of constraining the output of a generator leading to exposure in the balancing market.
Comment: There is no incentive for DNO to take on these risks by connecting generation.
Comment: Ofgem must take initiative to sort this out.
A. Agree DNO has no incentive under current regulation to connect generation.

Communications methods
Richard Formby, EA Technology Ltd
This described the various types of communication system which could be used for controlling and monitoring generation.
Comment: Communications will help the DNOs control the network - offering many opportunities to control voltage etc. Interconnection offers benefits for embedded generation but has some costs and fault level problems.

Control of generation with the CUBE system
Oliver Qi, Orsi UK Ltd
This described a commercial system for controlling and monitoring large generation plant.
No questions.

In house communications
Richard Formby, EA Technology Ltd
&
Case study: Operating and scheduling domestic-scale micro-CHP
Russell Benstead, EA Technology Ltd
These talks gave an outline of domestic scale generation and the communication implications.
Q. What overall utilisation would you expect for micro CHP in a year?
A. Around 3,000 hours/year [~35%] 2-3 hours schedulable per day.
Q. What benefit for DNO? - surely main benefit to customer and supplier?
A. Main benefit avoided reinforcement.
Comment: Can see battle for control between suppliers and DNO.
Speaker comment: Can easily dump heat. May be able to detect scheduling needs by monitoring frequency and voltage.

Uses of scheduling on a distribution network
Peter Thomas, Manweb
This gave a description of the problems of generation on a distribution network, and some solutions using scheduling.
No questions.

Discussion groups
Delegates then split into three groups to discuss the following questions:
1. What would be the impact on network voltages of 20% demand from small embedded generators?

2. What would be the impact on network capacity of 20% demand from small embedded generators?
3. Who will manage and reward embedded generators for scheduling?

Outcomes from each group were as follows:

What would be the impact on network voltages of 20% demand from small embedded generators? (blue group, Richard Formby)
Voltage control will be a problem.
The 11kV network will be affected most.
Automatic Voltage Control instability is likely (some AVCs are designed to only operate for power flow in one direction 'down' the network).
Monitoring voltage will be important to achieve control.
For example on the 11kV/LV circuits, monitoring on customer premises will be important.

What would be the impact on network capacity of 20% demand from small embedded generators? (green group, Andrew Wright)
This partly depends on the nature of the generation -
♦ distributed or clumped?
♦ matched to load?
♦ LV or HV connection?
Important issues are:
♦ power quality
♦ voltage regulation
♦ fault level
♦ power factor/reactive demand
♦ phase unbalance
Possible solutions include:
♦ new switchgear
♦ splitting up the network (there is divided opinion here; some believe that more interconnection is needed to spread load, others think the network needs to be split more to avoid fault level problems)
♦ better control of load and generation
♦ heat and cold storage [for CHP]
♦ 'no export' control at a) customer point of supply b) LV source
There was a general feeling that generation would not make a useful contribution to capacity at LV but may do at 11 and 33kV. This partly depends on how the generation is distributed; if a whole new housing development has micro-CHP then net demand on the local substation could be reduced almost to zero at the system winter peak (it will be higher at other times when CHP units are not on), but if micro-CHP is scattered in say one in 20 houses, there would only be a ~5% reduction at the winter peak..

Who will manage and reward embedded generators for scheduling? (red group, Alan Creighton)
♦ little enthusiasm for scheduling at all from some
♦ if there are benefits people are happy that rewards are passed on
♦ an energy services company could gain benefits from control through aggregation
♦ there are conflicts with NETA
♦ generators should take on the responsibilities and get the rewards
♦ need to understand where the money to pay for the benefits actually comes from

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