The Electricity Journal 30 (2017) 47–54

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/tej

Unintended consequences of Northern Ireland's renewable obligation policy

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A R T I C L E I N F O

Keywords:
Electricity network
Power grid
Wind
Renewable energy
Delivery
Learning

A B S T R A C T

Northern Ireland's Renewable Obligation Policy radically increased the amount of small and micro-scale renewable energy generation in the country, putting strain on the small and somewhat isolated grid. We review the impacts of the policy on the generation mix, and the resulting impacts on the power grid. We discuss a range of mitigation methods, and conclude with a recommendation that countries consider flexible policies to provide incentives for stability along with renewable energy.

1. Introduction

By 2020 Northern Ireland hopes to source 40% of its final electricity consumption from renewable resources (RaISe and L & RS, 2013). To help support these goals, in 2005 the country instituted the Northern Ireland Renewables Obligation (NIRO) policy, similar to the 2002 Renewable Obligation (RO) policy in Great Britain. Both of these schemes are a part of a UK-wide market for renewable obligation certificates (ROCs), which are the primary policy mechanism for increasing the level of renewable generation capacity in the UK. In Great Britain the RO policy led primarily to increases in the level of large-scale generation, as intended (Bassi et al., 2012; Hain, 2005). Northern Ireland hoped for a similar response to their policy: the Department of Enterprise, Trade and Investment (DETI), stated that the purpose of increasing the ROC support for solar "is to get 100 MW–200 MW of large-scale solar PV into Northern Ireland. That will contribute to our targets, enhance our security of supply and ease costs to the consumer" (DETI, 2014b).

The result of the ROC, however, was different: small- and micro-generation (SMG), with capacities between 11.05 kW and 5 MW, and below 11.05 kW respectively, increased by 365% between 2012 and 2014. This put significant pressure on the reliability and cost-effectiveness of the small and poorly interconnected Northern Ireland grid. While other countries have provided incentives for, and seen increases in, SMG, Northern Ireland is of particular interest since it has a relatively small grid with a high renewable energy target. While the entire UK RO program closed to new generation on March 31, 2017, there are lessons to be learned by looking at this case study.

In this article, we complement previous work discussing the RO policy in Great Britain (Mitchell and Connor, 2004; Mitchell et al., 2006) by providing a retrospective look at a broadened RO policy in Northern Ireland. Other papers have addressed the impacts of SMG as part of other challenges, such as distributed generation (DG) more generally (Barker and De Mello, 2000; Ochoa et al., 2006; Silva et al., 2016), including concerns with specific integration methods, such as the "fit and forget" technique (Strbac, 2007). We examine the impacts of the rapid increase in the level of uncontrolled SMG in Northern Ireland, which was deployed using "fit and forget."

The remainder of the article is organized as follows. Section 2 describes the NIRO policy. Section 3 discusses the impact of the NIRO on deployment of SMG. Section 4 reviews the impacts on the power system resulting from the significant increase in SMG. Section 5 discusses potential mitigation methods, followed by conclusions and policy implications in Section 6.

2. The Northern Ireland renewable obligation policy

The power systems in Northern Ireland and the Republic of Ireland make up the island's wholesale electricity market, the Single Electricity Market (SEM). The SEM is regulated by the SEM-Committee, made up of representatives from the two electricity regulators on the island, playing a role similar to the Federal Energy Regulatory Commission in the U.S. (RaISe and L & RS, 2013). While the island is connected in one Energy Market, the two countries have retained separate grids connected by four tie-lines and interconnectors. As of 2015, there were 840,000 electricity customers in Northern Ireland, supplied by three conventional power plants using coal, oil, and natural gas, totalling 1645 MW, and 694 MW of non-SMG renewable technologies (including wind, solar, hydro, biomass, and anaerobic digestion, with wind providing the bulk of the capacity). In comparison, the peak demand for

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http://dx.doi.org/10.1016/j.tej.2017.07.002

Available online 03 October 2017

2015 was 1759 MW (EirGrid, 2016), while the proportion of energy supplied by renewables has doubled from 10% in 2010 to 20% in 2013. In comparison, England, which consumes more than 35 times as much electricity, sourced 4.8% and 12% of its electricity generation from renewables in 2010 and 2013 (DECC, 2014). This comparison illustrates the small size and large proportion of renewables on Northern Ireland's power system compared to England. With such a small grid, Northern Ireland is a test bed for what would happen if large scale renewable penetration was implemented in larger power systems.

