Consideration of Proposed Changes to Small Scale Generation Connection to the Northern Ireland Electricity Distribution System

3rd September 2015
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# Abbreviations/Definitions

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<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>NIE</td>
<td>Northern Ireland Electricity Limited</td>
</tr>
<tr>
<td>SSG</td>
<td>A generator that is connected to the NIE distribution system either at low voltage or at 11kV.</td>
</tr>
<tr>
<td>Committed generation</td>
<td>Applications which have been offered and have accepted terms to permanently parallel to the NIE network to export electricity, reduce site demand, or both.</td>
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<tr>
<td>DNO</td>
<td>Distribution Network Operator</td>
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<tr>
<td>AGU</td>
<td>Aggregated Generator Unit</td>
</tr>
<tr>
<td>DSU</td>
<td>Demand Side Unit</td>
</tr>
<tr>
<td>UR</td>
<td>Northern Ireland Authority for Utility Regulation</td>
</tr>
<tr>
<td>UFU</td>
<td>Ulster Farmers Union</td>
</tr>
<tr>
<td>DETI</td>
<td>Department of Enterprise, Trade and Investment</td>
</tr>
<tr>
<td>DARD</td>
<td>Department of Agriculture and Rural Development</td>
</tr>
<tr>
<td>NIRIG</td>
<td>Northern Ireland Renewables Industry Group</td>
</tr>
<tr>
<td>CAFRE</td>
<td>College of Food, Agriculture and Rural Enterprise</td>
</tr>
<tr>
<td>ROC</td>
<td>Renewables Obligation Certificate</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>LIFO</td>
<td>Last In First Off</td>
</tr>
<tr>
<td>G83</td>
<td>Engineering Recommendation (ER) G83: EREC G83 is named “Recommendations for the Connection of Type Tested Small-scale Embedded Generators (Up to 16 A per Phase) in Parallel with Low-Voltage Distribution Systems.”</td>
</tr>
<tr>
<td>SEF</td>
<td>Northern Ireland Sustainable Energy Framework, published by DETI.</td>
</tr>
<tr>
<td>LCNF</td>
<td>Low Carbon Network Fund (available to UK DNOs, not available in NI)</td>
</tr>
<tr>
<td>MEC</td>
<td>Maximum Export Capacity; usually expressed in Kilowatts (kW)</td>
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</table>
1. The Consultation Process

1.1. Purpose of the consultation

Northern Ireland Electricity has produced this stakeholder consultation on the management of Small Scale Generation (SSG) connections seeking permanent parallel operation on the electricity distribution network.

The consultation is specifically written to seek stakeholder feedback on proposals for future ‘Managed Connections’ relating to SSG.

The demand for renewable SSG since April 2010, when increased ROC incentives were introduced by DETI, has given rise to a number of new and significant challenges. These relate to [1] arriving at workable connection methods and associated costs and [2] management of the distribution network, with significant levels of embedded renewable SSG, connected, committed to connect, or seeking to connect.

In addition to renewable SSG sources, non-renewable SSG can also export power to the distribution network in the form of Aggregated Generator Units (AGU’s). Therefore, operation of AGU’s must also be considered in this consultation.

Many areas of the distribution network have already reached saturation i.e. resulting in it becoming very expensive to connect in these locations due to local 11,000 volt (11kV) network reinforcement costs, or in some cases not possible to connect at all because of 33,000 volt (33kV) capacity constraints where the costs are not directly chargeable to developers and where the Competition Commission has deemed that such work is not in the public interest and therefore should not be funded by the general customer base.

The high level of demand for SSG connections combined with the relatively light loading on the distribution network means that the aggregated output of SSG has the potential to exceed customer load on the local network under certain conditions. If not managed appropriately, continued connection of additional generation, and/or the reduction of customer load as a result of on-site generation, can introduce significant risk of supply interruption and power quality issues for all customers connected to the distribution network.

NIE has been working to develop a high level approach with a number of stakeholders including developer’s representatives and the Utility Regulator to assess possible alternative connection arrangements, whereby the output of the generator is controlled in some way to avoid local network capacity limits being reached.

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1 Refer to Competition Commission ‘Final Determination’, sections 10.316 to 10.319.
https://assets.digital.cabinet-office.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf
It is considered appropriate to explore a pragmatic approach to further connection of both renewable and non-renewable SSG, which, while not unnecessarily deterring additional generation, ensures a safe, reliable and secure network for all electricity customers.

As part of this approach it is considered that to allow additional generation to exploit any remaining headroom that may arise due to the diversity impact of generators not achieving full outputs simultaneously, and the fluctuating load on the distribution system, the existing ‘passive’ distribution network which was designed for unidirectional power flow to electricity customers must now be developed to cater for the ‘active’ bi-directional, and often intermittent, power flows that exist as a result of SSG from both renewable and non-renewable generation.

This consultation\(^2\) sets out the background to the issues, provides a high level outline of a potential alternative ‘managed connection’ arrangement, and invites interested parties to submit views / answers to specific questions addressed in the document along with comments and evidence in response to these proposals.

1.2. Consultation period

The consultation will close for responses at 17:00 on Friday 16\(^{th}\) October 2015.

1.3. How to respond

Responses to this consultation should reach NIE on or before 17:00 on Friday 16\(^{th}\) October 2015, either by e-mail, to:

Chris.huntley@nie.co.uk

Or by post to:

Chris Huntley

Northern Ireland Electricity

Fortwilliam House

BELFAST

BT3 9JQ

\(^2\) It is expected that a separate, but related, consultation in relation to changes to NIE’s Statement Of Charges may also be carried out, in order to consider the treatment of costs associated with creating more potential headroom for SSG including any central control related costs relating to a managed connection arrangement.
1.4. Next steps

Based on the feedback to this consultation paper, NIE intend to publish final recommendations at the end of January 2016. The aim will be to have the new connections methodology in place by quarter 2, 2016.

It should be noted that the outcome of this consultation may have some dependency on a separate consultation relating to changes to NIE’s Statement of Changes, in order to assess how investment costs in establishing generator management functionality and any appropriate 33kV investment costs might be funded.

In general terms the following options need to be considered:

I. The investment costs being passed to the NI customer base.
II. The investment costs being passed developers.
III. The investment costs being initially underwritten by the general customer base and subsequently paid back by developers through some form of cost apportionment.
IV. The investment costs being met through a combination of i, ii & iii above.

2. Introduction

2.1. Background

Government commitment to renewable generation and the increased financial incentives introduced by DETI in April 2010 for Renewables Obligation Certificates (ROCs) has encouraged, and continues to encourage, applications for connection of renewable small scale generators to the NIE distribution system.

This unprecedented increase in activity has resulted in a rapid increase in SSG capacity since 2010, with over 270MW of renewable SSG, including single wind turbines, anaerobic digesters, hydro turbines and domestic solar PV micro-generation projects, now either connected or committed to connect to the NIE distribution network – see Figure 1. The vast majority of this generation is connecting at LV to the rural 11kV distribution network, leading to severe saturation as the distribution network has limited ability, or in some cases no ability, to cater for further generation without significant investment.

ROCs - The Northern Ireland Renewables Obligation (NIRO) is the main support mechanism for encouraging increased renewable electricity generation in Northern Ireland. It operates in tandem with the Renewables Obligations in Great Britain - the 'ROS' in Scotland and the 'RO' in England & Wales - in a UK-wide market for Renewables Obligation Certificates (ROCs) issued to generators under the Obligations.
In addition, other non-renewable generation is seeking permanent parallel operation in order to export to the distribution network or reduce site demand.

In effect, under the present connection arrangements, these renewable and non-renewable generators are competing for the limited capacity of the distribution network.

It is important to note that, under the present connection arrangements and from an overall transmission and distribution network operator viewpoint, both SONI and NIE have little or no control over when, if, or how much electricity is generated from these SSG sources, as they are non-dispatched, non-controlled and effectively self-regulating.

### 2.2. Project 40 – Supporting Renewable Connections

Project 40 was established by NIE in May 2014 as an initiative to support enabling of renewables connections in line with the Northern Ireland Strategic Energy Framework (SEF) 2020 targets for energy consumption from renewables in Northern Ireland, across both Large Scale Generation (LSG) and Small Scale Generation (SSG) including micro generation.

