REVIEW OF RO BANDING FOR SMALL-SCALE RENEWABLES

A REPORT FOR THE DEPARTMENT OF ENTERPRISE TRADE AND INVESTMENT

JANUARY 2014

FINAL REPORT

prepared by:

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Project part financed by the European Regional Development Fund under the European Sustainable Competitiveness Programme for Northern Ireland.

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EXECUTIVE SUMMARY

CEPA, together with PB Power, has been engaged by DETI to carry out a review of current subsidy levels under the Northern Ireland Renewables Obligation (NIRO). Our terms of reference were specifically focused on the sub-5MW level, and on the following four technologies: solar PV[1], wind, anaerobic digestion (AD) and hydro. The project had the following high-level objectives:

- to identify changes in technology costs (current and likely future costs);
- to assess the implications of changes in costs for required subsidy levels;
- to consider whether other changes were required to subsidy levels or banding;
- to identify the costs and benefits of any changes; and
- to make a recommendation on future banding levels.

We were also asked to compare costs in NI with four other countries: Great Britain, the Republic of Ireland and two international countries chosen by CEPA; in this case, the Netherlands and Denmark. The project was delivered through a combination of desk-based research, economic modelling and discussions with key stakeholders. We are very grateful to everyone who took the time to speak to us.

Changes in assumptions, including costs, and the implications for banding

We start by looking at the changes in costs and the potential implications for NIRO support levels. Table 1 below shows how capital costs – the key component - have changed from our estimates used in previous modelling for DETI in 2010.[2]

Table 1: Comparison of 2010 and 2013 technology capital costs

Technology	Size Band	Current estimate	2010 estimate	% increase/ (decrease)
Onshore wind	<5	6,500	5,311	22%
	5-50	6,500	3,187	104%
	50-500	3,100	2,656	17%
	500-5000	2,200	1,593	38%
AD	50-500	4,750	4,993	-5%
Hydro	<5	10,000	5,311	88%
	5-50	8,400	4,249	98%

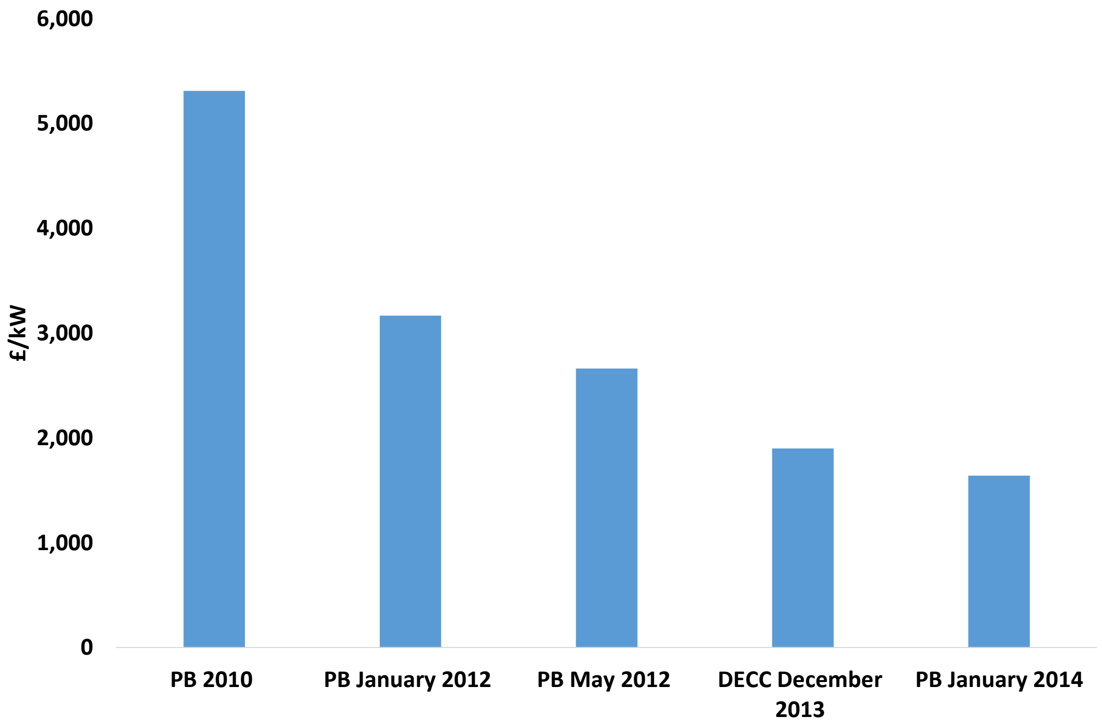
[1] For solar, we only considered installations up to the 250kW level, since larger installations have been covered by a recent DETI consultation.

[2] CEPA and PB modelling for DETI. Final model outputs published on the DETI website (not including technology cost assumptions): http://www.detini.gov.uk/cepa_pb_incentivising_renewable_electricity_generation_in_ni_final_report__volume_a__13_08_10.pdf

Technology	Size Band	Current estimate	2010 estimate	% increase/ (decrease)
	50-500	6,800	3,187	113%
	500-5000	3,500	2,656	32%
PV	<5	1,640	5,311	-69%
	5-50	1,243	4,568	-73%
	50-500	1,060	4,249	-75%
	500-5000	1,000	3,718	-73%

In short, there has been a very significant drop in costs for PV and increases for some other technologies. The trend over time for PV is shown in Figure 1 below. As will be seen, there has been a drop of around two-thirds since 2010.

Figure 1: Installation costs for PV (sub-4kW) over time, in £/kW



We have also considered whether there need to be changes to other key assumptions, including the appropriate cost of capital, power prices, carbon prices and deployment profiles.

For cost of capital, we consider that our previous assumptions modelling for DETI[3] – of around 3% for households and 7.5% for commercial installers – remain valid. While cost of capital does affect the required ROC level, the fact that our assumption has not changed

[3] CEPA and PB modelling for DETI. Final report published on the DETI website (not including technology cost assumptions): http://www.detini.gov.uk/cepa_small_scale_fit_study_-_final_report.pdf

means that there is no reason to consider potential changes to the ROC level based on cost of capital.

Our other assumptions have been updated, but in line with DECC's approach to RO banding we have not changed the ROC levels purely based on updates to these assumptions.

We then assessed what these changes would mean if there were a consequent change to the ROC level. This is shown in Table 2 below. Note that these figures do not represent our recommendations, only options to consider.

Table 2: Potential new ROC levels, based on cost changes

		ROCs		
Technology	**Size Band**	**Current**[4]	**New**	**Comments**
Onshore wind	Up to 250kW	4	4.5	Driven by increase in capex
	250kW to 5MW	1	1	Limited evidence at this scale in NI
Solar PV	Up to 50kW	4	1.6	Uses different methodology to deal with very large drop in costs
	50kW to 250kW	2	1.6	Modified to fit with the lower band
Anaerobic Digestion	Up to 500kW	4	4	
	500kW-5MW	3	3	
Hydro	Up to 20kW	4	6	Significant increase in capex
	20kW to 250kW	3	4.7	Significant increase in capex
	250kW to 5MW	2	2.6	Significant increase in capex

The direction and scale of the changes is in line with that for the technology costs. There is no change for AD and a possible increase for wind and hydro. For PV, the change in capital costs would lead to a significant drop in subsidy levels. Indeed, our analysis of the change in costs suggests that more substantial drops could be justified. For consistency, we have limited the change so that the figure for PV is the same as for larger-scale PV.[5]

Other potential changes to banding

We also considered a number of other possible changes to banding. Some of these were to deal with grid connection cost increases, while others were based on comparison with the GB FIT bands.

Taking the grid connection cost issue first, we looked at what the impact on ROC levels would be if those levels were increased to compensate for the much higher connection costs in some areas. However, the size of the increase needed (around 1.5 ROCs) makes this

[4] Source: DETI, August 2012, *Government Response to the consultation on proposed changes to the Northern Ireland Renewables Obligation in 2013*

[5] DETI has set ROC levels for ground-mounted solar PV above 250kW to 1.6, 1.5 and 1.4 ROC for 2014/15, 2015/16 and 2016/17 respectively. (DETI, January 2014, *Government Response to the consultation on proposed changes to the Northern Ireland Renewables Obligation on ground-mounted solar PV above 250kW.)*

an expensive option. It also does not resolve wider issues around connections, such as that some are conditional on future network upgrades. We therefore rejected it.

Turning now to the comparison with GB FIT levels, we considered whether there were obvious differences which might suggest options to consider for NI. We identified the following:

- providing 4 ROCs to 250-500kW wind; and
- providing 3 ROCs to 250-500kW hydro.