The UK RO policy came into effect in England, Scotland and Wales in 2002. This policy took the place of the Non-Fossil Fuel Obligation (NFFO), which was designed to primarily support nuclear generation while providing incentives for renewable generation (Mitchell, 1995). The NFFO policy supported large-scale generators through contracts for generation from specific projects. The ROC policy had a goal of more renewable development, but originally the policy mainly supported large established technologies. When the policy was first introduced, each generator received 1 ROC for 1 MWh of renewable energy generated, treating all technologies equally. A key difference between the RO and the NFFO is that the RO places a legal requirement on licensed electricity suppliers in the UK to source a portion of the electricity they supply from renewable sources (Mitchell and Connor, 2004). This requires developers to negotiate prices for electricity generation with suppliers, leading to a more competitive market for renewable technologies. ROCs are issued by Ofgem, the United Kingdom's regulator for electricity markets, and certify that a certain amount of energy has been generated by a qualifying renewable energy generator (Hain et al., 2005). Once they are obtained the generators can then trade ROCs with energy suppliers, who can use them to meet the RO and avoid paying a penalty. The monetary value of ROCs is determined by the market and influenced by the total amount of renewable generation on the grid and the size of the penalty (Hain et al., 2005). The NIRO was introduced in 2005 (Ofgem, 2015).

In 2009 it was noted that the one-to-one ratio of the ROC policy had primarily encouraged investment in well-established technologies. Thus, Ofgem introduced a range of support levels, from 1 to 4 ROC per MWh, for the various technologies, as seen in Table 1.

3. Impact of NIRO on SMG development

After the differentiated support levels were introduced, Northern Ireland saw a 365% increase in SMG between 2012 and 2014. This increase came as a surprise. DETI's "high" growth projection identified 267 MW of SMG by the year 2020 (Mccullough, 2015). By the end of 2015, however, there was already 187 MW of SMG connected to the power system: this rate of growth would lead to the 2020 "high" growth projection being achieved by 2017.

Table 1
Number of ROCs per MWh for SMG Technologies.

Technology	Year				
	2002–2009	2010	2014/15	2015/16	2016/17
Onshore Wind < 250 kW	1	4	4	4	4
Onshore Wind 250kW–5 MW	1	1	1	1	1
Solar < 50 kW	1	4	4	3	2
Solar 50 kw–250 kW	1	2	2	2	2
Anaerobic Digestion < 500 kW	1	4	4	4	4
Anaerobic Digestion 500 kw–5 MW	1	3	3	3	3
Hydro < 20 kW	1	4	4	4	4
Hydro 20 kW–250 kW	1	3	3	3	3
Hydro 250 kW–1 MW	1	3	2	2	2
Hydro 1 MW–5 MW	1	3	1	1	1

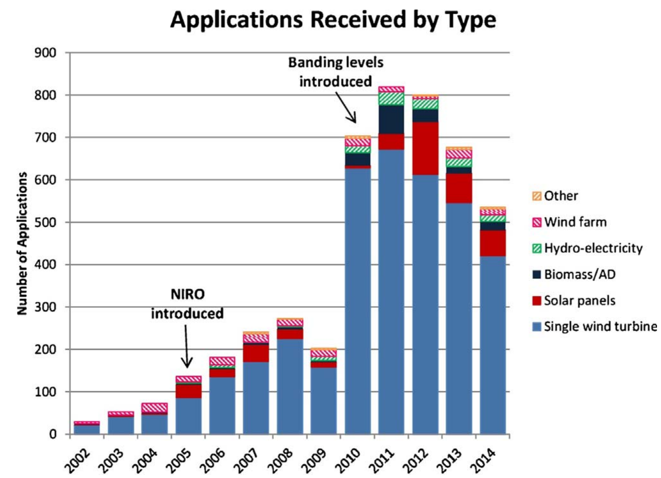

Fig. 1. Number of planning applications received by type of technology. Solid sections represent SMGs, while stripes represent non-SMG technologies. Data sourced from (NI Direct Website, 2015).

In order to get ROCs, most operators must have planning permission. Fig. 1 shows the number of applications for planning permission. It should be noted that some solar installations do not require planning permission, so the numbers shown underestimate the solar projects attempting to connect to the grid. The majority of solar panels and single wind turbines are SMG, while wind farms are large-scale generation.

The original NIRO policy, with a 1-to-1 ratio led to a small increase in applications. The introduction of the support levels described in Table 1 led to the significant jump in applications in 2010. Even with a high cost to connect to the grid, and a waiting period of nearly three years, the incentive to apply for a connection was large, because once approved, operators receive ROC payments for 20 years, in addition to the revenue generated from their energy production. The increase in applications was most significant for wind, followed by solar, then biomass.