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**Progress to Date**

<table>
<thead>
<tr>
<th>Large Scale Generation</th>
<th>451 MW</th>
<th>517 MW</th>
<th>629 MW</th>
<th>647 MW*</th>
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<tr>
<td>+ 488 MW in delivery pipe</td>
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<tr>
<td>+ 42 MW with live offers</td>
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<tr>
<td>+ 160 MW at application</td>
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<table>
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<th>25 MW</th>
<th>41 MW</th>
<th>76 MW</th>
<th>109 MW*</th>
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<tbody>
<tr>
<td>+ 101 MW in delivery pipe</td>
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<table>
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<tr>
<th>Micro-Generation</th>
<th>&lt;1 MW</th>
<th>4 MW</th>
<th>45 MW</th>
<th>54 MW</th>
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<tbody>
<tr>
<td>+ 1.5 MW installed per month</td>
<td></td>
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</tbody>
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*Note some connections previously classed as LSG have been re-categorised to SSG

_LSG is now strictly ≥5MW_  
**Note – above not to scale**

**Position at end July 2015**

**Figure 1** – Graph showing the total quantum of Renewable Generation Connected since 2012
Project 40 was tasked with assessing UK best practice and considering a range of technical & commercial options to optimise network access and the delivery of renewable generation to the NIE network. Although the main focus of Project 40 relates to renewable generation, the implications of current grid saturation, and the potential introduction of an alternative “managed” connection arrangement, would equally apply to other non-renewable generation such as AGU’s and DSU’s. The remit of Project 40 is as follows:

- Explore a range of potential technical connection approaches
- Engage with UK DNO(S) to assess UK best practice – and to understand the potential application of approaches adopted by other DNO in the context of the unique constraints (including demographic differences) of the Northern Ireland network
- Develop commercial & technical models to aid the connection of renewable generation in a consistent manner.
- Consult with industry to agree the potential for these options and where applicable, establish appropriate rules and approaches in the connection of large scale, small scale and micro-generation to the NIE network.

2.3. Working Groups

NIE engaged initially with UK DNO, Electricity North West (ENW\textsuperscript{4}) to discuss a range of issues and scenarios and subsequently engaged with other UK DNOs as well as attending various forums including the ENA which are considering similar challenges to the connection of renewables. NIE intends to engage more widely as Project 40 progresses.

Project 40 established a number of working sub-groups comprising technical, commercial, financial and legal representation from NIE, together with representation from Industry, the Utility Regulator (UR), the Northern Ireland Renewables Industry Group (NIRIG), the Ulster Farmers Union (UFU), the Department of Enterprise Trade and Investment (DETI), the Department of Agriculture and Rural Development (DARD), the College of Agriculture Food and Rural Enterprise (CAFRE) and other stakeholders where appropriate.

This paper focuses on potential approaches considered by the Small Scale Generation Sub-group (Sub-group 1). This group is considering other methods for connection of additional small scale generation to the electricity distribution network.

\textsuperscript{4} Electricity North West owns operates and maintains the UK’s North West electricity distribution network, connecting 2.4 million properties, and more than 5 million people in the region to the National Grid.
3. Current Connection Methodology

3.1. A Network Perspective

Connection of distributed generation to NIE’s rural 11kV network is a particular area of growing concern as connected and committed generation levels have increased exponentially over the past few years. The rural 11kV network comprises around 20,000 km of overhead line (OHL). Sixty per cent of this network is single phase, mostly built in the 1950’s and 1960’s to bring electricity to rural homes, farms and communities. Seventy per cent of the OHL network is categorised as light construction 25mm$^2$ (cross sectional area) overhead line.

Historically, the distribution network was designed as a ‘passive’ network with unidirectional power flow from the Transmission system to the Distribution system to supply electricity to customers. With the connection of significant levels of SSG the distribution network now has dynamic bidirectional, and often intermittent, power flows which supply both load customers and flows from embedded SSG. When in operation, the physical output of embedded SSG supplies the local load customers first, with any excess flowing back to the 33kV distribution network and potentially to the Transmission network.

The existing distribution network was designed to cater for the maximum load flow at each point and is essentially a ‘passive’ network. The rural portion of this network supplies dispersed rural customers, being relatively lightly loaded and of relatively light construction when compared to other GB DNOs.

Whilst this network remains fit for purpose for ‘load’ customers, the specific features of light loading and light construction of the network does however limit the potential for connection of SSG. The light loading of the network means that a higher proportion of generation will flow back towards the primary substation and because of the light construction, in many cases the lines require reinforcement to avoid excessive voltage rise due to the exported generation. The situation is compounded further with the aggregated impact of a number of generators feeding back towards the primary substation causing thermal overloads on equipment at the primary substation and upstream 33kV network.

Furthermore, as SSG is self-regulating and not centrally controlled, dispatched or constrained, NIE has little control over when, or if, SSG is actually operational, particularly if generation is from intermittent renewable sources. Intervention to control generation output is therefore currently limited to operation of protection devices under abnormal system or generator conditions$^5$.

$^5$ Protection devices (G59 & G83) are designed to trip the generator under extreme operating conditions e.g. loss of mains, overvoltage, under-voltage, over-frequency, and under frequency,
While small levels of SSG, whose aggregated output is well below minimum load, can be more readily accommodated, the risk of supply continuity and power quality issues increases substantially as committed generation reach higher levels.

As a direct result of the uncontrolled nature of SSG, NIE must therefore assume that all connected and committed SSG can be in operation at the same time and assess the impact this aggregated generation has both at local circuit level and at the 33kV/11kV primary substation. To do otherwise, without an ability to control SSG output, would risk overloading the network, particularly during periods of low load and high generation output.

This necessary and critical assumption therefore limits the aggregated amount of SSG that can be accommodated safely on any distribution line, and at the associated 33kV/11kV primary substation, thereby any ‘diversity’ which may exist between actual SSG output and network load cannot at present be utilised.

When assessing SSG applications, and dealing with the technical issues that arise as a result of the generation, NIE must balance the risk of supply issues for all customers including 840,000 demand customers, against deterring additional generation unnecessarily.

The principle of the ‘managed connection’ is to allow additional generation connections to utilise any ‘diversity’ between generation output and load by controlling generation output when network limits have been reached. At present no technical or contractual arrangements are in place to permit this in Northern Ireland.

3.2.Current Connection Process

The current process for connecting SSG is to utilise the existing 11kV network infrastructure where appropriate. The SSG connection can either utilise an existing connection point or connect to a new connection point by extending the local 11kV infrastructure to provide supply to the generation site.

The main principle for the connection of SSG to the NIE network is currently based on a design that provides an applicant with a reasonable expectation of being able to export the output of their generator without constraint, under normal system operating conditions. For the purposes of this document, this type of connection is termed a ‘non-managed connection’.

While the technical analysis to assess a proposed SSG connection is complex, the primary aspects specific to the consideration of a ‘Managed Connection’ relate to:

(1) Reverse Power Flow - at the upstream 33kV/11kV Primary Substation: and

(2) Network Voltage Rise - on 11kV the lines/cables.
3.2.1. Reverse Power Flow

Traditionally, power flow was unidirectional from the power stations to the load demand. With the introduction of significant levels of embedded generating sources on the network, the direction and magnitude of power flows have changed. On the NIE 11kV network, as the output of distributed generation connected to any one circuit exceeds the load demand of that circuit, reverse power flow will occur. This reverse power flow will now be in an ‘upstream’ direction towards the associated 33kV/11kV primary substation and from there up onto the 33kV distribution network.

Each substation or other network component has an operational limit that determines the level of reverse power than can be accommodated. On the NIE ‘11kV Network Heat Map’, developed in 2013 to provide a visual representation of network congestion, we refer to substations being categorised as either ‘red’, ‘amber’ or ‘white’. Red relates to substations where the reverse power limits of the substation have been reached and no further generation can be connected; amber refers to substations that are approaching reverse power limits; and white refers to substations that have remaining reverse power capacity.

Factors that influence the amount of reverse power flow that can be accommodated upstream of the 11kV network include:

- Voltage control systems at the 33kV/11kV primary substation.
- Power transformer tap changer design and capabilities.
- Power transformer capability to handle reverse power
- Protection design
- The level of generation committed on the 33kV network e.g. large wind farms.
- Thermal limits of the upstream 33kV network

The cost to rectify these issues range from relatively low cost for new voltage control systems and tap changer replacements, to much larger costs if the substation transformers require to be replaced. In general, very much higher costs apply if upgrading of upstream 33kV lines is required. An investment of £2.3M was agreed between the UR and NIE in October 2013 for Network Reinforcement to c.40 Primary Substations which has to date released c.100 additional generator connection offers.

The current reverse power limitations have resulted in a figure approaching 400 offers or applications requiring to be withdrawn or deferred pending a possible solution to expedite any available headroom i.e. a ‘Managed Connection’, and/or further investment to enhance the reverse power capability at specific locations – see Appendix 1 - NIE statement on status of connection offers conditional on 33kV network reinforcement, 15th August 2014.

To deal with these reverse power issues, NIE has been considering, along with the Utility Regulator, a possible alternative connection arrangement whereby generator
connections are controlled to avoid network capacity limits being reached. This approach is in line with an alternative highlighted in the final determination of the Competition Commission on the NIE RP5 price control.

### 3.2.2. Network Voltage Rise

Export from any generation connected to the electricity network, regardless of whether the source is renewable or non-renewable, results in an increase to the voltage on the surrounding network. The higher the export from the generator, the higher the voltage rise will be. This voltage rise impacts the quality of supply for all customers connected to the network, not just the generator itself. The voltage rise on the distribution line must therefore be controlled to maintain supply quality and ensure network voltages are within statutory limits. The design of the generation connection may therefore include measures to limit the extent of the resultant voltage rise.

Issues that impacts voltage rise on the circuit include:

- The size and location of other ‘committed generation’ on a circuit
- The location of the new SSG on the circuit.
- The level of export from the new SSG seeking connection.
- The size and type of local network infrastructure in the area.