The latter option was rejected based on a combination of cost-effectiveness and the apparent lack of potential at that level. This leaves only the option of extending 4 ROCs to 250-500kW wind for further analysis.

Finally, we considered the option of providing a separate band for multi-site installations. However, the relatively limited potential for saving here did not, in our view, outweigh the complexity and administrative cost that adding the new band would entail.

Assessment of costs and benefits of changes

We took the options identified and assessed their quantifiable costs and benefits. The results are shown in Table 3 below.

Table 3: Quantified costs and benefits for options considered

Options	Net benefit/ (cost)	Impact on consumer bills (per household in 2020)
PV – 1.6 ROCs	0	-2.7p
Wind – 4.5 ROCs	0	1.9p
Hydro – additional ROCs	-£1.74m	0.5p
Extend sub-250kW wind band to 500kW	-£95.7m	13.0p
CENTRAL – all	-£101.3m	14.6p

Based on this, we recommend only the reduction in PV ROC levels.

It should be noted that the net benefit of this change is very small, when considered at a household level. This is because the change is to a relatively small part of the RO, and so annual savings are of the order of £1m. When these are shared across the UK's 27 million households, and account is taken of NI's lower Renewables Obligation level, the annual saving per household is small. Similarly, there will be no noticeable impact on the Levy Control Framework.

We also undertook sensitivity analysis around our results. This suggested that our conclusion that reducing PV subsidy to 1.6 ROCs would reduce household bills was robust to a range of alternative assumptions.

Benchmarking with other countries

To give our results real world context, we conducted a cost benchmarking exercise between NI and GB, the Republic of Ireland, the Netherlands and Denmark. This showed that, broadly speaking, NI has similar capex costs to the comparator countries, with the central values for the other countries within the high-low range of the NI data. There are indications that solar PV in the ROI is more expensive than in NI or the other comparison countries, but the PV market in ROI is much less developed than in NI or elsewhere, with significantly smaller total installed capacity, and this is likely to be a key factor in the higher costs.

The more limited opex comparison indicates that opex costs are also broadly similar between NI and the comparator countries.

Conclusions and recommendations

Our key recommendation is that the ROC level for PV should be reduced – we recommend to 1.6 ROCs per MWh. This is driven by the fall of around two-thirds in the cost of PV installations since 2010.

We have considered other changes, such as introducing new bands, or providing a different tariff for multi-site installations. We do not consider that any of these other changes are warranted, either because they have a net cost, or because the complexity and effort of introducing them is not justified by the potential benefits for the last two years of the NIRO. We recommend that DETI revisits these issues when considering the design of the FIT, as the balance of costs and benefits is likely to be different for a scheme with a longer lifetime.

1. INTRODUCTION

CEPA, in consortium with Parsons Brinkerhoff (PB), was commissioned by the Department for Enterprise Trade and Investment (DETI) to undertake this study of the subsidy levels for small-scale renewable electricity in Northern Ireland (NI). Specifically, our remit was to consider the current support levels for four technologies – onshore wind, solar PV, hydro and anaerobic digestion – and analyse whether any should in future receive a lower subsidy because of changes such as reductions in technology costs. This study is focused only on small-scale generation, which here is defined to mean less than 5MW. In NI, these are subsidised through the Northern Ireland Renewables Obligation (NIRO).

As well as considering what appropriate changes to subsidy levels might be, we will also look at the implications of our work for consumer bills, government costs and the achievement of NI's 2020 renewable energy target. We will also look at implications for the grid, planning and to the extent relevant the Single Electricity Market (SEM) as a whole.

1.1. Structure of this report

Following this introduction, this report is structured as follows. We start in Section 2 by setting out some of the context in which small-scale renewable electricity in NI operates. This includes a discussion of the NIRO and the SEM, as well as the subsidy schemes in the neighbouring countries of Great Britain (GB) and the Republic of Ireland (ROI). Section 3 sets out the approach we took in this study, while Section 4 then looks at the assumptions and data we have gathered, including updates to the technology costs and financing assumptions that lie behind estimates of the cost of renewables. These are compared with the figures from previous analysis to highlight any differences. Section 5 sets out a comparison of renewables in NI and four other European countries. Section 6 then presents the results of our analysis in terms of any changes in the level of subsidy required. This is followed in section 7 by a discussion of the impacts of these changes in subsidy levels. Finally, Section 8 concludes. The report also contains a number of annexes containing data tables and other detailed supporting information.

1.2. Acknowledgements

This report has benefited from comments and input from a number of stakeholders; a list is in Annex A. Stakeholders' views were collected on an anonymous basis and we have not attributed particular comments or views to any particular stakeholder. We are also grateful to DETI for their comments on drafts of this report. However, the report and its conclusions are ours alone.

2. CONTEXT

This section sets out the context for this study, starting at the original EU-level drivers for renewable electricity and moving to the need to update NIRO banding on a regular basis. We also present brief descriptions of the GB and ROI support for small-scale renewables.

2.1. Policy drivers

We start at the EU level, where there were a number of policies set out in late 2008 and 2009 in the EU's Climate and Energy Package. This included the Renewables Directive, which put in place specific targets for all EU countries to deliver a certain level of renewable energy by 2020.

At a UK level, the key plan is the Renewable Energy Roadmap, which includes a foreword signed by both the UK Secretary of State and his counterparts in the devolved administrations, including Arlene Foster for NI. The Roadmap sets out the actions that the UK is taking as a whole, and includes indicative ranges for different technologies.

This UK and EU context will form a backdrop for our analysis. We now consider the current situation, policy and plans in Northern Ireland.

2.1.1. The Northern Ireland context

DETI has set out an ambition in the Strategic Energy Framework for 40% of electricity to come from renewables by 2020. One possible breakdown of how this might be delivered, by technology, is given in Table 2.1 below.

Table 2.1: Indicative breakdown of possible installed capacity in 2020

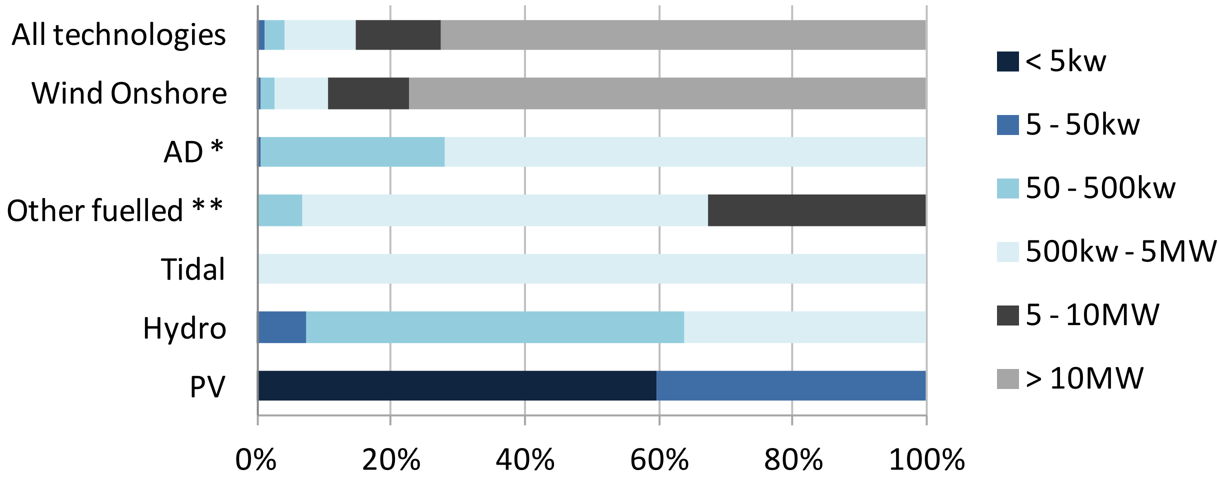
Technology	Installed Capacity 2020 (MW)
Onshore wind	2,000
Biomass	313
Other	111
Small-scale generation	7

Source: Ove Arup 2009

These figures show small-scale renewables making a relatively small contribution to the overall target. Based on the Ofgem ROC register, currently they provide a little over 10% of total renewables capacity[6] in NI. This is slightly less than the contribution of NI's single largest windfarm, the Slieve Kirk site[7]. Figure 2.1 below provides a more detailed picture.