The large jump in applications led to a rethinking of the policy. In 2012, the UK government announced it would reduce support for large-scale onshore wind under the RO to 0.9 ROCs between 2013 and 2017 (DECC, 2015). In June 2014 DETI proposed reducing the amount of ROCs for solar PV to 1.6 ROCs/MWh, citing a decrease in solar costs and the large increase in solar PV installations (DETI, 2014a). This proposal, intended to take effect in April 2015, was met with severe opposition from Northern Ireland's solar PV industry and over 330 responses in the consultation period. Thus DETI rescinded its proposed reduction in the solar ROCS, and stated that there would be no changes to ROC levels prior to October 2015 (Symington, 2015). Finally, in 2015, the Northern Ireland Enterprise Minister stated that the government would be ending the ROC policy a year earlier than originally planned.

Fig. 2 shows the increases in SMG cumulative installed capacity in the power grid over the 2012–2015 period, resulting from the increased applications. After planning applications are received there is typically a 2.6-year waiting period for generators to be connected to the power system (Mccullough, 2015). Between 2012 and 2015, microgeneration grew by 6400%, from 1 MW to 65 MW, and small scale generation grew by 388%, from 25 to 122 MW. Large-scale generation, on the other hand, increased by only 46% in the same time period.

In terms of specific renewable technologies, the number of accredited solar PV stations increased from 227, with an installed capacity of 1 MW in 2011, to 1138 stations with 5 MW in 2013, to 3750 stations with a combined installed capacity of over 20 MW in 2014. In 2010 there were approximately 395 onshore wind turbines with installed capacity of 40 MW, which jumped in 2014 to 523 turbines with a

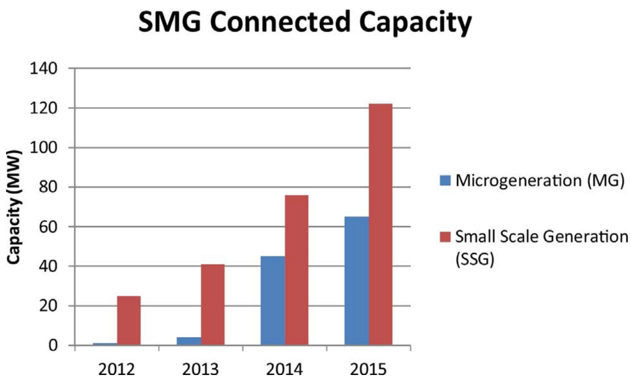

Fig. 2. SMG Cumulative Grid Capacity (NIE Connections, 2015).

combined capacity of 63 MW.

Fig. 3 shows how the locations of single turbines differ from that of wind farms. While large-scale wind farm applications have primarily been located in the west, where the wind resource is highest, single wind turbine applications have been dispersed throughout the country.

Prior to 2010, SMG played a minor role in power generation, and was thought to have little impact on the reliability and maintenance requirements for the power system. With the large increase in accepted planning applications and connected capacity dispersed throughout the country, particularly wind and solar generators, industry leaders have noticed the SMG having an impact on the electricity network, which we turn to in the next section.

4. Impacts of SMG on the Northern Ireland power system

We have identified four aspects of SMG in the Northern Ireland power system that have consequences for the system as a whole. Two aspects are specific to SMG: they are not controllable and they are essentially invisible to the grid operator. The third aspect is specific to wind and solar: they are intermittent and difficult-to-predict resources. The last aspect is related to the power system itself: the current fossil-fuel baseload generation has a minimum stable generation level. These