Following assessment of any SSG application, if voltage rise is not within permitted levels, the following mitigation measures are currently employed by NIE to achieve a technically acceptable solution:

- Upgrade the 11kV network by increasing conductor size (to reduce impedance)
- Upgrade the customer’s unique connection assets (to reduce impedance)
- Liaise with the developer to seek to reduce the generator rating and/or Maximum Export Capacity (MEC).

Where applicable, the 11kV network is reinforced to provide the connection capacity requested, the applicant paying the cost for all new works and any required reinforcement works to the existing network.

The impact of generation either already connected or committed on a circuit, to the connection costs for further applicants is of particular significance. As generation levels increase, the requirement for network upgrade to achieve acceptable voltage rise has driven connection costs to very high levels, severely impacting the financial viability of some projects. Many prospective connectees have had to substantially reduce export capacity in order to reduce their connection cost, others have had to abandon their project altogether.

In response to these increasing connection costs, NIE developed an ‘11kV Network Heat Map’ in 2013 along with a ‘Network Mapping Tool’ in 2014 to increase awareness of
areas where SSG connection costs were already high and where further SSG connections may no longer be financially viable.

Due to the self regulating and uncontrolled nature of existing SSG connections, connections must necessarily be designed to cater for the aggregated maximum generation output of all connected or committed generation at each circuit, and the resultant voltage rise on the circuit.

Initial work within Project 40 identified a principle which had potential to assist in dealing with the increasing cost of connection by removing the requirement for network rebuild, and managing the output of generators to control voltage rise on the network. The general principle is that by introducing local generator control, whereby the generator output is controlled to avoid network voltage limits being reached, any headroom or ‘diversity’ resulting from a difference in aggregated generation output and circuit load could be utilised to connect additional generation.

While the same general principle of utilising ‘diversity’ applies for Reverse Power Flow control, voltage control is primarily a method of controlling 11kV connection costs. In respect of reverse power, the requirement for 33kV investment is preventing other generation connections.

This document considers the viability of both ‘Reverse Power Control’ and Network Voltage Control’ generation management principles.

4. Consideration of a Managed Connection

4.1. The ‘Managed Connection’ Concept

What do we mean by ‘Managed Connection’?

To facilitate the connection of further generation to the network it is proposed to consider a more flexible connection approach based on a ‘managed connection’.

The development of a ‘managed connection’ to utilise any further available headroom on the network can be considered in two discrete elements, albeit if both were viable they might form part of an integrated control arrangement:

1. Reverse Power Control
   As outlined in section 3.2.1, this element relates to managing the extent of reverse power flow through the primary substation and upstream 33kV network, to safeguard the network against excursions outside specific network operational limits as an alternative to further significant 33kV level investment.
II. Voltage Control

As outlined in section 3.2.2, this element relates to managing the generator export at the connection point to maintain the voltage on the local 11kV network within specific limits – as an alternative to simply reinforcing the 11kV network through increased conductor upgrades at considerable expense.

Both elements require quite specific monitoring, control and communication arrangements.

While each of these elements attempts to expedite headroom, there is a need to explore their individual merits and viability including their technical feasibility. Factors to consider include

- the availability and maturity of the technology,
- the suitability of their application on the NI 11kV network (given some of the very specific NI factors of local population density / ‘scarcity’),
- the cost and practicality of implementation,
- the commercial viability for developers,
- the time required to implement one or both elements.

Each of these factors is considered in more detail below.

Initial scoping and research into DNO best practice in the UK suggests that controlling generation for reverse power is more likely to utilise existing technology i.e. directional load monitoring and central control systems. This level of control relies on a generator being able to accept and act on a signal from the network operator to reduce output to zero in a controlled and timely manner. This could be achievable utilising existing generator and substation technology together with reliable communications via a modified central control system. The volume of SSG connections to be managed would require an automated control arrangement with no manual intervention.

In respect of a voltage control solution however, the technology requirements are more complex, in particular controlling the real power and reactive power components of individual generators according to an applied voltage set-point and fluctuating network operational voltages. This requires significant additional control equipment on the NIE substation and generator side to facilitate the required generator self-controlling functionality.

NIE has conducted a substantial network analysis to explore the relative merits of both aspects of control. These are discussed in detail in section 4.4 below.

4.2. Suitability of the NI Network

Settlement patterns in and levels of industrial development rural areas of Northern Ireland are different than in England, Scotland and Wales, in that the rural population tends to be scattered across a comparatively wide geographical area, rather than
clustering in hamlets and villages as in Great Britain. Furthermore in general Northern Ireland is ‘more rural’ than Great Britain.\(^6\)

The NIE rural 11kV network therefore differs significantly from the majority of the UK networks in a number of ways. The most significant differences have evolved due to the rural 11kV network in NI supplying much lower than average customer densities, when compared with the UK, largely due to this dispersed nature of habitation in rural Northern Ireland and lower levels of industrial development.

This has resulted in a rural network in Northern Ireland evolving to have a higher than average ratio of radial spur line to mainline, comprising lower than average capacity small cross section conductors, and longer overhead line circuits with significantly lower peak and minimum circuit loads.

In general terms typical minimum loads in UK DNO rural networks seem to be typically around 4 to 5 times those on the NIE’s 11kV network. Similarly, typical peak loads are 3 to 4 times greater respectively. The impact of this is that the local ‘load sink’ for generation is often much smaller by comparison with similar UK DNO networks, resulting in generation output in NI being pushed further up the network where it impacts on the 33kV network, for example, in respect of reverse power flow.

The primary requirement, to safeguard the network and existing customer connections, is therefore to control the level of reverse power by constraining generators output at particular times.

**4.3. Research & Network Analysis**

In consideration of alternate connection arrangements for small scale generation, NIE sought views and experience at varying levels from a number of UK DNOs. In addition NIE commissioned a detailed independent study of the NIE network by Smarter Grid Solutions Ltd to consider the ‘Potential Application of Active Network Management to Enable Small Scale Renewables’ (published in April 2014).

Furthermore, NIE has performed significant additional in-house network analysis across a large sample of the 11kV network to understand the level of additional headroom that might be utilised under the ‘managed connection’ approach.

**4.3.1. DNO Experience**

NIE and UK DNO ENW met on a number of occasions to confer in detail on a range of items relating to the connection of renewable generation. NIE specifically sought views

\(^6\) The Department for Social Development (DSD, 2008) classifies 32% of Northern Ireland households as ‘rural’ while the Expenditure and Food Survey classifies 21% of Great Britain households as rural (ONS, 2008).
from ENW on their views and experience with managed connections from both a voltage control and reverse power control perspective.

Salient differences in network composition and load concentrations, referred to in section 4.2 above, specifically shorter thicker circuits and higher peak and minimum load, means that ENW have little concern over reverse power to the upstream network. In addition locational charging mechanisms encourage generation to locate close to the source negating the need for any elaborate voltage control systems to offset expensive network reinforcement.

Through discussions with the Electricity Network Association, and more specifically with UK DNOs SSE Scottish Hydro, SP Energy Networks Central & Southern Scotland, UK Power Networks and WPD, this theme seems to be a common feature with most UK DNOs.

Direct discussion with the DNOs referred to above, particularly Scottish Hydro whose network is most similar in structure to the NIE network, revealed no specific experience with managed small scale generators. Scottish and Southern did have some limited experience of managed connections in the context of large scale hydro generation with capacities in excess of 7MW, and UK Power Networks have been trialling similar technology to control a small number of individual generators (above 500kW) as part of their ‘Flexible Plug and Play’ project.

In general the DNOs had reservations as to whether this type of control would be practical or viable for lower levels of small scale generation below several MW capacities. Any proposed rollout of managed connections for small scale generation is an ambitious goal, and requires careful consideration and assessment through a working field pilot.

4.3.2. Smarter Grid Solutions Study

NIE asked Smarter Grid Solutions (SGS) to perform network studies in order to determine if Active Network Management (ANM) controlled connections presents a suitable alternative to reinforcement and would more fully utilise existing network capacity. Studies were performed to explore power system problems (i.e. thermal and voltage constraints) in the studied networks and provide an indication of the level of generation that might connect while accepting a level of curtailment.

The feasibility of using ANM, or the scope to connect new ANM-controlled generation, can be inferred from the capacity factor that is achieved after curtailment. As more generation connects it is necessary to curtail more of its energy production and the capacity factor is reduced. Feasibility has been assessed in terms of an “acceptable” capacity factor.
The studies incrementally added 0.1MW of generation to fixed positions at the middle and end of the circuits studied, and determined the impact of each subsequent connection on the capacity factor. As expected, the analysis confirms that generation at the end of the circuits makes the voltage rise problem worse than generation at the middle of the circuit. The results suggested that with a level of constraint of 10%, additional connection of generation of between 0.2mW and 0.48mW might be feasible on a typical 11kV circuit. However, this varies considerably according to circuit length and conductor type (i.e. impedance).

The final report, published in April 2014, therefore concluded that on 11 kV circuits with voltage constraints, while the feasible capacity will depend on the circumstances of each circuit and the generators seeking connection, ANM is likely to enable only limited connection of additional generation utilising voltage control, but significantly more utilising reverse power control.