[6] Ignoring the Kilroot power station.
[7] 73MW. Source: SSE. http://news.sse.com/listing/2013/11/%C2%A3125m-slieve-kirk-wind-park-officially-opened/#.Us1qyfRdWao

Figure 2.1: Contribution by size category to existing NI renewable generation capacity



Source: Ofgem ROC register

** Anaerobic Digestion ; ** Other fuelled includes landfill gas and biomass*

While overall, the vast majority of capacity is provided by renewables at the >5MW scale, there is significant variation by technology. In particular, AD is all at the sub-5MW scale, while for onshore wind the corresponding figure is well under 10%.

To obtain a fuller picture, we now also consider the *number* of installations, and the relative importance of each technology at the sub-5MW level. This is shown in Table 2.2 below.

Table 2.2: Sub-5 MW renewable electricity installed to date in NI under the NIRO

Technology	Capacity		Number		Average capacity
	kW	%	No.	%	kW
Wind	61,945	63%	517	15%	120
AD	4,614	5%	8	0%	577
Hydro	3,642	4%	34	1%	107
PV	15,295	16%	2,923	83%	5
Other	13,032	13%	22	1%	592
Total	98,528	100%	3,504	100%	1,401

Source: Ofgem ROC register (data sourced February 2014)

As this shows, wind accounts for around two thirds of installed capacity at the sub-5MW level. However, PV accounts for around three quarters of the installations. This is consistent with the messages from our discussions with those active in the market that wind installations tend to be around the 150kW level, and account for the majority of capacity, while PV installations are more numerous but – because they are often small domestic installations – contribute less to overall capacity.

2.2. UK and ROI small-scale renewable support mechanisms

As well as considering the overall renewable energy ambitions and likely levels of deployment across the British Isles, we need to consider the existing policies in place for supporting small-scale renewable electricity. We start with the NIRO, before considering the GB small scale FIT and the REFIT in the ROI.

2.2.1. NIRO

The NIRO (Renewables Obligation) is the support mechanism for renewable electricity in NI. Renewables generators receive a certain number of ROCs for each MWh generated, and these can be sold to NI or GB suppliers, who must hold a certain number at the end of each year.

A key difference between NI and GB is that the NIRO supports renewables at all scales, whereas in GB the situation is more complex. Below 50kW, installations must use the FIT. Between 50kW and 5MW they have the option[8] of the RO or the FIT, while above 5MW they must use the RO.

2.2.2. The GB FIT

The GB FIT scheme was introduced on 1 April 2010 to promote the uptake of small-scale renewable electricity generation. Individuals and businesses eligible for the scheme are paid a set amount per kilowatt hour (kWh) they generate and use themselves, which will vary according to the type of generation and the size of the scheme. In addition they are paid 3p/kWh for any surplus exported to the grid. The level of payment is fixed for between 10 and 25 years depending on the type of technology and is linked to inflation. Depending on scale and technology, the rates for different installations decrease each year for new entrants into the scheme. Current tariffs for wind are shown in Table 2.3 below.

Table 2.3: Current tariffs for small-scale wind in GB

Size band (kW)	Tariff (p/kWh)
<1.5	21.65
1.5-15	21.65
15-100	21.65
100-500	18.04
500-1,500	9.79
1,500+	4.62

[8] Installations between 50kW and 5MW have the option to use the RO. Source: DECC. http://webarchive.nationalarchives.gov.uk/20121217150421/http://www.decc.gov.uk/en/content/cms/news/pn12_114/pn12_114.aspx. Most of the installations on the Ofgem ROC register for GB are below 5MW, suggesting that this is a popular option.

The FIT scheme requires participating licensed electricity suppliers (FIT Licensees) to pay tariffs to generators for electricity generated and exported. All licensed electricity suppliers are required to make payments into Ofgem's levelisation fund, based on their market share of the GB electricity supply market. The levelisation fund is then redistributed to FIT Licensees that have made more payments than they would be required to by their market share contribution.

2.2.3. ROI context

The electricity supply for NI is closely linked to that for the ROI. We therefore need to consider future energy plans and scenarios in the ROI.

Overall, levels of ambition by 2020 are slightly higher than those in the UK (e.g. 16% renewable energy, and a slightly greater percentage of renewable electricity). Regarding how these ambitions might be achieved, the Irish Department of Communications, Energy and Natural Resources sets out five strategic goals in its "Strategy for Renewable Energy: 2012-2020". The most important, for the current project, is to increase "the proportion of wind in the energy mix – with offshore generation aimed at export to UK and North West Europe".

In the ROI, all renewable generation – large-scale or small-scale – is supported through the REFIT. Box 2.1 below presents a short summary.

Box 2.1: The REFIT in the ROI[9]

The Renewable Energy Feed in Tariff (REFIT) was launched in 2005 to replace the Alternative Energy Requirement (AER) mechanism with the stated purpose of stimulating sufficient capacity to meet Ireland's 2010 renewable energy targets under EC/2001/77.

The REFIT system is designed specifically to encourage new capacity development and so applies to newly built projects. In order to ensure that projects qualifying for support were in a position to build within a reasonable timeframe, the minimum conditions necessary to apply for support were also updated to include a requirement to have a valid grid connection offer in place.

Since the REFIT support mechanism became operational, 1,380 MW of renewable energy has qualified for the scheme.

Once any supplier agrees to purchase all of the output from a renewable generator under contract for 15 years, it is entitled to a REFIT payment including:

- a balancing payment intended to cover costs associated with non-dispatchable generators;
- a technology difference payment to promote diversity in renewable generation; and
- an opportunity cost payment in relation to the cost to the supplier relative to what that supplier would have paid for that energy in the market.

The levy is collected by suppliers from all final customers and paid to the distribution system operator or transmission system operator as appropriate.

At present, the proposed feed in tariff levels are as follows:

- large-scale wind energy (over 5MW) @ 6.9235 cent per kilowatt hour;
- small-scale wind energy (under 5MW) @ 7.1664 cent per kilowatt hour;
- biomass (landfill gas) @ 8.5026 cent per kilowatt hour; and
- hydro and other biomass technologies @ 8.7455 cent per kilowatt hour.

However, it is not clear that the REFIT scheme in its current form, where the vast majority of uptake has been for generators greater in size than 1MW, is fit-for-purpose for all small-scale generators and inclusion in, for example, group processing may cause delays in uptake.

2.3. Technologies considered

The following small-scale technologies are considered under this review:

- **wind** – electricity from wind turbines;
- **AD** – electricity from biogas generated by microorganisms;
- **hydro** – electricity from water turbines; and
- **PV –** electricity from solar panels installed on roof tops.

[9] Source: Department of Communications, Energy and Natural Resources: http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/REFIT.htm

More details about each technology are given in Section 4.

The NIRO of course covers a number of other technologies including biomass, wave and tidal. These were specifically excluded from our terms of reference. Note also that we only considered PV up to 250kW. Larger scale PV was considered by DETI initially in 2012/13 and a further consultation was recently concluded[10] and again was specifically excluded from our terms of reference.

2.4. Summary

In conclusion, we can see that the NIRO has already stimulated significant small-scale renewable generation in NI. Even at current levels, it contributes around 10 per cent of NI's renewable electricity, likely significantly more than small-scale generation will to the equivalent GB target. There is also more of a focus on onshore wind than in GB, although the PV sector is growing rapidly and there may be convergence with the GB experience.

We note that in the neighbouring GB and ROI, small-scale renewables are supported by FITs rather than a renewables obligation or similar subsidy mechanism. We understand that by later this decade, NI will shift to a FIT, meaning that the NIRO has a limited life. While the design of the FIT is beyond the scope of this report, we note that if there is to be any overlap between the NIRO and the FIT, DETI considers that it will be "*important that both mechanisms offer similar incentive levels*"[11].

[10] DETI, January 2014, Government Response to the consultation on proposed changes to the Northern Ireland Renewables Obligation on ground-mounted solar PV above 250kW *http://www.detini.gov.uk/government_response_to_ground-mounted_solar_pv_above_250_kw_consultation.pdf*

[11] ibid

3. APPROACH

In this section we describe the approach we took to this work. We essentially followed a two phase approach, which we describe below.

Before doing so, however, we set out here our overall approach to determining ROC levels. This can only be done by focusing on the fundamental purpose of the RO, which is to provide support to cover the additional technology costs of renewables, and support their deployment. This deployment helps to reduce carbon dioxide emissions and to achieve the UK's 2020 renewables target.

However, if deployment in the short term were the only objective, the most rational approach would be to subsidise only the most cost-effective technologies, or at least focus subsidy on those. As will be seen later in our comparison of NI costs with those in other countries, the Netherlands takes this approach, providing subsidy first to those technologies that need the least, and only if funds remain providing subsidy to other more expensive ones.