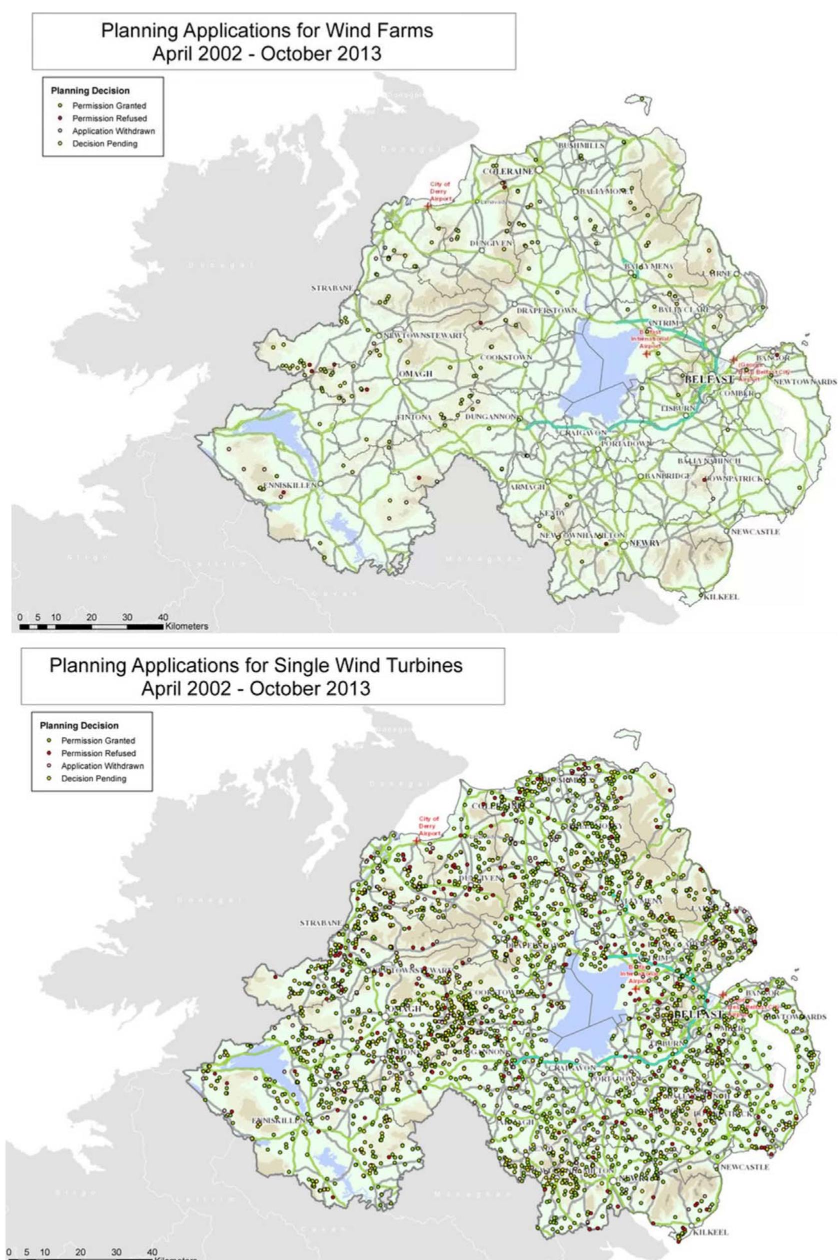

Fig. 3. Applications Received for Wind Farms (upper panel) and Single Wind Turbines (lower panel). Reprinted from NI Direct Website (2015) with permission.

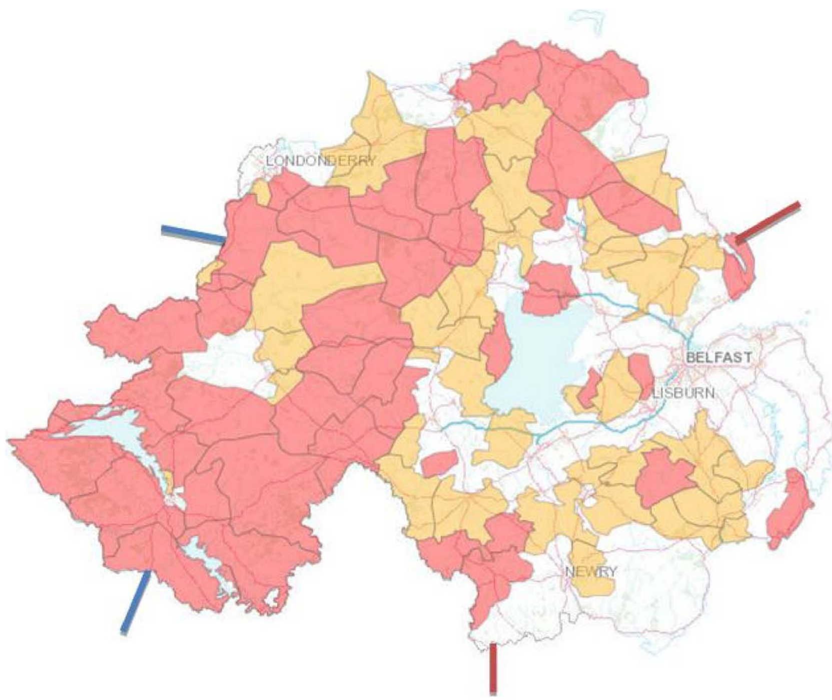

Fig. 4. Heat map of Northern Ireland's distribution network displaying the interconnectors and tie lines. Blue lines indicate tie-lines; Red lines indicate interconnectors. Red, orange, and white shading indicate a high, medium, and low cost to connect, respectively. Reprinted with permission (NIE, 2015). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

four aspects taken together lead to high system costs, instability, and increased risk of power outages and voltage fluctuations due to reverse power flow, and the crowding out of more controllable and cost-effective large-scale renewable projects. In the next two subsections we outline the causes and the consequences of the impacts on the power system.