### 4.3.3. NIE Network Analysis

More recently, specific to the Project 40 investigation into the feasibility of the ‘managed connection’, NIE performed significant additional in-house network analysis across a larger sample of the 11kV network.

15% of NIE’s rural 11kV network was analysed to understand the level of additional generation that might be available to connect to the network under both:

- a) Reverse Power Control, and;
- b) Voltage Control

The sampled network was categorised in line with the NIE 11kV Network Heat Map, with substations and areas (groups of circuits) represented across the range of substation and circuit categories i.e. Red, amber and white.

#### 4.3.3.1. Reverse Power Control

The reverse power capacity of any primary substation is equal to:

- the minimum load on the substation, where a substation has no reverse power capability, or;
- the minimum load on the substation plus the reverse power flow limit, where a substation has a level of reverse power capability.

At any point in time, any additional generation capacity is therefore the difference between the connected/committed generation and the reverse power capacity. Any reverse power control system must therefore act to constrain generation at particular times to ensure that the level of reverse power never exceeds the reverse power capability.

In consideration of generators connecting to this network, while being controlled to limit reverse power, following discussion with the renewable industry two levels of required generator ‘availability’ were considered, 90% and 80% respectively. So in
effect the analysis considered the level of additional generation capacity that could be connected if, by controlling generation to within the required reverse power limits, the output of the additional generation was constrained by:

a) a maximum of 10% (equivalent to 90% availability), and;

b) a maximum of 20% (equivalent to 80% availability).

The results of the analysis of substations sampled in both heavily saturated and less saturated areas, outlining the average generation capacity potentially released are shown in Figure 2 & 3 below. In all cases any existing connected/committed generation is considered to be non-constrained and operating at full output.

<table>
<thead>
<tr>
<th>Station Colour</th>
<th>% of stations where additional generation can be connected</th>
<th>Average Generation Capacity (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Red</td>
<td>20%</td>
<td>400</td>
</tr>
<tr>
<td>Amber</td>
<td>100%</td>
<td>490</td>
</tr>
<tr>
<td>White</td>
<td>100%</td>
<td>625</td>
</tr>
</tbody>
</table>

**Figure 2 – Generation capacity released, 10% Constraint**

Note: a 10% constraint means restriction may apply up to 10% of the time.

<table>
<thead>
<tr>
<th>Station Colour Code</th>
<th>% of stations where additional generation can be connected</th>
<th>Average Generation Capacity (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Red</td>
<td>53%</td>
<td>450</td>
</tr>
<tr>
<td>Amber</td>
<td>100%</td>
<td>830</td>
</tr>
<tr>
<td>White</td>
<td>100%</td>
<td>865</td>
</tr>
</tbody>
</table>

**Figure 3 – Generation capacity released, 20% Constraint**

Note: a 20% constraint means restriction may apply up to 20% of the time.

So from Figure 2 it can be seen that if the maximum constraint on additional connected generation is limited to 10%, then additional generation can be connected at only 20% of ‘red’ substations, with an average of 400kW of additional headroom available at these substations. In respect of both amber and white substations, 100% of the substations studied would have additional available headroom of on average 490kW and 625kW respectively.

When we consider the maximum constraint on connected generation at 20%, as illustrated in Figure 3, then additional generation can be connected at 53% of ‘red’ substations, with an average of 450kW of additional headroom available at these
substations. Again, in respect of both amber and white substations, 100% of the substations studied would have available headroom, increasing on average to 830kW and 865kW respectively.

For specific substations it may be possible to further increase this headroom by investing to increase the reverse power capacity at a particular location. Section 3.2.1 outlines the factors that influence the amount of reverse power flow that can be accommodated upstream of the 11kV network where investment might be focussed.

The benefit of any such investment is very specific to a particular location. As such, the above analysis does not take account of additional headroom that may achievable through specific further investment.

4.3.3.2. Voltage Control

Under the existing connection arrangements, connected generation is permitted to run at full output and the voltage rise requirements are catered for by the connection design, including any requirement for system reinforcement.

Investigations into voltage control showed that to govern a generator by limiting the generator voltage output based on a set-point requires very complex control, both for NIE’s and for the customers’ generator control systems. Due to the fluctuating nature of the NIE network voltage under normal operation, the voltage set-point at any generator installation would need to dynamically model the network voltage at the connecting substation and adjust the voltage set-point in real time. Findings from other DNO’s confirm that voltage control has not been implemented due to its complexity and subsequent high perceived cost.

Furthermore, in consideration of voltage control, the characteristics of the 11kV network, as outlined above, becomes a very significant factor and impacts hugely on the additional level of constraint that would be applied to generators connected in this way.

4.4. Complementary power sources and demand matching

The managed connection attempts to utilise network headroom, albeit with potential to constrain generators under specific network conditions. To further increase the penetration of small scale renewables and minimise the impact of any constraint, it is appropriate for developers to consider the viability of combining complimentary renewable generation sources in a way that increases the overall capacity factor of a renewable power plant.

For example, electricity produced from solar energy could be a counterbalance to fluctuating wind generation. It tends to be windier at night and during cloudy or stormy weather, so there is likely to be more sun-shine, and therefore more solar energy, when there is less wind. By combining sources to increase the capacity factor it may also be appropriate to reduce the combined MEC to avail of a cheaper connection.
More complex solutions might utilise generation from other sources like biogas or where practical hydro, with the potential to increase the capacity factor further by adding storage and/or by varying load according to available generation. Furthermore, through diversification, any new on-site load could avail of generation output.

In theory, a power plant combining different renewable sources could be coupled with energy storage and load/process control to provide load-following power around the clock, entirely from renewable sources.

4.5. Concluding the ‘Managed Connection’

Albeit the GB DNOs have availed of a sizable research fund via the Low Carbon Network Fund (LCNF); our own evaluation, including site visits to parties considered at the forefront of innovation, suggests there to be little or no experience of a voltage managed solution for small scale generation applications similar to those being considered here and therefore any such solution, even if were to afford significant benefits in terms of reducing connection costs, is likely to take a substantial time to establish.

Aside from the complex control requirements, our analysis which combines work commissioned externally last year prior to Project 40, suggests managing reverse power is likely to provide the best opportunity to utilise any significant headroom. Regardless of the immaturity of the technology, adding a voltage control option would further add to any level of constraint imposed from reverse power management, and (again based on our analysis) is likely to be beneficial to only a small number of sites.

While there may be a case for considering a voltage management pilot at some future time, early signs from the analysis would suggest quite low levels of additional access to the network would be achieved through this method of connection. This, coupled with the shortfall of any suitable proven technology solution (i.e. an off the shelf product), and a relatively short available timeline before changes in the ROCs incentives model, points to the overall viability of this element of a control solution in the short term being highly questionable.

In the absence of any proven technology in this area, the time and cost requirements to develop a workable solution, and the limited suitability for application to the NIE network lead to conclude that Voltage Control is not a viable option.

This consultation will therefore focus on a ‘managed connection’ based solely on the management of reverse power.

5. Reverse Power Management

Where the total generation connected to a specific 33/11kV primary substation exceeds the available load at that substation at any point in time reverse power flows back up though the primary substation to the upstream 33kV network. These power flows,
referred to as ‘Reverse Power’ may result in specific network operational limits being exceeded.

In certain cases the substation and upstream network will be capable of accepting a level of reverse power (some of which are illustrated on the NIE Heat Map as white or amber substations); in others no reverse power can be accommodated (illustrated on the NIE Heat Map as red substations). In addition, 33kV network investment to replace or upgrade specific network components may increase the level of acceptable reverse power at specific locations, although the issue remains as to how these 33kV investment costs should be allocated.

As network load and aggregated generation output are variable, there may be potential to connect additional generation to the network to utilise the headroom that results at times when the aggregated generation output is lower than the reverse power capability of the specific network. However, when generation output approaches the acceptable level of reverse power, it is necessary to be able to control the aggregated generation output to within these limits. This is known as ‘Reverse Power Control’.

The basic concept of Reverse Power Control therefore relies on controlling the reverse power flow through the primary substation, to avoid the 33/11kV primary substation reverse power flow limit or any upstream network limits being exceeded. The control function would at times require generators outputs being reduced to zero in a controlled manner to protect the network from any excursions outside these network imposed limits. This central control would be based on ensuring predefined limits for the transformers and associated equipment, or the upstream network, are not exceeded. The sequence of generator disconnection would be in a pre-defined order, options for which are described in sections 6.1 and 6.2.

The level of the constraint applied to the generator would therefore depend on the following elements

- The load profile of the connecting circuit and upstream primary substation
- The level of connected generation on the connecting circuit and upstream primary substation
- The reverse power flow limitations at the connecting primary substation e.g. 33/11kV transformer; or, where the upstream 33kV network limitations impose a more onerous constraint, the reverse power flow limitations of that network (including N-1 limitations7).

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7 The Network Planning Standard that specifies the minimum level of supply security that the distribution networks must achieve. The standard generally requires the 33kV network to maintain supplies under N-1 contingency i.e. for the loss of 1 circuit through a planned or unplanned (fault) outage. The level of reverse power capacity at a particular location needs to take account the impact of N-1 conditions.
Managing connections on the basis of reverse power management only will still require
reinforcement of the local 11kV network to maintain statutory voltages on the network.