Short-term deployment is, however, not the only valid objective. Subsidy can also be intended to promote technological development (and subsequent cost reduction) in relatively immature technologies, or to develop the market for them. Other wider purposes such as public engagement are sometimes suggested. To achieve these purposes, subsidy levels might vary by technology.

When considering these benefits, however, it is important to understand the impact that subsidy might have on the markets for different renewable technologies in Northern Ireland. Because of the region's relatively small size, technological development is unlikely to be driven to a significant extent by subsidy within NI. A greater impact is possible on NI markets for different renewables technologies, but markets do mature over time and the rationale for subsidy reduces somewhat.

Weighed against these potential benefits of deployment is the financial cost of the subsidy, which (in the case of the NIRO) increases consumers' electricity bills. Concerns about these costs have been increasing over recent years, and need to be given proper weight in deciding whether a subsidy level for a particular technology – and in particular, subsidy *increases* – are justified.

These considerations – and the fundamental purposes of the RO, to compensate for technology cost differences - will be kept in mind in our analysis. We focus on changes in technology costs, but do not (for reasons set out below) propose using the RO to compensate for changes in grid connection costs, for example. However, we do realise (as discussed above) that any changes to the RO banding levels need to respect cost-effectiveness, and need to take into account the impacts on consumer bills, administration costs and the Levy Control Framework, as well as wider considerations such as employment and consistency with the rest of the UK.

This concludes our discussion of the broad basis of our approach. We now turn to a description of the detailed steps that we took.

3.1. Phase 1

This phase involved gathering data on technology and financing costs, as well as other data and assumptions such as electricity price projections.

We used the following data sources to provide cost and deployment data:

- market intelligence received from DETI (both formal consultation and responses and data received through other channels);
- publicly available reports, data and analysis;
- data gathered from stakeholder consultation; and
- in-house cost data.

A list of (public) data sources used is provided in Annex A. This exercise covered both the data for the NI market and for other markets (to assist with the benchmarking exercise). We took the range of data points for each technology and collated these to present past, current and future costs as ranges with a high, central and low case value for each parameter. The central case represents the most typical value, while the low and high values represent the limits of the reasonable range based on an evaluation of the data available. These were developed based on our judgement of the balance of the different factors and the inputs gathered from stakeholders. The high case, for example, is based on a combination of factors tending to result in higher prices; for example, strong global demand for the equipment, high material prices, and low local deployment levels leading to lower competition/economies of scale.

Our detailed assumptions are shown in Annex B.

3.1.1. Electricity price and related assumptions

These are crucial assumptions for determining the appropriate level for each ROC band. We have used the most up to date DECC figures for fossil fuel and carbon prices. For electricity market prices, we reviewed the market price scenarios developed for our previous work for DETI earlier in 2013 to understand whether anything has changed that would materially affect them.

3.1.2. Cost of capital assumptions

Estimating the cost of capital assumption for alternative generation technologies and energy sector investors was a particularly critical important part of the economic viability analysis. It is more difficult for small-scale generation as this is often installed by households, which are known to have quite different costs of capital than large businesses. Our starting point here was our analysis for DETI on the most appropriate form of subsidy for small-scale renewables in NI, which was published earlier this year. We identified whether this needed to be updated in the light of developments since that report, and cross-checked our findings with stakeholders.

3.1.3. Calculation of levelised costs and possible updated ROC bandings

DETI's existing economic model, which was developed by CEPA, calculates levelised cost figures for renewable technologies. This is based on capex and opex figures from our data gathering described above.

Levelised cost is calculated as total lifetime cost, appropriately discounted, divided by discounted lifetime expected generation. An example is shown in Box 3.1 below. All figures are purely illustrative.

Box 3.1: Example of levelised cost calculation

> Assume for simplicity that a 1MW renewable generator has an initial capex cost of £2m, and annual operating costs of £50,000 in years 1 to 10. Assume that it produces around 2,500MWh per year – representing a load factor of 28.5%. Finally, assume that the developer has a required rate of return of 10%.
>
> The lifetime cost of the generator turns out to be just over £2.3m. The generator's discounted lifetime output is 15,361MWh, and so the cost per MWh is just over £150.

Based on the calculated levelised cost figures, we identify the additional levelised cost of each of the four renewable technologies, compared to the projected electricity price, and identify the required level of subsidy to make each economic, in £/MWh. This is converted into a number of ROCs. We then compare this with the same calculation using existing figures to identify by how much the requirement for subsidy has changed. This is used to make an initial indication – based purely on changes to our cost assumptions – as to how ROC bandings should change.

3.1.4. Subsidy levels and deployment

We also, as required by our terms of reference, compared deployment and subsidy levels against those in four other countries: GB, ROI, Denmark and the Netherlands. The aim was to identify any significant differences between deployment and subsidy levels between NI and the other markets and where possible to comment on the reasons for this.

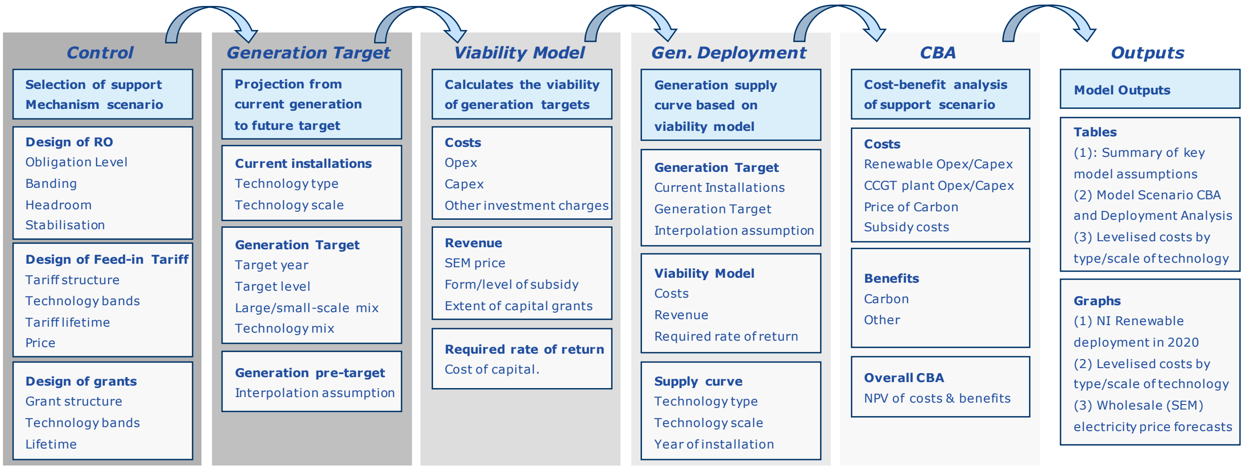
3.2. Phase 2

The objective of this phase is, broadly, to determine the costs and benefits of any changes to ROC banding suggested by Phase 1, and to benchmark the resulting revised ROC bandings and associated costs against those in GB, the ROI and two other European countries.

Our approach to this phase is based on the economic model that we have previously developed for DETI and used on projects such as our analysis of the suitability of a FIT for small-scale renewables. This model allows us to assess the quantitative impact of changes to technology costs and bandings, in terms of deployment, overall cost and impact on consumer bills. We supplement this with a qualitative assessment of impacts.

Since the model has previously been supplied to DETI, we do not present a detailed description here. Figure 3.1 below shows the main sections of the model and the flow of calculation from left (control, inputs, assumptions) to right (outputs including costs and benefits).

Figure 3.1: Outline of existing DETI NIRO model



As can be seen, the model provides estimates of impacts in terms of an overall net present value (NPV) of costs and benefits, as well as more specific metrics such as deployment levels. More detail about the model can be found in Annex C.

Sensitivity analysis

In project and policy appraisals there is always likely to be some difference between what is expected, and what eventually happens because of risks and uncertainties which materialise. A key technique for assessing uncertainty is sensitivity analysis. We used this to examine how the benefits of changing the ROC levels are affected by reasonable variations in key assumptions, and whether this would change the decision about whether to change the ROC bandings. These assumptions include prices, technology costs and required rates of return.

The sensitivity analysis was done using the economic model. We also qualitatively considered the plausibility of the assumptions we have made for the model to evaluate the confidence we can have in the model outcomes.

3.2.1. Non-quantified impacts

In addition to the quantified impacts from the model, there are a number of other areas where we assess the potential impact. We set out key ones below, with a brief description of how we assess them and initial views on their likely importance.

Impact on the SEM

The impact on the SEM will be driven by the level of deployment to 2020. We compare this with what deployment would have likely been under a continuation of current banding levels. There also needs to be some consideration of whether the funding for large-scale renewables will stay the same or will be increased.