The heat map in Fig. 4 indicates the level of cost for developers to connect to the Northern Ireland distribution system (NIE, 2015). High costs, represented by the red-shaded areas, are typically caused by congested lines and overloaded substations, thus giving a sense of where the distribution system is congested. The two tie lines and Scotland interconnector are located in the most congested parts of the distribution network, meaning this part of the network could be a bottleneck for transfer of electricity between the two countries. We note that the heat map shows the level of congestion at the distribution network, while the interconnectors are a part of the transmission network. Although the interconnectors are at a higher voltage level, congestion at the low voltage levels limits the route electricity can take to supply consumers; the overloaded substations could pose a problem for the transmission network, especially in the case of reverse power flow and frequency issues.

4.1. Causes

SMG is a type of distributed generation, which Pepermans et al. (2005) defines as "an electric generation source that is connected directly to the distribution network or on the customer side of the meter." In Northern Ireland, SMG capacity has been connected to the low voltage, 11 kV distribution network on the customer side of the meter. Power that is on the customer side of the meter cannot be directly seen, measured, or controlled by the system operator, unlike larger-scale generators connected to the 33 kV network. This unmeasurable power is simply seen as a disappearing load. For example, recently a 4.8 MW solar farm was connected to the Belfast International Airport. On a sunny day when the solar farm powers the entire airport, the airport's demand disappears from the demand seen by the power system operator (Lightsource, 2016).

These aspects of invisibility and uncontrollability are exacerbated by the intermittent nature of wind and solar. Even at large scale, these technologies provide challenges to the grid as their generation cannot be scheduled (they only generate when the wind blows or the sun shines) and are challenging to predict. Large-scale generation, however, connected at the 33 kV transmission level, can be curtailed at times of low demand; and wind and solar forecasting methods have been steadily improving. The System Operator for Northern Ireland (SONI) has a wind forecast target accuracy of 6–8% for the grid overall, and individual wind farm generation prediction accuracy has been seen to be 10–20% (Foley et al., 2012).

Finally, these aspects combined with the minimum stable generation of the current baseload plants lead to periods of potential over-generation in the system. To ensure system stability SONI requires the operation of three baseload power stations. When the three conventional plants are operating at their minimum stable generation, their output is 416 MW (Kubik et al., 2012). We define potential over-generation to mean that the sum of available solar, wind, and the minimum stable generation are greater than demand. For example, in 2014, July had a minimum net load of 480 MW, where the net load refers to the electricity demand minus the power from the unmeasurable SMG (SONI, 2014). This is barely over the 416 MW minimum stable generation from fossil plants; the large-scale renewable generation capacity was well over this minimum at 600 MW. Newbery (2017) has argued that subsidies based on generation, like the NIRO, rather than based on capacity, lead to locational pricing distortions that encourage high output from renewable energy generators regardless of demand levels, exacerbating this problem.

In Fig. 5, we illustrate the potential over-generation that results from the large-scale wind capacity currently connected to Northern Ireland's power system. The height of the bars indicates the total large-scale renewable capacity on Northern Ireland's power system. The blue section of each bar represents the amount of demand remaining after the minimum stable generation of the conventional generators is subtracted from the minimum demand for that month. The red section of the bars indicates the potential over-generation at periods of low demand. This potential for over-generation will get worse as more SMG are connected to the power system, causing further reductions in the minimum load.

Over time, the disappearing load caused by SMG may bring the minimum demand closer to, and possibly below, the minimum stable

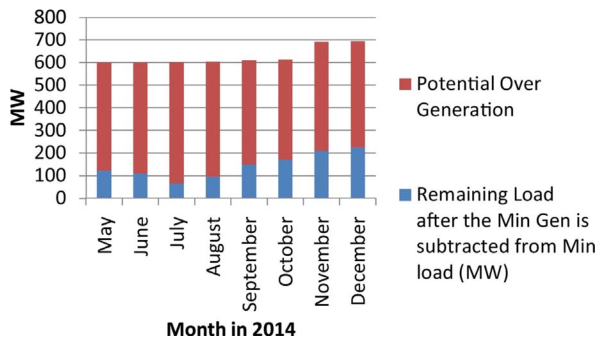

Fig. 5. Potential over-generation at times of low demand. (For interpretation of the references to color in the text, the reader is referred to the web version of this article.)

generation level of the three baseload plants in Northern Ireland. The minimum stable generation level of a conventional power plant is determined by the rate at which fuel can be combusted without leading to instability issues. Running a plant below the minimum stable generation level will significantly decrease the life of the generators, as well as increase the potential for loss of synchronism and voltage fluctuations in the power system. Therefore, a plant operator typically will not operate a plant if demand goes below the minimum stable level.