It should be noted that additional costs may also apply if specific control and
communication arrangements are required to managed reverse power. More details
are provided in section 6. This may be of particular significance to smaller installations
as additional costs may affect the financial viability of smaller projects.

To assist in the decision making process the following will be made available to an
applicant

- Heat map – providing indication of congestion in the sought location
- Network mapping tool
- Typical annual half hour load profile of the connecting 33/11kV substation
- Where appropriate and where information is already in the public domain, a
  high level view of the existing connected and committed generation
  connections e.g. summation of capacity by generic generator type.
- An estimate of the current applicable constraint relating to the reverse power
  flow limits of the connecting 33/11kV substation and upstream 33kV network.

The prospective generator applicant would themselves be required to carry out the
appropriate analytical assessment to determine the likely level of constraint by
combining the constraint information which NIE is positioned to provide alongside their
own generator specific information to arrive at an overall impact. This will allow the
prospective generator applicant to understand how the constraints will impact the
applicants own business case.

It is likely that depending on the balance between load on the circuit and the
aggregated connected/committed generation and the specific technologies making up
this connected/committed generation, that future ‘managed connection’ type
generators will view constraint risks in different ways.

As an example, if the connected/committed generation at a substation consists
primarily of wind turbines, then any developer wishing to connect additional wind
turbines to that substation may assess constraint risk as very high. This is because all
the wind generation will be competing for capacity at the same time i.e. when the wind
is blowing. In the same circumstances, a developer of PV systems may consider the risk
as low outside high wind periods and hence acceptable overall.

The mix of generation is therefore critical to the assessment by the generator
developers of the likelihood of actual constraint occurring.

5.1. ‘Managed Connection’ Principles

It is proposed that the introduction of the managed connection will only apply to new
generator connections after an agreed ‘implementation date’.

Northern Ireland Electricity
Project 40
Small Scale Generation Connection
The approach for connecting generators to the network under the reverse power managed connection is similar to the current method where the developer pays for any 11kV network reinforcement required to maintain the voltage within the imposed design limits. However in addition the developer will be required to accept some level of constraint depending on the reverse power conditions of the connecting network and upstream network.

In theory the constraint level will be in the range between 0% and 100%, however based on early feedback from industry, NIE considers that constraint levels in excess of 20%/25% are unlikely to be workable for developers, given that developers had initially indicated a strong preference for constraint levels of less than 10%.

Ultimately the developer will decide on the level of constraint that will be acceptable for proceeding with connection. Information relating to the estimated level of constraint will be provided at the time of the offer (indications may be provided beforehand). This will be a non-binding estimate and actual constraint levels could change if there were any significant future decline in network load on a specific network. Equally, constraint levels could improve if additional load were to be connected to the network in the future.

This constraint information is likely to assume that connected generation operates at full output and may therefore be conservative. Applicants may require the addition of some further generation site specific and generator technology information to this NIE information in order to obtain a more accurate estimate of likely constraint.

It is important that the generator applicant fully appreciates the limitations of any constraint estimate, and in particular how the level of constraint may change in the future. The constraint, under normal operating conditions, is determined by the amount of ‘network capacity headroom’ available on the network (including the upstream network) to which the generation connection is made. The estimated constraint is not a fixed quantity but is variable and is affected by several factors:

- Circuit load profile
- Connected (& committed) generation
- Network Outages
  - Unplanned e.g. network faults
  - Planned e.g. network maintenance

The last item, network maintenance, is the only item that can be predicted and is largely within the control of NIE. As such it is the only factor that can be considered in the decision making process with any certainty. The prospective generation applicant would therefore need to make their own assessment of the overall risk.

Management of reverse power at any location will require active control of managed connection generation to safeguard the network against excursions outside critical operational limits. To achieve this it is crucial to develop a technically and financially
viable solution to manage these connections within the acceptable reverse power limits for any given location. Any solution will require all future connecting generators to comply with the requirements of such a solution.

In addition, network investment to increase the acceptable level of reverse power for a specific location may be considered, either alongside the reverse power management solution, or as an interim arrangement to enhance the level of reverse power headroom, although the issue remains as to how these investment costs should be allocated.

It is expected that a separate, but related, consultation in relation to changes to NIE's Statement of Charges may also be carried out, in order to consider the treatment of costs associated with reverse power control and/or the increase in reverse power capacity at any location.

6. Generator Management & Control Principles

The technical principles of generator reverse power flow management and control are outlined below.

Based on initial research, our current expectation is that operation would be enabled through NIE actively monitoring the reverse power flow at the 33/11kV substation supplying a particular network. This will require investment at each primary substation to obtain aggregated directional power flow information. In the event of an excursion beyond specific pre-determined limits (as explained in section 5) a signal will be communicated to one or more generators to reduce their generation output to zero in a controlled manner within a defined period in line with an agreed sharing arrangement discussed in more detail below.

When power flows return to an acceptable level a further signal will be communicated to the appropriate generator(s) to allow them to reconnect to the network. All generators will therefore be required to be capable of accepting signals from NIE and act accordingly in a timely manner as determined by the terms of their connection agreement to minimise impact on the NIE network and their own generators.

From our research there appears to be only two realistic methods of apportioning any constraint between generators i.e. the execution of reverse power management will either be based on [1] a ‘Last In First Off’ principle where the last generator committed is always the first to be taken off or [2] a ‘Shared Constraint’ principle where all generators accept equal constraint levels based on a rotation or cycling of reverse power management.

Regardless of the method of apportioning any constraint, it will be important to establish if any constraints would apply to generators currently connected on the basis
of a non-managed connection – i.e. should all existing connected and committed generation connections be excluded from any constraint under normal system operation?

Discussions with the industry to date suggests that in order to retain the bankability of generation projects and retain original inputs, all existing connected and committed generation should remain unconstrained; this is what has been assumed.

6.1. ‘Last In First Off ‘Constraint Principle

A ‘Last in First Off’ principle would be based on the generation queue, with those higher up the queue being constrained less often than those further down the queue. Any binding network constraint would be resolved by curtailing all generators in the order in which they applied for connection to the network. In this way generators are insulated against greater curtailment caused by the connection of later generation.

Therefore, should an excursion beyond the reverse power set point occur, the last to connect will always be the first to be constrained. Remaining generators connected on a ‘managed’ basis will then be constrained in turn according to their position in the queue until the level of reverse power has been controlled to a suitable level.

Similarly, when conditions allow, generators will be permitted to reconnect according to queue order, in effect on the basis of ‘Last In Last Reconnected’.

The position in the queue is set at the application stage when a full valid application has been received and registered by NIE. Applications which do not proceed or do not accept terms for connection will exit the queue as is the case at present.

6.2. ‘Shared’ Constraint Principle

A ‘Shared’ constraint principle will be based on an agreed rotation of all generators connected under the ‘managed connection’ arrangement, existing and future. So in effect, all generators connected on a managed basis will on average be constrained an equal number of times, although not necessarily of equal duration. The duration of each disconnection will ultimately depend on the network conditions prevailing at that time, with the resulting constraint being dependant on the generation prime mover conditions during any individual period of disconnection e.g. on a high wind day the impact for a wind turbine will be greater than on a low wind day for the same outage duration.

Furthermore, where a generator is constrained first in a particular event requiring reverse power management, that generator would be constrained last in the next event.
The position in the queue will therefore have no benefit beyond the day of connection. The terms of the shared constraint will apply equally to all connected generators, both present and future, and will be detailed in the connection agreement.

One of the key disadvantages of this principle is that generator output can be influenced by the connection of any future generation i.e. existing customers’ constraint expectation increases as each new customer connects.

This makes assessment of current and future constraint levels very difficult and adds significant additional risk when considered over the lifetime of the generator. These customers would therefore require some form of assurance that constraints will not exceed some level, limiting the number of generators connected to the network in this way.

In addition to the disadvantage described above, UK experience would suggest that in terms of practical implementation, a ‘shared’ constraint arrangement would be much more difficult to achieve. Commercial arrangements and the management of the very complex apportionment rules that would be required for any curtailment become very difficult, especially as future generation connects. As this arrangement will also apply to future connections, if this approach were adopted, it will be necessary to limit the number of generators connecting to avoid the level of constraint falling below an ‘acceptable’ level. Depending on the level that is deemed ‘acceptable’, this may impact the capacity that may be able to connect at a particular location.

6.3. Control & Communication

6.3.1. Communication Requirements

The principle of operation will centre on a controller at the source substation (33/11kV) communicating directly with each generator controller, to maintain measured network parameters to within specified operational limits.

To ensure continuous control of the risks of any potential excursions outside reverse power limits for a particular location, and to safeguard existing customers and the NIE network, it is vital that NIE maintains effective and reliable communication with all generators that are connected under the managed connection at any point in time.

Provision of communications from the generator to the source substation will be the responsibility of the generator. Where communication with a generator is lost for any reason (beyond any agreed ‘acceptable duration’), that generator will require disconnecting from the NIE network until communication is restored. The chosen communication method will therefore require a level of reliability appropriate to ensuring any disconnection due to a break in communications is minimised to a level acceptable to generators connecting under the managed connection.
So while the detailed communication requirements will be developed during an initial scoping design and pilot, suitable and reliable communications will be essential to the efficient operation of the managed connection, and will be a prerequisite for all managed connections prior to energising.