We do not expect the impact to be large.

Economic benefits to NI

There may be some benefits to NI in terms of an increased market for locally produced renewable technology, or from skilled installers. CEPA considered a similar issue as part of its work for DETI on the Renewable Heat Incentive.

We would compare the level of deployment expected from each option with that from current NIRO bands, and identify whether it would be likely to lead to a significant increase or decrease in the requirement for installers in particular.

Grid capacity, supply chain and other impacts

In this section we consider the impact of different deployment levels on issues such as grid capacity and supply chain. This was limited to high-level qualitative impacts (detailed grid capacity or supply chain analysis is beyond the scope of this study). We also considered issues such as potential distortions between NI and the ROI.

3.2.2. Comparison with other policies

As required by the terms of reference, we benchmarked our results by comparing the cost-effectiveness against other policies.

Our economic model looks at deployment levels, carbon savings and total subsidy costs. On this basis we are able to estimate approximate cost-effectiveness metrics for the policy, in terms of carbon savings per pound of subsidy. This can be compared to that for other subsidies such as the Renewable Heat Incentive (in NI and in GB) as well as to other renewable electricity subsidy regimes where available. The source for this would be either our own cost-benefit assessments for the RHI, or impact assessments by DECC and where available others, which would be expected to include estimates of carbon savings and total subsidy costs.

4. ASSUMPTIONS AND DATA

In this section we set out the assumptions and data that form the basis of our analysis. Our sources are listed in Annex A, with our assumptions in Annex B. In this section, we present a description of the type of information gathered and of the main differences between our current data / assumptions and those used for the previous NIRO banding. In each case we discuss the level of uncertainty, which fed into the sensitivity analysis we conducted.

We start with technology costs, then move on to financing costs. Finally, we discuss changes to assumptions such as electricity price projections, which feed directly into the level of subsidy required.

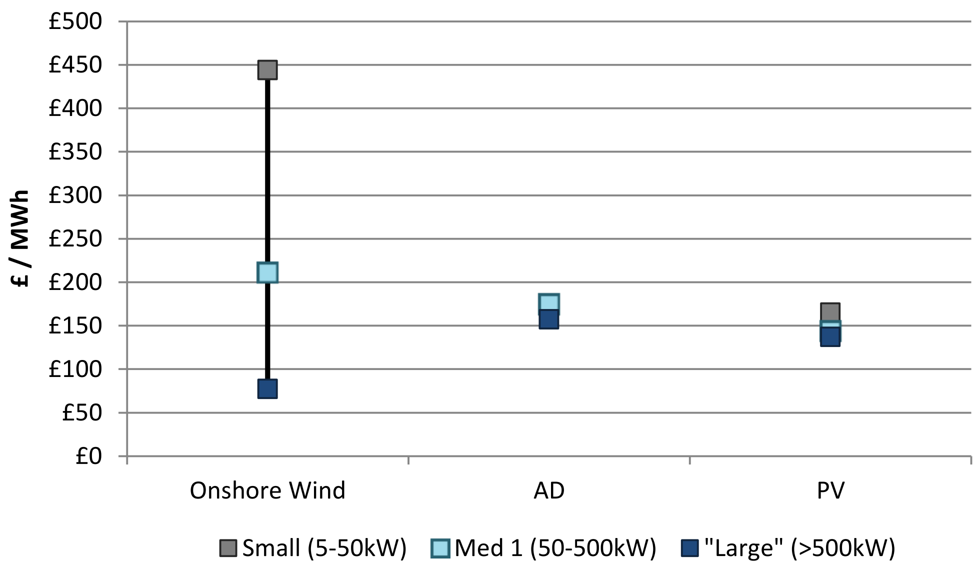
4.1. Technology costs

This section presents capital and operating costs, by technology, for the four technologies considered. We present current costs and estimates of likely costs in the 2014/15-2016/17 period. Fuel costs for the technology that requires it, anaerobic digestion (AD), are also presented.

Future technology costs are inherently unpredictable and so it is not possible to be certain that the true costs will be at the levels set out below. We have included ranges of uncertainty around each cost figure to reflect this.

Before entering into the detail of each technology cost, we present below a graph showing previous assumptions on the levelised cost of each technology, split by size. This is presented as Figure 4.1. These are based on the figures used in our economic model.

Figure 4.1: Estimates of levelised cost of technologies



For the technologies shown, small-scale generation has higher levelised costs than larger-scale. This difference is most marked for wind, although it is also clear for PV.

One key implication is that the financial cost-benefit implications of not subsidising small-scale renewables are likely to be positive – whether the alternative is no subsidy, or providing the same level of subsidy but to large-scale renewables. This should be borne in mind when reviewing the cost-benefit analysis.

We now turn to our estimates of current and likely future costs, by technology. We start with onshore wind, as it provides the majority of the capacity in NI.

4.1.1. Onshore wind

Capital costs for wind have shown some increases since 2010, with the greatest increase being in the 5-50kW band. These increases are a result of a number of factors including increases in turbine costs and more expensive grid connections. A number of stakeholders interviewed for this report also commented that second hand turbines are now no longer available which has tended to push up average prices. In addition, there are now fewer turbine manufacturers and models at some scales which may have reduced competition and allowed turbine costs to rise.

Note that there are differences between 2010 and today in the typical turbine sizes used for the 5-50kW and >500kW. In both cases, turbine sizes are now assumed to be somewhat smaller (based on indications of what is most commonly being installed). This is likely to have increased the cost per kW and contributed to the cost difference reported here.

Future wind capital costs are expected to show some increase over the period to 2017, as a result of on-going increases in equipment costs. There was also an expectation among stakeholders that grid connection costs will continue to increase, although it is acknowledged that current efforts between NIE and the industry may mitigate this.

4.1.2. Solar PV

Capital costs for solar PV are now significantly lower than in 2010, reflecting the significant cost reductions seen worldwide for this technology during that period.

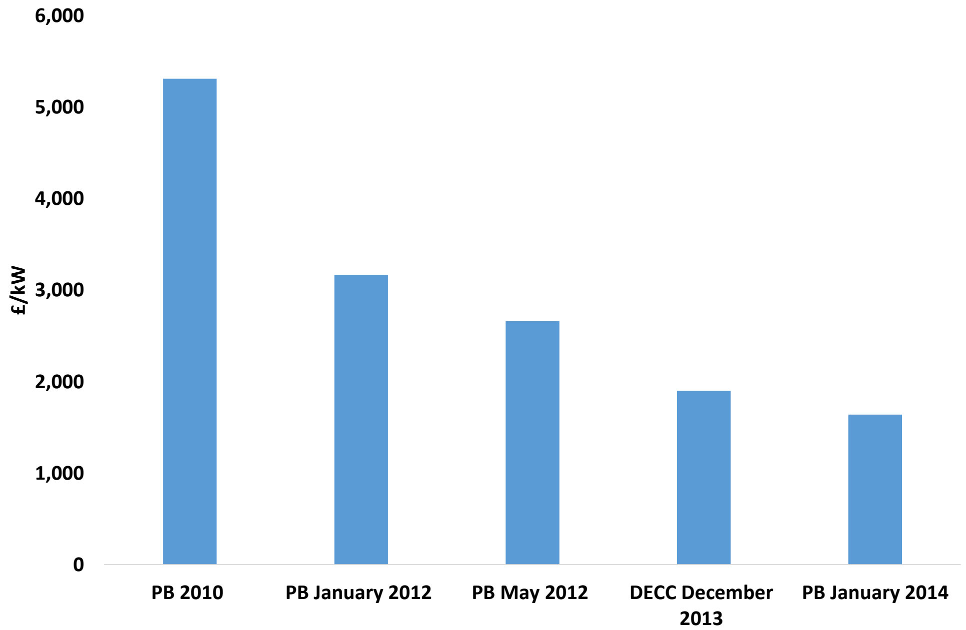
The costs identified in Section 4.1.5 below reflect this. Note that the 2013 costs are generally in line with those reported by stakeholders interviewed for this report.

Future solar PV capital costs are expected to continue to decline in the period to 2017, albeit at a slower rate than seen in the 2010-2013 period. This reflects a combination of the on-going competition in the global PV module market and better, lower-cost technical solutions.

Comparison with GB and historic estimates

It is clear that these figures have dropped substantially since the 2010 estimates. Indeed, they have also dropped substantially since the estimates made in PB's 2012 report[12] for DECC. However, they are not dissimilar to DECC's December 2013 estimates, with a central case for the capital cost of <4kW PV in 2016 of £1,900 per kW[13]. The downward trend is shown in Figure 4.2 below. Note that PB's figures were used by both DETI and DECC as the basis for their analysis of PV costs.