SONI's requirement for three conventional generators to be online at all times was intended to maintain system security, provide flexibility to respond to the shifts in output from renewable generation, and redundancy in case one of the conventional generators experiences an outage (Kubik et al., 2012). As SMG reduces the minimum demand, however, it makes it more difficult to comply with the three generator rule.

4.2. Consequences

The invisible, uncontrollable, intermittent aspect of SMG leads to inefficient operation of conventional generation. When SMG produce less power than predicted, the power system must quickly make up for this, typically using high-cost, inefficient, high-carbon "peaking" generators to produce power. In the absence of widespread SMG, the power system operator would be able to do a better job scheduling the lower-cost baseload generators. On the other hand, when SMG covers more demand than expected (i.e. times of low demand but high wind or insolation), fossil fuel generators need to power down, leading to increased cycling in plants that were not meant to vary their output. The cycling reduces the lifetime of the plant and can lead to higher emissions. In both cases the loss of efficiency stems from the unpredictable and uncontrollable nature of SMG. This is why the method of integration and placement of SMG technologies is key in the deployment of SMG technologies, as we will discuss in Section 5.

A second concern is instability due to reverse power flow. During periods of low load and high local energy production, electricity will attempt to travel in reverse, from the 11 kV network to the 33 kV network. This leads to the loss of synchronism between generators, mismatched windows of generation and load, and capacity issues. Consequences of this instability include increased risk of power outages, voltage fluctuations (which can reduce electrical equipment lifetime), power fluctuations, power factor changes, unintentional islanding, and grounding issues. Due to the majority of the wind resource being located in the west of Northern Ireland away from large demand centers, as seen in Figs. 3 and 4, the frequency of periods of low demand and high local energy production tends to be higher compared to larger, more interconnected grids.

Finally, the large number of uncontrolled SMG has been leading to a higher potential for over-generation, which in turn leads to increases in wind farm curtailment. Currently wind farms are compensated for curtailment under "constraint payments" (National Grid, 2016). These payments, which are for *not* generating, ultimately increase the consumer's cost of electricity. Northern Ireland and Ireland use constraint payments that are determined based on the pre-set market price of electricity. Ireland's Single Electricity Market saw €156 million in constraints payments in 2015; however, these cover a number of generators, not just wind. The Energy Institute in Ireland suggests that the main cause of the constraint payments is lack of interconnection between Northern Ireland and Ireland, as well as lack of interconnection between Ireland and the mainland UK (Energy Institute, 2016).

Even with constraint payments, the potential for increased wind farm curtailment may have discouraged investment into large-scale offshore wind farms, which can provide a more controllable energy source for the power system operators. Note that constraint payments are paid only when previously scheduled generation is canceled due to a last-minute change in demand. Given the reduction in the minimum demand caused by SMG, wind farms will be scheduled less often. This kind of curtailment – simply not being scheduled to generate even when wind is available – is not compensated, thus reducing incentives to invest in large, more controllable, wind farms.

In 2014 the First Flight Wind project, which would have placed 100 wind turbines off the coast of Northern Ireland, was abandoned. If it had gone forward as originally planned, it would have increased the renewable generation by 600 MW, meaning overall Northern Ireland would be sourcing over 30% of its energy generation from renewables. The project was first downsized to less than 400 MW, and then abandoned altogether (Mccullough, 2015). As shown in Fig. 5, the continuing reduction in net load, resulting in part from SMG, leaves only 50–225 MW of demand during periods of low load to be fulfilled by other sources. This implies that the offshore wind project may have anticipated reduced operation during periods of low demand impacting profits and project viability.

5. Mitigation methods

Large penetration of SMGs hold promise if proper control strategies are put in place (Daly and Morrison, 2001; Lopes et al., 2007; Heydt, 2010). System operators will need to address the increased risk for instability of the power system, the inefficient use of fossil fuel plants, and increased potential over-generation. In the following subsections we identify mitigation methods that could be used to improve the situation in Northern Ireland, and that could allow for more connection of SMG technologies in the future.

5.1. Demand response and distributed trading

Demand response programs are designed to shift the demand profile in the market. These programs reduce the spikes and dips in demand, aiding system operators in more efficient operation of the power system. It is through shifting the load profile that operators can reduce the need for higher-cost generators, and offer low-cost system balancing services (Faruqui and George, 2005). Distributed trading – energy trading behind the meter – is a relatively new concept that if implemented correctly could provide demand response services and reduce the threat of reverse power flow.