Significant disruption to polled radio and GPRS communications used in DNO applications typically occurs during poor and stormy weather and can be very significant. However, it is important to note that DNO network protection is provided by hardwired protection devices which, although they can be controlled via polled radio or GPRS communication, do not rely upon the communications for their operation. Communications reliability is therefore critical if generation is connected to the network without hardwired protection, especially if the generation can impact the safety or reliability of the electricity network. In extreme cases, if communications were lost to a managed generator or a number of managed generators, and if these generators continued to generate, there is significant risk of serious supply issues at the primary substation.

Recently measured SCADA reliability data would suggest that a polled radio solution, similar to the SCADA communication solution, will not be a reliable enough communication solution to monitor and control generators in real time, as required by managed connection reverse power management. It is likely therefore that a more reliable method of communication, perhaps based on fibre communications, will be necessary to provide the required level of reliability to ensure minimal interruption to managed generators as a result of communication failure.

NIE continue to investigate the impact that communications reliability may have on managed connections, but some initial feedback from UK DNO’s suggests that they have moved away from GPRS or polled radio due to reliability issues.

The level of reliability will ultimately be balanced against the cost to provide suitable communications and any resulting impact on generator down-time. Furthermore, any reliance on third party communications or service agreements will need to consider the service level provision for restoration of communications following an outage, which again will be a balance of cost against potential generator down-time. **Arriving at an appropriate balance of costs and reliability may therefore be a determining factor in a generators business case.**

### 6.3.2. Control & Communication Principles

Figure 2 below illustrates the role of communications in monitoring and controlling the individual generator management functions in line with the reverse power principles outlined above.

The level of reverse power flow at each source substation (33/11kV) will be actively monitored by a ‘controller’ at that substation. If the individual predetermined reverse
power flow setting for the primary substation is exceeded, the ‘controller’ will directly signal managed generators to disconnect in a controlled manner from the NIE network, according to the terms of their connection agreement.

Reconnection will be inhibited until the appropriate network conditions have been restored such that reconnection of a generator will be possible without causing a further excursion beyond the specific reverse power limits. At the appropriate time a further signal will be communicated to the individual generators to allow them to reconnect to the NIE network in a controlled manner.
Figure 4 – Generator Monitoring and Control Schematic
6.4. Generator Circuit Breaker Control Principles

The detailed principles of control will be developed through an initial scoping design and pilot. It is envisaged however that control of the generator to reduce its output to zero in a controlled manner will require to be an automated feature of the individual generator controls, initiated following a signal from the ‘controller’ at the source substation.

In addition, should the generator for any reason fail to respond to the signal from the source substation, NIE will require having control to directly trip the incoming generator circuit breaker to disconnect the generator from the NIE network. This will act as a back stop safety feature only, with the normal method of disconnection being that the generator will act accordingly to shut down in a controlled manner.

The performance of the customer’s installation including the generators control scheme must comply with the appropriate planning standards and not cause power quality issues on the NIE Distribution System.

7. Transition & Implementation

7.1. Transition arrangements

On completion of the consultation process, and subject to an acceptable technical ‘managed connection’ solution being developed, NIE would intend to announce a change to the way small scale generators are connected to the network. NIE envisages that at a future date referred to as the ‘implementation date’, to ensure a uniform and consistent and non-discriminatory approach, that all applications received will be offered a connection based on the new ‘managed connection’ arrangement, even though in certain circumstances constraints may never apply.

Detailed requirements of the managed connection will be published subject to successful completion of the consultation process and a satisfactory outcome from the working pilot. A high level estimate of the number of additional generators that might be connected under such an arrangement and the charging requirements will form part of the published information, subject to an appropriate charging mechanism being approved by the Utility Regulator.

In general, until such times as a managed connection solution can be offered to all developers the current arrangements will continue where remaining headroom at primary substations that have not reached saturation will be allocated in accordance with their generation queue position.

Up to the ‘implementation date’ applicants can be categorised as follows:
• Applicants applying for a connection at a location where there is currently scope to connect as a non managed connection.

• Applicants applying for a connection at a location where there is currently no scope to connect as a non managed connection.

Where there is scope to connect as a ‘non-managed’ connection, there will be no change to the current process i.e. applicants will be presented with a ‘non-managed’ connection offer within 90 days of their application. They will have a further 90 days to accept this offer.

Where there is no scope to offer a ‘non-managed’ connection, all applications (including those currently in the system) will be advised that a connection offer cannot be issued at this time and will be given the option to either exit the queue and receive a refund of the connection application fee, or choose to remain in the generation queue until a potential “managed” connection offer is available. Those choosing to remain in the generation queue will be put on hold and their position in the generation queue maintained.

On the successful development, funding and implementation of a managed connection solution, these applicants who have chosen to remain in the generation queue will be contacted by NIE to confirm whether they still wish to receive a quotation for connection under the ‘managed connection’ approach. Those customers wishing to proceed will be presented with a managed connection offer within an agreed timeline.

As there is significant potential for a large number of connection offers requiring processing, the timeline for receipt of a connection offer will need to be discussed and agreed with the Utility Regulator prior to the implementation of any new managed connection arrangements. Rules around how applications should potentially be prioritised for issue may also be required.

Following quotation, these customers will then have a further 90 days to accept this offer.

Refer to Appendix 1 - NIE statement on status of connection offers conditional on 33kV network reinforcement, 15th August 2014).

7.2. Implementation arrangements

From the ‘implementation date’ all connections will be offered on the basis of a ‘managed connection’.

All generators connecting under the ‘managed connection’ will need to be fully compliant with the technical requirements (including any D-code requirements) of reverse power management, even where the capacity at a particular location is such that the estimated level of constraint is zero.

While in this scenario a managed connection would be no worse off than for a non managed connection, the required functionality will provide for any future constraint...
that may need to be imposed due to any significant reduction in network load impacting the level of reverse power.

8. Network constraint principles

It is proposed that a ‘LIFO’ principle or ‘Shared Constraint’ principle will apply. The critical date that will apply to a ‘LIFO’ constraint arrangement in determining the level of applicable constraint will be the date of registration in NIE of a fully completed application.

The connection offer will include an estimate of the likely network constraint imposed in respect of reverse power flow management for the connecting generator. This assessment will be based on an analysis of the previous years load profile of the connecting substation along with any connected or committed generation. The estimated constraint will be described as a ‘percentage constraint’ and will be provided to the prospective generation applicant along with the 12 month load profile data for the connecting substation. It should be noted that load profile data will not specifically identify load and generation separately.

In addition the applicant will be provided with a high level view of connected generation and any committed generation ahead of the applicant in the generation queue, aggregated by generation type for the connecting circuit. Furthermore, if the LIFO principle applies the applicants position in the LIFO queue will be provided (at that point in time), albeit this may change if other applicants subsequently leave the process.

The estimated network constraint will be provided as a ‘snap-shot’ based on the network conditions at the time of application, with no guarantee given around future network constraint levels. There will be no undertaking to include this within the connection agreement and any constraint information provided will be non-binding.

Experience from the UK suggests that if DNO’s were required to provide “binding” maximum constraint levels to generators, significant underwriting of the financial risk to the DNO would be required, approved by the appropriate regulatory authorities, as constraint levels are not within the direct control of the DNO. The NIE analysis will not take account of any load factor associated with the connecting generator; therefore by default the NIE analysis will assume that the generator, and other managed generators, are operating at full output and will therefore present a more conservative estimate of the likely level of constraint. The applicant may wish to apply their own generator load factor assumptions in order to develop a more accurate curtailment estimate for their particular technology and supply arrangements.

NIE have assumed that there will be no constraint to customers who have secured their export capacity under a ‘non-managed’ connection arrangement.
9. Publishing Network Information

It is proposed to consider publishing the following online information:

- Network Heat Map – colour coded to provide a simple visual indication of areas already at or reaching saturation point.
- Network Mapping Tool - geographic view of three phase and single phase 11kV overhead line network.

All the provided information will be for guidance purposes only. NIE will have no responsibility for decisions made based on provided information.

The Network Heat Map can be accessed from the following link:


The Network Mapping Tool can be accessed from the following link:

https://www.spatialni.gov.uk/geoportal/NIEHeatMap/index.html

10. Charging Principles

There is currently some 270MW+ of SSG connected or committed to connect to the distribution network. In addition there are now some 400 applications where offers have been withdrawn or not made because of capacity constraints.

The primary driver behind the original conditional connection offers was the impact of reverse power flows from the 11kV distribution network through the 33kV/11kV primary transformers to the 33kV distribution network, leading to capacity limits being reached and the need to consider an alternative connection method to enable further connections.

With much focus on developing an appropriate technical reverse power control solution, it is crucial to consider the investment required to achieve such a solution, together with any network reinforcement that might be considered to increase the reverse power capacity at appropriate locations.