Figure 4.2: Trend in PV[14] costs over time



As this makes clear, our estimates are not out of line with those from DECC and are on a continuing downward trend.

Changes to connection process

In considering the costs for PV, we are mindful of the fact that there are a number of factors affecting these costs including installation requirements. Specifically, here, we understand that there will be new installation requirements for small-scale PV as a result of changes[15] to the installation thresholds set by NIE. The key change is that the threshold for (singe phase) installations requiring a full technical assessment under the G59 connection process (rather

[12] PB, May 2012, *Solar PV cost update* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/43083/5381-solar-pv-cost-update.pdf

[13] DECC, December 2013, *Electricity Generation Costs,* page 60 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

[14] Figures shown are capital costs for <=4kW installation. Figures are in current prices. Source: PB, DECC

[15] http://www.nie.co.uk/Connections/Generation-connections/Microgeneration/Statement-on-Changes-to-G83-Microgeneration-limits

than the less complex G83 process) will drop to 3.68kW. However, this is set based on the inverter, and the maximum installed generating capacity allowed is 4kW. For example, NIE has clarified that "*a standard 3.98kWp solar PV installation using a certified 3.68kW rated inverter would be acceptable*"[16].

The impact of this is that costs for 6kW installations can be expected to increase, and so we might expect a reduction in the number of these and a shift to 4kW installations.

4.1.3. AD

Capital costs for AD are slightly lower than those reported in 2010 as a result of a maturing market with greater access to established European manufacturers.

Future capital costs are expected to remain flat overall. There may be potential for further reductions in equipment costs but equally there may be upward pressure on prices if labour and material prices rise.

4.1.4. Hydro

Hydro capital costs are higher than reported in 2010. There are a number of reasons for this:

- Hydro project requirements (and therefore costs) are highly site-specific with only a limited number of potential sites being available. There is a tendency for the most attractive (i.e. lowest cost) sites to be developed first, increasing the average cost for the remaining potential sites which tend to be more remote and have less favourable energy resource characteristics.
- Grid costs are reported by stakeholders to have increased significantly. This reflects a combination of higher grid connection costs in general but also the remoteness of remaining undeveloped sites which as well as higher general construction costs (see above) will tend to result in a more expensive grid connection
- Stakeholders report that the requirements of the planning and consenting process have increased, pushing up development costs

Note that, given the site-specific nature of hydro projects, there is a particularly wide range of potential capital costs and this is reflected in the cost ranges reported in Annex B. There are likely to be projects with costs that are considerably lower than the central case estimate shown in Table 4.1 (see below), but there will also be projects whose costs are significantly higher.

For the period to 2017, hydro costs are expected to increase slightly as more viable sites are developed. As a mature technology, hydro is not expected to benefit from technology or market improvements that would result in cost decreases.

[16] ibid

4.1.5. Summary

A summary of the changes in capital costs (the major cost driver) is in Table 4.1.

Table 4.1: Capital cost changes since 2010[17]

Technology	Size Band	Current estimate (central case)	2010 estimate	% increase/ (decrease)
Onshore wind	<5	6,500	5,311	22%
	5-50	6,500	3,187	104%
	50-500	3,100	2,656	17%
	500-5000	2,200	1,593	38%
AD	50-500	4,750	4,993	-5%
Hydro	<5	10,000	5,311	88%
	5-50	8,400	4,249	98%
	50-500	6,800	3,187	113%
	500-5000	3,500	2,656	32%
PV	<5	1,640	5,311	-69%
	5-50	1,243	4,568	-73%
	50-500	1,060	4,249	-75%
	500-5000	1,000	3,718	-73%

Detailed data tables including low and high cost estimates are provided in Annex B.

4.2. Financing costs

This section covers another major driver of the levelised cost of renewables, namely the cost of finance. We have spoken to developers and lenders about this, as well as drawing on our own previous analysis for DETI.

Our analysis suggests that there are broadly three routes for financing renewables in NI: farmers financing them with a loan secured on their land, commercial developers financing them on balance sheet, and households financing them from their own funds. We understand that some are financed on a project finance basis by private equity but that this is rare. Indeed, this relative lack of a project finance option for renewables in NI was highlighted as a significant barrier by one of the individuals we spoke to.

We now discuss the three main financing routes, looking at what the financing costs and required costs of capital might be for each.

[17] Source: PB. 2010 estimates have been inflated to 2013 prices for comparison purposes.

4.2.1. Farms

An analysis of Ofgem's ROC register[18] shows that a large number of sites are on farm land. We might therefore expect farms to be a significant sector. Conversations with individuals active in the market, however, point to a more complicated picture. Many of the installations on farm land – particularly wind - have been developed by a third party, which leases the land from the farmer. One lender we spoke to suggested that around half the applications they were seeing were from farmers themselves, and the other half were from third party developers.

Our research into the terms being offered to farmers for installing wind turbines on site suggests that farmers might expect to secure a loan for around 70-90% of the total project cost, once planning consent has been achieved. The farmer would need to fund all pre-installation costs themselves (estimated at around £100k). The loan would be offered at around 6-7%[19], and would be secured on land or property. There would be an expectation that the farm could repay the loan even if the wind turbine failed. In other words, the loan is to the farm not to the project.

In terms of finance secured on the project, our research suggests that this will not happen until the project is generating. Lenders appear to be unwilling to take the risk of construction or connection delays and the consequent potential reduction in the number of ROCs that the project would receive, as a result of a banding review.

Part of this may reflect the slightly increased risk from the RO, with its variable payment stream rather than the fixed payment stream of a FIT. In any case, it is not out of line with information on the costs of finance for GB renewables generation.

Based on the above, we are not aware of any substantive evidence to suggest that farmers in NI face noticeably higher finance costs than GB renewables installers.

4.2.2. Commercial developers

In our report for DECC we suggested that commercial installations would require a return of around 5-8% (pre-tax, real). More recent work[20] for DECC has produced similar figures, albeit for large-scale onshore wind.

One issue with this figure is that it applies to GB. We therefore need to consider whether it is also applicable to NI.

In short, our research indicates that GB-based developers are entering the NI market. In order for them to do this, they are likely to be expecting a return in NI at least the same as the one they are getting in GB. In other words, the revenue from the NIRO for an installation

[18] https://www.renewablesandchp.ofgem.gov.uk/

[19] Typical figures from our research and conversations with stakeholders. We were quoted figures below 6% and one individual quoted figures of 8% and above.

[20] NERA, December 2013, *Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime*

in NI offers at least as good a return as revenue from the GB FIT, for an installation in GB. Since (as discussed earlier) support under the RO is approximately comparable to that under the GB FIT, this suggests that the GB FIT tariffs offer the same or better returns to aggregators in NI as they do in GB. This does not, therefore, in our view provide any reason for modifying them for NI.

4.2.3. Households

The next category we consider is residential investors. We also considered these in our work for DECC on small-scale FITs, where we suggested that they are likely to require a return somewhere between 0% and 20% (real).

The top end of this wide range was based on the very high discount rates that the literature[21] suggests are often applied to energy efficiency improvements. The bottom end was set by reference to the alternative investments available to households, which at present offer a relatively low return. This approach is consistent with the view expressed by stakeholders that householders installing PV were treating it as an investment and therefore as an alternative to other investment opportunities open to them.

We also note that there are opportunities for those homeowners who have some savings or equity to finance renewables through taking out or extending mortgages on their property. This can be done at what is effectively a real interest rate of 0%[22]. We therefore consider that while this is a wide range, it is possible to identify households at both ends of the range.

That said, there is a significant divide between those households able to raise money very cheaply (e.g. by extending their mortgage) and those which can only raise capital at higher rates or cannot raise it at all. Anecdotal evidence from GB suggests that wealthier households – which can raise money more cheaply - are more likely to take up renewable energy subsidy.

It is therefore likely to make sense to focus on wealthier households – that is, those with significant equity. Stakeholders largely (although not completely) concurred with this view. Some felt that the growth in companies offering to install rooftop PV for no upfront cost mean that all households were potential installers. However, when looking at financing costs, we need to look at who is raising the finance, not who is providing the site for the installation. In the case of developers installing solar PV on domestic roofs, they will be seeking a *commercial* rate of return, not a *household* one. Such installations therefore are covered by the discussion of commercial rates of return in the previous section.