One type of demand response is demand bidding programs, which allow large-scale customers to reduce energy demand for a fixed payment during periods of high demand (Liu et al., 2015; Aalami et al., 2010), by offering an interruptible load; for example, implementing a temporary halt to manufacturing production for a couple of hours, or allowing system operators to remotely control air conditioners in the buildings during non-working hours (Cleland et al., 2016). A variation of this program could increase the demand of customers at periods of low demand, thus allowing the system to stay above the minimum stable generation. For example, remote control of air conditioners could be used to pre-cool a facility during times of low demand.

Pricing mechanisms are another option to shift the demand profile.

These range from simple peak and off-peak pricing, to real-time pricing. In peak and off-peak pricing there are two different prices for electricity during each day, with peak prices higher than off-peak. In real-time pricing the rates vary continuously during the day in response to both supply and demand. In California's Statewide Pricing Pilot it was shown that when pricing mechanisms were introduced, medium and commercial customers reduced peak period energy use (Faruqui and George, 2005). In order for real-time pricing to be effective, it will likely require technological upgrades, allowing machines to respond automatically to a changes in price and installation of smart meters to allow dynamic pricing (Faruqui et al., 2010). For example a “smart” thermostat could set the air conditioner in a home to a higher temperature during times of high prices. In addition, incentives will most likely require a suite of options to encourage broad participation in demand response programs (Bradley et al., 2016)

A more revolutionary concept is energy trading behind the meter. An example of this would be a home or business with SMG wind or solar and a nearby end-user with an electric vehicle. They could exchange electricity within their local grid, charging the vehicle when the electricity was available (Wang et al., 2011). Meeting demand locally reduces the threat of reverse power flow, transmission line congestion, and the use of high-cost generators. It is of most benefit if local energy trading is encouraged during periods of peak demand (Bayram et al., 2014). Energy trading could be particularly beneficial to Northern Ireland, with its large amount of distributed energy. It could also pose some challenges, because energy trading behind the meter would essentially create microgrids in an already small power system. Thus there would need to be more power system upgrades to allow for bidirectional energy trading, and increased communication and pricing mechanisms for the local level (Pagani and Aiello, 2011).

Demand response programs and distributed trading have the ability to mitigate many of the issues caused by SMG on Northern Ireland's relatively small power system. They can reduce potential over-generation by shifting demand to periods of high wind and solar power output, reduce cycling of fossil-fuel plants through smoothing the demand profile, reduce some investments in infrastructure upgrades, as well as provide incentives for distributed storage through the use of electric vehicles. These solutions require innovation in both policy and technology to be fully realized.

5.2. Upgrades to the power system infrastructure

Another way to alleviate stresses on the power system is more purely technological: upgrading and reconfiguring the transmission and distribution network infrastructure. As seen in Figs. 3 and 4, the majority of congested areas with large amounts of SMG are in the west of Northern Ireland while the primary demand center, Belfast, is located in the east. In late 2013 the utility regulator granted a £2.3 million investment approval to Northern Ireland Electricity to upgrade 40 substations (DETI, 2014b). Substations and transmission lines need to be upgraded to deal with the threat of reverse power flow, and for relief of congestion to permit the transportation of energy across further distances.

In addition to standard infrastructure upgrades, another method involves changing the way operators connect SMG to the power grid. The clustering method, illustrated in Fig. 6, consists of connecting local generators to one substation, which is then connected to the power system, as opposed to the current method of directly connecting each generator to the power grid.

This central substation would provide system operators with the ability to control and determine the level of power being produced from a group of SMG. Since a new substation has to be constructed, the method has higher upfront costs for developers, but there are environmental and visual benefits from reducing the amount of power lines needed to span Northern Ireland.

If the system is updated to handle the high penetration of the SMG, the potential positive impacts on the power system can include reduced network flows, and subsequently reduced losses and voltage drops (Passey et al., 2011).

Finally, an important solution to many of the challenges is to add interconnectors to other demand centers. The minimum demand could be increased through the proposed – but not yet built – North-South interconnector between Northern Ireland and the Republic of Ireland. The 400 kV cable would be the largest grid connection between the two countries, and span counties Armagh and Tyrone in Northern Ireland, and counties Monaghan, Cavan, and Meth in Ireland. This project was originally planned to be completed in 2017, but as of 2016 the three-year project has not been started. If built, this interconnection would relieve some of the congestion on Northern Ireland's power lines, reduce the need for constraint payments, and provide greater stability to the system.