Network investment has now been completed at c.40 primary substations to increase the acceptable level of reverse power at those locations, releasing c.100+ connections offers. Furthermore, NIE has recently agreed mechanisms which might apply to enable further investment at additional primary substations, also subject to capacity limitations. NIE is currently working through the implications of this arrangement, but expect to be able to proceed with investment at a similar number of locations to the initial investment programme referred to above; it is anticipated that this may release a further c.120 connection offers. Future investment to enhance reverse power capability at other locations may also become necessary at a point in time.
Where capacity constraints remain, active management of the generators (Managed Connections) in some form i.e. through basic disconnection (or if appropriate trimming back output) of the generators attaching to the primary substations might be applied to ensure that reverse power flows do not exceed certain minimum levels. While the reverse power control solution will be developed through an initial pilot, it is likely that to enable a managed connection, investment will be required to provide capability to monitor power flows including reverse power flows in real time at a number of these 33kV/11kV primary substations. The costs associated with the IT / communications development required at the primary substations and distribution control centre are not clear at this point but are likely to be material to the overall business case for such an arrangement.

It is possible that the reverse power arrangements being considered may enable a number of additional generators to connect however this will depend on the extent to which any potential curtailment impacts their business case. Ultimately this may lead to cost being levied on each connecting generator however the timing of funding and sharing of costs presents a major challenge and some risk around recovery.

The development of a ‘managed connection’ will be subject to the findings of a suitable working pilot. While it is too early to accurately evaluate costs at this stage, pending the outcome of the pilot, the table below provides an indication of the scale of costs\(^8\) to implement managed connections, as a total cost based on 50 generators connecting at 10 primary substations:

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hardware &amp; Integration (Substation &amp; generator)</td>
<td>c.£700k</td>
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<tr>
<td>Annual Licence &amp; Support</td>
<td>c.£300k</td>
</tr>
</tbody>
</table>

**Figure 5 - Managed Connections Indicative Costs**

The CC indicated that the costs arising from investment to support renewables connecting to the distribution network should not fall on the general body of customers. Whilst this CC position is accepted, if we are to proceed with developing the managed connection proposal some mechanism is required to enable the necessary up-front investment to be made, albeit that this investment might be subsequently recovered from the generators as they connect to the network.

\(^8\) Costs are ‘total costs’ provided for indication only. Final costs will ultimately depend on the outcome of a competitive tendering process and will further depend on the number of generators connecting, and the relative numbers connecting at a specific substation location.
Accepting that while this position may ultimately limit the available investment options, the basic options appear to be as follows:

1. Developers pay the full cost for the automation (reverse power control) required to implement ‘managed connections’ at their connecting substation. On this basis we invite developers to bring forward options as to how apportionment of cost between developers might be achieved given that NIE must be entirely certain of payment via a single interface with the developers. Developers may wish to consider options along the lines of the following:
   
a. developers apply through a ‘gating’ type approach where implementation at a specific location might require a minimum number of accepted offers to implement, with each developer paying a share of the cost; or,
   
b. developers collaborate to share the costs through an agreed single point of contact, and settle payment through one of the collaborating parties

2. Developers pay the full cost for automation (reverse power control) in advance at a location and seek to recover the cost from subsequent connecting parties through some form of rebating approach.

Note however that this option relies on establishing and implementing a rebate mechanism which would ultimately require legislative change involving DETI and a public consultation. This could potentially take many months to process and implement, adding significant delay to any implementation of the managed connection.

3. The cost of automation (reverse power control) is treated as an ‘optimisation cost’ (this assumes that separately further investment at the primary substations are not justified from an asset replacement viewpoint) and this optimisation cost is initially funded by the NI customer with each connecting party paying a contribution to wind out the net RAB.

Note however that this would require a public consultation and a subsequent modification to NIE’s Licence. This could potentially take many months to process and implement, adding significant delay to any implementation of the managed connection.

4. The cost of automation (reverse power control) is borne by the NI customer as the most efficient way to develop the network to enable NIE to meet its obligations.

Note however, as outlined above, this appears to run in the face of the CC determination and therefore may not ultimately be a viable option. Furthermore, it should be noted that this would require a public consultation and subsequent modification to NIE’s Licence. This could potentially take many
months to process and implement, adding significant delay to any implementation of the managed connection.

It is expected that a separate, but related, consultation in relation to changes to NIE’s Statement of Charges may also be required, in order to consider the treatment of costs associated with reverse power control, and/or any future investment (beyond that which is currently being considered) to increase the reverse power capacity at further locations.
11. Consultation Questions

Viability of the Managed Connection

1. Given the increasing incidence of connections not being achievable at an escalating number of the locations, the current connection methodology has become untenable and a change in connection methodology might better utilise any remaining headroom between generator output and network load.

Assuming that an appropriate alternative managed connection approach can be developed which optimises remaining headroom at primary substations, do you believe such an alternative connection method should be considered to maximise the amount of generation that is able to connect, albeit that individual generator output it is likely to be constrained at certain times?

2. Our current estimate suggests that the earliest implementation of the managed connection would be around quarter 2 2016. How do you believe this timeline might impact on the viability of the managed connection approach?

3. The estimated network constraint will be provided as a ‘snap-shot’ based on the network conditions at the time of application. Due to varying load and generation conditions over time NIE will not be able to guarantee future network constraint levels. Therefore there can be no undertaking to include the estimated constraint within the connection agreement.

Do you accept therefore, that in adopting a managed connection approach, generators manage the risk of constraint due to changes in these conditions?

4. The consultation paper considers two theoretical levels of constraint that apply during a) 10% and b) 20% of the total hours in any single year. These notional levels were chosen following initial industry engagement which suggested that a constraint beyond these levels was unlikely to be acceptable in the majority of cases. For significant numbers of developers a constraint of only 10% may in fact be at the high end of what is considered acceptable, although it should be noted that a constraint of 10% of the total hours in any single year does not necessarily correlate to a 10% reduction in capacity factor as this will be depend on the type of generation technology employed and any additional locational factors.

Do you consider these theoretical levels of generator constraint, notably ‘10%’ and ‘20%’, as being the appropriate levels to consider? Please explain your reasons.

5. The managed connection attempts to best utilise any remaining headroom between generator output and network load, albeit with consequent possibility to constrain generators under specific network conditions.
Do you believe there is scope for developers to consider utilising energy storage/conversion in a way that increases the overall capacity factor of a power plant?

Provision of Information

6. Do you believe that the relevant technical matters have been adequately explained?

7. Do you believe the information to be provided by NIE in respect of network load profiling, connected generator profiling and estimated network constraint, to be reasonable and consistent with those areas where NIE is well placed to provide relevant information, as part of the overall information to allow a business case to be drawn up by the connecting generator?

8. Do you accept that the network constraint analysis undertaken by NIE will make no assumption around the load factor of generators connecting to the relevant circuits and that it is up to the applicant to incorporate NIE’s constraint analysis along with specific information in relation to generator load factor in order to complete a more complete picture of the possible level of constraint?

9. Have we provided sufficient information for you to understand the technical requirements of your generator to operate as a managed connection? I.e. that it is capable of:
   - being monitored by NIE at all times
   - receiving a signal from NIE in a specified protocol and converting that signal to a protocol specific to the particular generator;
   - acting on that signal to reduce output to zero in a controlled and timely manner (as agreed by the connection agreement);
   - inhibiting further generation until such times as a further signal is received from NIE to allow the generator to reconnect;
   - providing a fail safe facility to allow NIE to disconnect the generator from the NIE network should the generator fail to act on the ‘disconnect’ signal within the agreed timeframe.
   - Being required to disconnect in the event of a communications failure

Queuing Principles and Transition to MC

10. All existing and committed non-managed generation will retain their non-managed status. All managed connections will be processed according to their position in the generation queue and any constraint will be estimated based on this position.

In respect of any generator constraint, managed connection generators will be controlled based on either a) a ‘last in first off’ principle of generator control, OR b) a ‘shared’ principle of generator control. Initial feedback from industry groups favours the ‘last in first off’ principle of generator control over the ‘shared’ principle of generator control.
I. Have we adequately explained the ‘last in first off’ principle of generator control vs. the ‘shared’ principle of generator control?

II. The ‘shared’ principle adds significant complexity, time and cost to implement the managed connection. Taking account of this and the general view from early industry engagement, do you concur therefore with the initial view that favours the ‘last in first off’ principle of generator control? Please give reasons.

III. If the ‘shared’ principle were to be adopted, bearing in mind that existing customers’ constraint expectation increases as each new customer connects, what do you consider to be the maximum acceptable percentage constraint?

11. To ensure a consistent approach the managed connection will apply to all new applicants from a specified date, and to all existing applicants that have chosen to remain in the generation queue awaiting the managed connection. For new applicants, while this may result in some managed connections initially having little or no constraint, all connecting generators will need to comply with the requirements of the managed connection.

I. Have we adequately outlined these requirements?

II. Please outline any further comments of observations relating to this approach, together with any supporting examples.

12. Careful consideration will need to be given to prioritising the rollout of automated control at the appropriate substations which will ultimately release offers at those locations first.