[21] See for example, NERA & AEA for DECC, July 2009, *The UK Supply Curve for Renewable Heat*

[22] The Co-Operative Bank at the time of writing this report was offering mortgage extensions of up to £20,000 to install technologies including PV. The rate was 1.5% over the Bank of England Base Rate, which translates to around 2%. This is almost exactly the same as the rate of inflation (2.2% - source: Bank of England). http://www.co-operativebank.co.uk/mortgages/energy-efficient

The next question is how large this segment might be. To estimate this, we look at wealth distribution in NI. This is shown in Table 4.2 below, which compares the level of savings in NI with those in England.

Table 4.2 Distribution of savings and investments by household

Amount of savings and investments	**% of households**	
	N. Ireland[23]	**England[24]**
No savings	52	32
Less than £1,500	10	15
£1,500 but less than £3,000	9	7
£3,000 but less than £8,000	13	14
£8,000 but less than £10,000	2	3
£10,000 but less than £16,000	4	7
£16,000 but less than £20,000	2	3
£20,000 or more	8	19
Total	**100**	**100**

The table shows that NI has a lower proportion of households with considerable savings / investment; that is, a lower proportion of households with £20,000 or more.

In short, the "wealthier households" segment appears to be smaller in NI than in England. Since much of the uptake of renewables in England appears to have been by wealthier households, it may be that domestic uptake as a proportion of households will be lower in NI. There is some evidence for this from the installation figures to date. In both regions, by far the most common installation at a domestic level is PV. In GB there have been 402,974 installations of PV at 6kW or below, which we assume is a domestic installation. This is an average of one per 150 people in the country. This compares with 1,286[25] in Northern Ireland, around one for every 1,400 people in the country. In other words, the relative prevalence of small (presumed to be domestic) PV is much lower in NI than in GB. On the other hand, this is still only a very small fraction of households with significant savings.

We next need to ask what rates of return wealthier households might be looking for. Rates of return lower[26] than commercial organisations are likely to be appropriate. In our previous work for DECC we suggested a range of 0-4% real, and we consider that this is likely to remain an appropriate rate, taking into account the alternative investments available to

[23] Source: Northern Ireland Family Resources Survey, Northern Ireland Department for Social Development.
[24] Source: England Family Resources Survey. See UK Department for Work and Pensions website.
[25] All PV installations under 6kW in NI from Ofgem ROC register, December 2013.
[26] In its response to the consultation on the Phase 2B comprehensive review of FITs, DECC noted that "*A common suggestion was that investors and homeowners would be looking for returns of at least 6–8%. A number of respondents also highlighted the fact that commercial projects, local authority projects and aggregated projects would need higher returns than domestic installations*"

such households. In our modelling, we have used the relatively conservative assumption of 3% as a central case.

4.2.4. Other market segments

As well as commercial and domestic installations, there may be installations by the public sector and by community groups. However, our discussions with stakeholders suggest that these are likely to be limited. We have therefore not considered them separately. We note that DECC has published a community energy strategy, which DETI, DARD and DOE is considering in preparation of a NI Action Plan.

4.2.5. Project versus corporate finance

In conversations with stakeholders, it has been clear that projects at the small-scale are financed on a *corporate* basis rather than a *project* one. One key impact of this is that those lending to renewables are really lending to the company rather than the project. For example, we understand that when lending to farmers looking to install wind turbines, banks seek full security for the loan and an assurance that it can be repaid by other farm earnings even if the turbine does not work. The bank therefore is not taking any view on whether the wind turbine project itself is viable – only whether the farmer is a good credit risk. This also relieves the bank of the need to understand the details of the NIRO.

4.2.6. Summary

Our assumptions about the required rates of return for the two key segments are summarised in Table 4.3 below.

Table 4.3: Assumed rates of return

Market segment	Required return	Central figure used in model	Comments
Households	0-4%	3%	Focus on wealthier households. A much smaller segment than in GB
Commercial developers/ farmers	5-8%	7.5%	The largest segment

Other segments such as the public sector and community groups have been judged to make a relatively low contribution to installed capacity and so are not considered further.

4.3. Power price, carbon price and carbon intensity

We have also updated the model's assumptions on future power and carbon prices. Taking carbon prices first, these are significantly lower than our previous projections, in line with developments in the carbon market. GB wholesale electricity prices have also been revised downwards, in line with DECC's latest figures, although the change is much less than for carbon prices.

Finally, our model makes certain assumptions about the future fuel mix for the SEM, in order to estimate the carbon intensity of the power that renewables displace, and so their assumed carbon benefit. Our assumed fuel mix for the SEM[27] now includes a small proportion of peat-fired power to 2020 and beyond, whereas the previous projections did not.

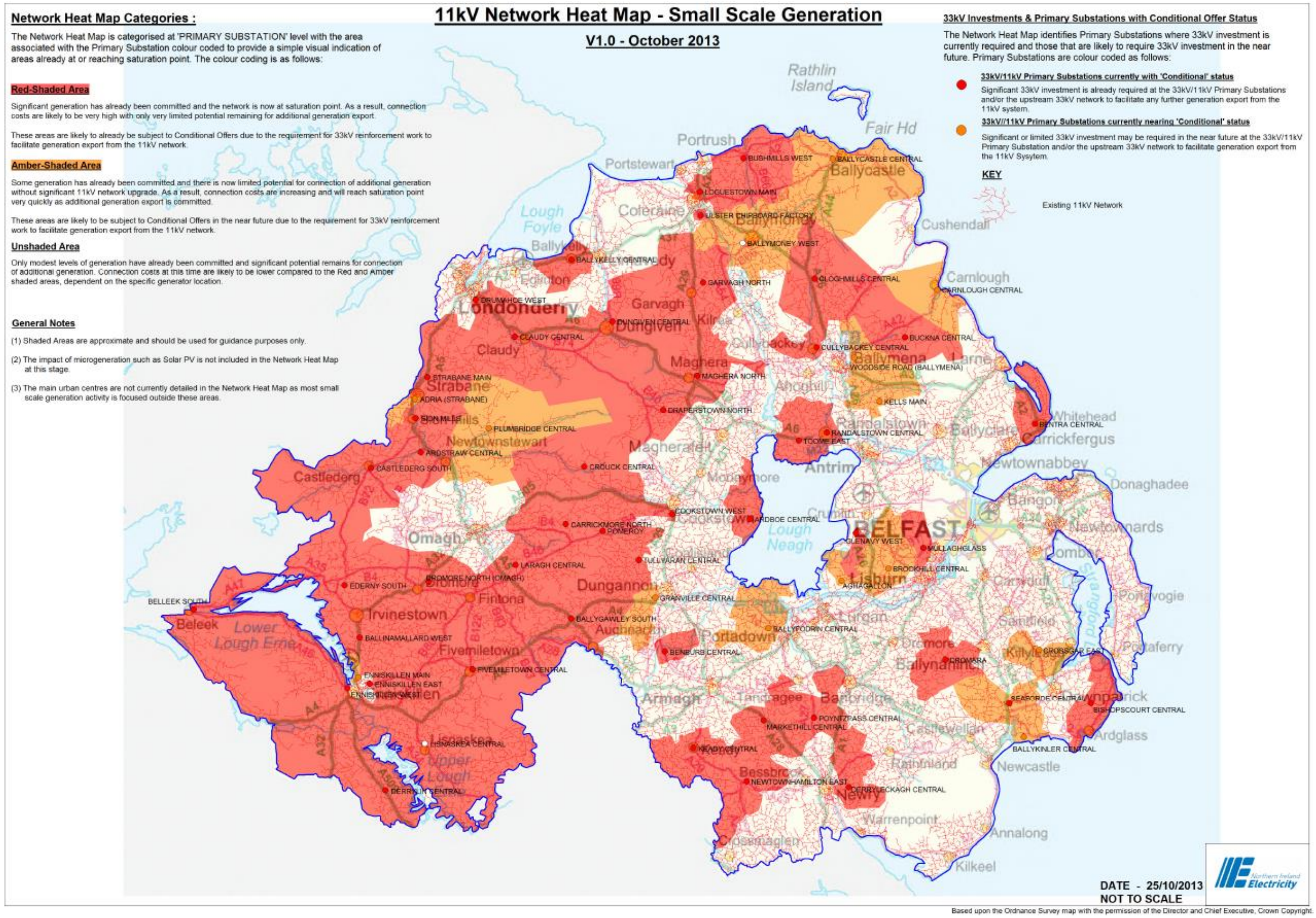
4.4. Deployment mix assumptions

Our economic model makes certain assumptions about how deployment is split between different installation sizes. We consider that this needs to be modified in the light of the issue of grid connection costs, which we now explore.