5.3. Energy storage

Another technological solution that ties in closely with demand response is the addition of energy storage. While energy storage is still expensive, it appears that costs are dropping fast for battery packs for electric vehicles (Nykvist and Nilsson, 2015); this may impact the stationary market as well. Utility-scale storage, including pumped hydro, compressed air, or banks of batteries, could replace aging conventional power plants, and provide peaking capabilities once supplied by oil and gas plants. Smaller scale distributed storage, located at the residential site near PV solar, could counteract the fluctuations in power output from SMG (Cole et al., 2016; Hoppmann et al., 2014), and reduce voltage swings stemming from reverse power flow (Ratnam et al., 2015). Adding energy storage would allow power system operators to balance energy flow between generators and demand centers, while providing the system operator with more control.

5.4. Ancillary service programs

Ancillary service programs could reduce revenue losses of larger more controllable wind farms (Nock et al., 2014). By allowing wind to receive payments for performing some of the frequency balancing services that conventional generation normally provides, the operator would be able to maintain the reliability of the power system, while becoming less dependent on fossil fuels (Shapiro et al., 2017). Reducing the need for the fossil fuel plants in Northern Ireland could have environmental benefits, while at the same time assist Northern Ireland in reaching its renewable energy targets.

Again, this solution requires innovation in policy and in technology. Currently, wind farms are able to power down easily; they can power up by generating at less than full power. Some new work shows the potential for powering up at much lower cost by taking advantage of the inertia in large wind farms (Shapiro et al., 2017).

6. Conclusions and policy implications

In Northern Ireland, the NIRO policy has succeeded where its predecessor, the NFFO, failed: increasing the diversity of generation technologies connected to the UK power system. This policy, however, caught the Northern Ireland grid operators by surprise, encouraging a large uptake of uncontrolled SMG technologies, particularly wind and solar. We note, however, that a similar policy led to a different response in mainland UK. It may be valuable to investigate this discrepancy in order to better predict the response to future policies aimed at increasing renewables.

Distributed renewable energy provides challenges to the power system. It has led to increased costs, potential over-generation, and a need for investment and upgrades to the electricity infrastructure in Northern Ireland to ensure stability of the overall system. There are a number of potential solutions, ranging from infrastructure and

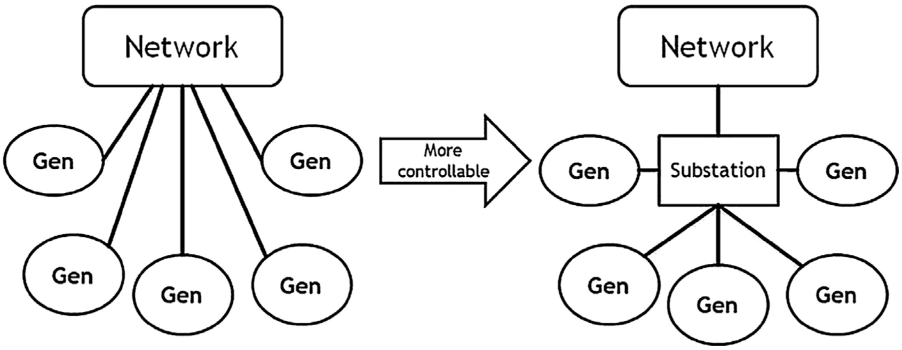

Fig. 6. Traditional (left) method versus the cluster technique (right).

technology upgrades to policy innovations allowing for demand response, distributed trading, and provision of ancillary services by intermittent technologies. Perhaps the overarching question is how to provide incentives for the full range of technologies and policies that can support the low-carbon grid of tomorrow. Certainly, technological innovations and investments will be part of the solution, with more interconnections and updated infrastructure allowing for smoother integration. At the same time, it is important to consider the policy frameworks that will best support the grid of the future. One direction is for nations to focus on flexible low-carbon emissions targets and policies, rather than more technology-specific policies such as renewable energy goals. More general policies would provide broader incentives for electricity storage, demand response, flexible generation, or even land-use reforms.

Northern Ireland, with its small, poorly interconnected grid, is a canary in the coal mine for the challenges of integrating large amounts of small, distributed generation. The experiences here can be seen as a test case for countries with larger power systems that wish to increase the share of renewable technologies supplying electricity.

Acknowledgements

This work was supported by the George Mitchell Scholarship Program; the NSF-sponsored IGERT: Offshore Wind Energy Engineering, Environmental Science, and Policy [grant number 1068864]; and the National Science Foundation Graduate Research Fellowship [grant number 1451512].

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