While baring in mind that rollout costs may ultimately be impacted by how substations are prioritised, which of the following options do you feel provides the fairest means of prioritising this rollout? (Please provide rationale and outline any further options that you consider appropriate for consideration).

a. Prioritise substation with highest summation of queue positions applying to connect at that substation.

b. Prioritise substation with highest developer queue position; but offering connection to all developers wishing to connect to that substation.

c. Prioritise substation with highest summation of connection capacity.
Operational Factors

13. Do you believe that the generator operational management & control principles have been adequately explained?

14. Provision of communications from the generator to the source substation will be the responsibility of the generator. Reliable communications is central to the operation of the managed connection. If communication to a generator is lost (beyond any agreed ‘acceptable duration’) the generator will be required to disconnect until such times as communication is restored. It should be noted that any restriction to generator output due to a break in communication, is in addition to any constraint applied under the managed connection. The extent of this further restriction due to communications reliability may be a determining factor in a generators business case, and will therefore require further evaluation by the developer depending on the communications technology solution employed.

I. Do you understand that any break in communication (beyond any agreed ‘acceptable duration’) will further restrict a generators output?

II. In this context, but bearing in mind that the level of reliability will be somewhat in proportion to the cost, what level of communications reliability would you consider appropriate? Please give reasons.

III. Do you have a view on the type of communication medium that you consider to be most appropriate for this application?

Charging Principles

15. The development of a ‘managed connection’ will be subject to the findings of a suitable working pilot. While it is too early to accurately evaluate costs at this stage, pending the outcome of the pilot, the following table provides an approximate indication of the scale of costs to implement managed connection, as a total cost based on 50 generators connecting at 10 primary substations:

<table>
<thead>
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<th>Item</th>
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<td>c.£300k</td>
</tr>
</tbody>
</table>

Based on 50 Generators connecting to 10 Substations

These costs are provided for indication only. Final costs will ultimately depend on the outcome of a competitive tendering process and will further depend on the total number of generators connecting, and the relative numbers connecting at a specific substation location.
The Competition Commission Final Determination outlines their position that it was not in the public interest for the general customer base to fund further work in the area of 33kV investment to support renewables⁹.

I. Accepting that while this position may ultimately limit the available investment options, do you believe:

a. Developers should pay the full cost for the automation (reverse power control) required to implement ‘managed connections’ at their connecting substation, or a portion thereof where:

i. developers are invited to apply through a ‘gating’ type approach, where implementation at a specific location might require a minimum number of accepted offers to implement, with each developer paying a share of the cost?; or,

ii. developers collaborate to share the costs through an agreed single point of contact, and settle payment through one of the collaborating parties?

We invite developers to bring forward options as to how apportionment of cost between developers might be achieved given that NIE must be entirely certain of payment via a single interface with the developers.

b. Developers should pay the full cost for automation (reverse power control) in advance at a location and seek to recover the cost from subsequent connecting parties through some form of rebating approach?

Note however that this option relies on establishing and implementing a rebate mechanism which would ultimately require legislative change involving DETI and a public consultation. This could potentially take many months to process and implement, adding significant delay to any implementation of the managed connection.

c. The cost of automation (reverse power control) is treated as an ‘optimisation cost’ (this assumes that separately further investment at the primary substations are not justified from an asset replacement viewpoint) and this optimisation cost is initially funded by the NI

customer with each connecting party paying a contribution to wind out the net RAB?

Note however that this would require a public consultation and a subsequent modification to NIE’s Licence. This could potentially take many months to process and implement, adding significant delay to any implementation of the managed connection.

d. The cost of automation (reverse power control) is borne by the NI customer as the most efficient way to develop the network to enable NIE to meet its obligations.

Note however, as outlined above, this appears to run in the face of the CC determination and therefore may not ultimately be a viable option. Furthermore, it should be noted that this would require a public consultation and subsequent modification to NIE’s Licence. This could potentially take many months to process and implement, adding significant delay to any implementation of the managed connection.

Please note that no guarantee can be provided by NIE at this point that any of the above arrangements may readily be put in place however NIE will assess as best possible the workability of proposals brought forward by respondents

II. Notwithstanding your answer to i. above, in respect of any perceived benefits to customers in general:

a. Do you believe that developers alone should bear the costs for automation (reverse power control) required to implement ‘managed connections’?; or

b. Do you believe that customers in general would benefit from the ‘smart’ solutions required to implement ‘managed connections’, and in line with your view on the extent of any perceived benefit to customers in general, how should the costs associated with the automated control arrangement to implement the managed connection be shared between the NI customer and the developer?

Please state in percentage terms what you consider to be an appropriate sharing of benefit, and hence cost sharing, Developers: NI Customers, where 100% : 0% assumes the developer pays the full cost and 0% : 100% assumes the NI customer pays the full cost.

Please provide any detail you can and appropriate rationale to support your view.

Please note, as outlined above this approach may not align with the CC determination and therefore may not ultimately be a viable option.
12. Appendices

Appendix 1

Northern Ireland Electricity (NIE) Statement on status of connection offers conditional on 33kV network reinforcement

This statement (15th August 2014) relates to applications from developers of small scale generation for connection to NIE’s grid, who have or would receive conditional connection offers. The conditional terms, which have been included in these offers since March 2013, relate to 33,000 volt (33kV) network reinforcement.

The unprecedented level of applications from small scale generation developers has resulted in the saturation of the distribution network in a number of locations across Northern Ireland, particularly in the North and West. The impact on connection offers has been twofold.

Firstly, costs for connection associated with work on the 11,000 volt (11kV) network have risen markedly since 2012 due to additional reinforcement required in congested areas. These costs are directly chargeable to developers leading to escalating costs within offers.

Secondly, capacity limits on the 33kV network have been reached in a number of locations. Under NIE’s current Statement of Charges for Connection to the Distribution System (the "Statement of Charges" as approved by the Utility Regulator) the costs of 33kV investment to resolve these issues would fall to the general body of customers. However, early discussions between NIE and the Utility Regulator in January 2013 considered the extent to which it was appropriate to levy the costs of 33kV reinforcement to support the connection of renewables on the Northern Ireland customer base.

Further to these discussions NIE identified two possible options going forward. The first of these was to decline to issue offers on the basis that there was a lack of capacity on the network to make connections safely. The second was to issue offers conditional on 33kV investment being agreed by the Utility Regulator. NIE proceeded with the latter option from March 2013, whilst continuing to explore the extent to which any 33kV investments might be agreed.

The Utility Regulator approved some 40 discrete lower cost 33kV investments totalling £2.3m in October 2013. This led to conditional status being removed from over 80 offers to date, enabling work on these connections to proceed, and it will facilitate further non-conditional offers being made.
However, approval for the remaining higher cost investments has not progressed. In its final determination of the RP5 price control, the CC decided that levying further costs of 33kV investment on the general customer base to support small scale renewables was not in the public interest. Furthermore, following a dispute in respect of a conditional connection offer, the Utility Regulator’s recent determination (Determination DET-522) has concluded that "it is not reasonable for NIE to require the Complainants to accept the Conditional Terms" identified in the dispute, and: "Accordingly the Connection Agreement cannot include the Conditional Terms".

Consequently, NIE must now withdraw connection offers with conditional terms relating to the 33kV network, which have already been issued to developers.

However, where NIE can demonstrate that there is a lack of 33kV network capacity, as provided for in Article 21(1) (c) of the Electricity (NI) Order 1992 and, in respect of safety considerations, as provided for in Condition 30(5) (a) of the NIE Electricity Distribution Licence, then NIE is under no obligation to make a connection offer.

Accordingly, where NIE withdraws (as noted above) a conditional connection offer, and the conditions noted in the above paragraph are met, NIE will also be unable to make any further connection offer at this time. In addition, NIE will be unable to make connection offers for applicants seeking export capacity in such locations.

The above arrangements will apply to small scale generation applications - including G59, G83 Stage 2, Aggregated Generator Unit (AGU) and Demand Side Unit (DSU) applications.

NIE will now undertake a review of the Statement of Charges. This review will consider various options to deal with the 33kV capacity issue. These options will include whether 33kV investment might be passed to developers and/or whether alternative connection arrangements might be offered.

The revision to the Statement of Charges to adopt these options may involve a significant change to the current shallow connection charge policy. The Utility Regulator, who must approve any changes to the Statement of Charges, may deem it appropriate to publicly consult, and so this review may take some time to complete.

With regard specifically to alternative connection arrangements; work has been on-going to develop an approach whereby the output of the generator is controlled to avoid 33kV network capacity limits being reached and to reduce connection costs associated with 11kV network reinforcement. Similar approaches have been adopted by other network operators in GB, albeit there are inherent differences between the NIE network and those in GB which may impact the viability of this scheme.
NIE expects to bring forward proposals for consultation shortly, however taking account of the comprehensive nature of the Statement of Charges review and the detailed technical work required before any alternative connection method could be finalised, it is likely to take to the later part of 2015 before changes could be implemented.

NIE recognises that the difficulties in arriving at arrangements to deal with 33kV investment matters have led to high levels of frustration amongst applicants. After extensive engagement between NIE, the Utility Regulator and the industry, having explored a number of options, the Utility Regulator agrees that the approach outlined above, which reflects the circumstances in which NIE is unable to make connection offers, represents the viable way forward at this stage. NIE will continue to work closely with the Utility Regulator and the industry to implement this approach.