Grid connection costs have been raised by most of the stakeholders we spoke to, particularly those in the wind sector. Put simply, stakeholders have told us that the cost that the person or company installing the renewables will have to pay can vary widely depending on where the renewables will be installed and how congested the grid is in that area. The degree of congestion by area is shown in a heat map from NIE, which is reproduced as Figure 4.3 below.

[27] Fuel mix projections from SEAI

Figure 4.3: Network Heat Map – Small Scale Generation[28]



[28] Source: NIE, version 1.0, October 2013

As this shows, the level of congestion in the west of NI is very high. We understand that the true picture varies significantly even within the red areas, based on the local grid and sub-stations, but consider that this overview is helpful.

It would therefore be reasonable to assume that future deployment will tend to be further east than previously. An analysis of turbines installed in the east of the region suggests that they tend to be smaller than those installed in the west (based on location data from Ofgem's ROC register).

In our model we have an assumption about the size distribution of installed turbines. We propose adjusting this to show relatively smaller turbines being installed in future. Because of the uncertainties here we have used a central scenario and two sensitivities.

The implications of reflecting actual deployment to date, and of adjusting for potentially smaller wind turbine sizes, are shown in the tables below. The figures in the tables represent the proportion of total installed capacity (note: not number of installations) in each size band. Actual figures are based on figures from Ofgem's ROC register, with those sites commissioned before the start of the NIRO[29] removed.

We start with Table 4.4 for wind which shows that the overwhelming majority of capacity is at the >5MW scale.

Table 4.4: Deployment profile scenarios for (onshore) wind

Size band	Capacity (kW)	Actual profile to date	New central case	Sensitivity 1 (low small-scale)	Sensitivity 2 (high small-scale)
Domestic	**<5**	-	-	-	-
Small	**5-50**	1%	0.6%	-	1.0%
Medium 1	**50-500**	3%	5.7%	2.0%	6.0%
Medium 2	**500-5,000**	3%	3.2%	4.%	3.0%
Other	**>5,000**	93%	90.4%	94%	90%
TOTAL		***100%***	***100%***	***100%***	***100%***

This can be contrasted with the picture for PV, shown in Table 4.5 below, where all deployment is at the smaller end of the scale.

Table 4.5: Deployment profile scenarios for PV

Size band	Capacity (kW)	Actual profile to date	New central case	Sensitivity 1 (low small-scale)	Sensitivity 2 (high small-scale)
Domestic	**<5**	34%	40.0%	34.2%	45.0%

[29] 1 April 2005. Source: DETI

Size band	Capacity (kW)	Actual profile to date	New central case	Sensitivity 1 (low small-scale)	Sensitivity 2 (high small-scale)
Small	**5-50**	66%	60.0%	65.8%	50.0%
Medium 1	**50-500**	-	-	-	-
Medium 2	**500-5,000**	-	-	-	5.0%
Other	**>5,000**	-	-	-	-
TOTAL		***100%***	***100%***	***100%***	***100%***

Note that in one scenario we have included a small amount of large-scale PV.

The picture is somewhat similar for AD, as shown in Table 4.6. Here, all deployment is at the medium 1 and medium 2 scale (around 500kW). These figures are based on the eight currently installed sites in NI.

Table 4.6: Deployment profile scenarios for AD

Size band	Capacity (kW)	Actual profile to date	New central case	Sensitivity 1 (low small-scale)	Sensitivity 2 (high small-scale)
Domestic	**<5**	-	-	-	-
Small	**5-50**	0.5%	-	-	-
Medium 1	**50-500**	31.4%	100.0%	100.0%	100.0%
Medium 2	**500-5,000**	68.1%	-	-	-
Other	**>5,000**	-	-	-	-
TOTAL		***100%***	***100%***	***100%***	***100%***

Finally, hydro installations show a somewhat wider spread, as Table 4.7 shows.

Table 4.7: Deployment profile scenarios for hydro

Size band	Capacity (kW)	Actual profile to date	New central case	Sensitivity 1 (low small-scale)	Sensitivity 2 (high small-scale)
Domestic	**<5**	-	1.0%	1.0%	2.0%
Small	**5-50**	8%	75.0%	71.0%	80.0%
Medium 1	**50-500**	55%	24.0%	28.0%	18.0%
Medium 2	**500-5,000**	37%	-	-	-
Other	**>5,000**	-	-	-	-
TOTAL		***100%***	***100%***	***100%***	***100%***

It will be noted that the proposed scenarios show a somewhat smaller average installation than actuals to date. This is in line with discussions we have had with developers, who suggest that average sizes are reducing as the larger and potentially more profitable sites are used up.

4.5. Summary

The key changes from our previous assumptions are:

- reduction in PV capital costs; and
- a reduction in projected power and carbon prices.

All our updated assumptions form the basis for our quantitative analysis of the options (see next section for a discussion of the options).

In the next section, we compare renewables in NI against those in other European countries.

5. BENCHMARKING WITH OTHER COUNTRIES

As part of our work, DETI asked us to benchmark costs against those in other European countries, including GB, ROI and two others. We have chosen Denmark and the Netherlands as comparators due to their geographical similarity to NI (Northern European, extensive coastlines) and their relatively well-developed renewables sectors, with a high level of interest in wind and AD and a recent rapid development of solar PV.

We now briefly discuss the support regime for each country, before summarising the results of this benchmarking exercise.

5.1. GB

Small-scale renewables up to 5MW in GB are supported by a Feed-In Tariff (FIT) scheme that pays a fixed amount per kWh over 25 years. The level of the FIT payment varies according to the technology and the size of installation. A degression mechanism has been introduced to take account of changes in technology costs – the installed capacity for each technology and size band is monitored and the FIT for future installations may be adjusted downwards if there is a higher than expected capacity installed in a given period.

Note that projects above 50kW can choose to receive support under the Renewables Obligation rather than the FIT.

5.2. ROI

ROI operates a feed-in tariff scheme for renewables including wind, hydro and anaerobic digestion. Limited support for domestic scale projects (up to 11kW) is also available from Electric Ireland (ESB) in the form of a micro-generation export payment.

5.3. Denmark

Denmark supports small-scale renewables through a combination of feed-in tariffs and, for small-scale installations, net metering where net exports receive a premium tariff. This approach is currently being reviewed with a feed-in tariff for small-scale installations being proposed.

5.4. Netherlands

The Netherlands operates a feed-in subsidy approach, the “SDE+” which covers the difference between the cost of generation and the energy revenue received. There is an annual budget and projects are supported on first come first served basis, with projects applying for lower levels of support[30] receiving priority. For domestic-scale systems, a net

[30] Funding is provided in four rounds, with the support level in €/MWh increasing round by round. Each round is only run if not all the funding has been used up in previous rounds. Source: IEA

metering system is in operation. A grant scheme has also been used for small-scale solar PV installations.

5.5. Results

The results of the capital cost comparison between NI and the comparator countries are shown below in Table 5.1. Note that for some countries, there was no data available for some technologies or size categories (for example, there is no significant hydro market in Denmark).

Table 5.1: Capex for NI and comparator countries (all figures are £/kW[31])

Technology	Size band (kW)	NI central	GB	ROI	Denmark	Netherlands
Onshore Wind						
	<5	6,500	6,000	5,050	-	5,300
	5-50	6,500	5,500	4,000	-	-
	50-500	3,100	3,750	3,229	-	2,400
	500-5,000	2,200	2,000	2,420	1,100	1,100
AD						
	50-500	4,750	4,700	4,550	4,500	-
	500-5,000	4,500	4,500	-	5,500	4,650
Hydro						
	<5	10,000	10,000	7,500	-	-
	5-50	8,400	7,500	-	-	-
	50-500	6,800	6,000	-	-	4,200
	500-5,000	3,500	3,250	3,750	-	-
PV						
	<5	1,640	1,500	2,300	1,400	1,500
	5-50	1,243	1,150	2,400	-	1,160
	50-500	1,060	1,100	-	1,100	-
	500-5,000	1,000	1,000	-	1,600	-

The capex comparison shows that, broadly speaking, NI has similar costs to the comparator countries, with the central values for the other countries within the high-low range of the NI data.

[31] Figures for ROI and NL were converted using an exchange rate of €1.2 to the £. Figures for Denmark were converted using an exchange rate of 9.09 Danish krone to the £.

The data indicates that capex for smaller wind installations may be cheaper in ROI than in NI (or GB); however, the data from ROI was relatively limited and it is not clear whether grid costs are included. This may explain the cost difference.

AD capex is similar for NI and the comparison countries.

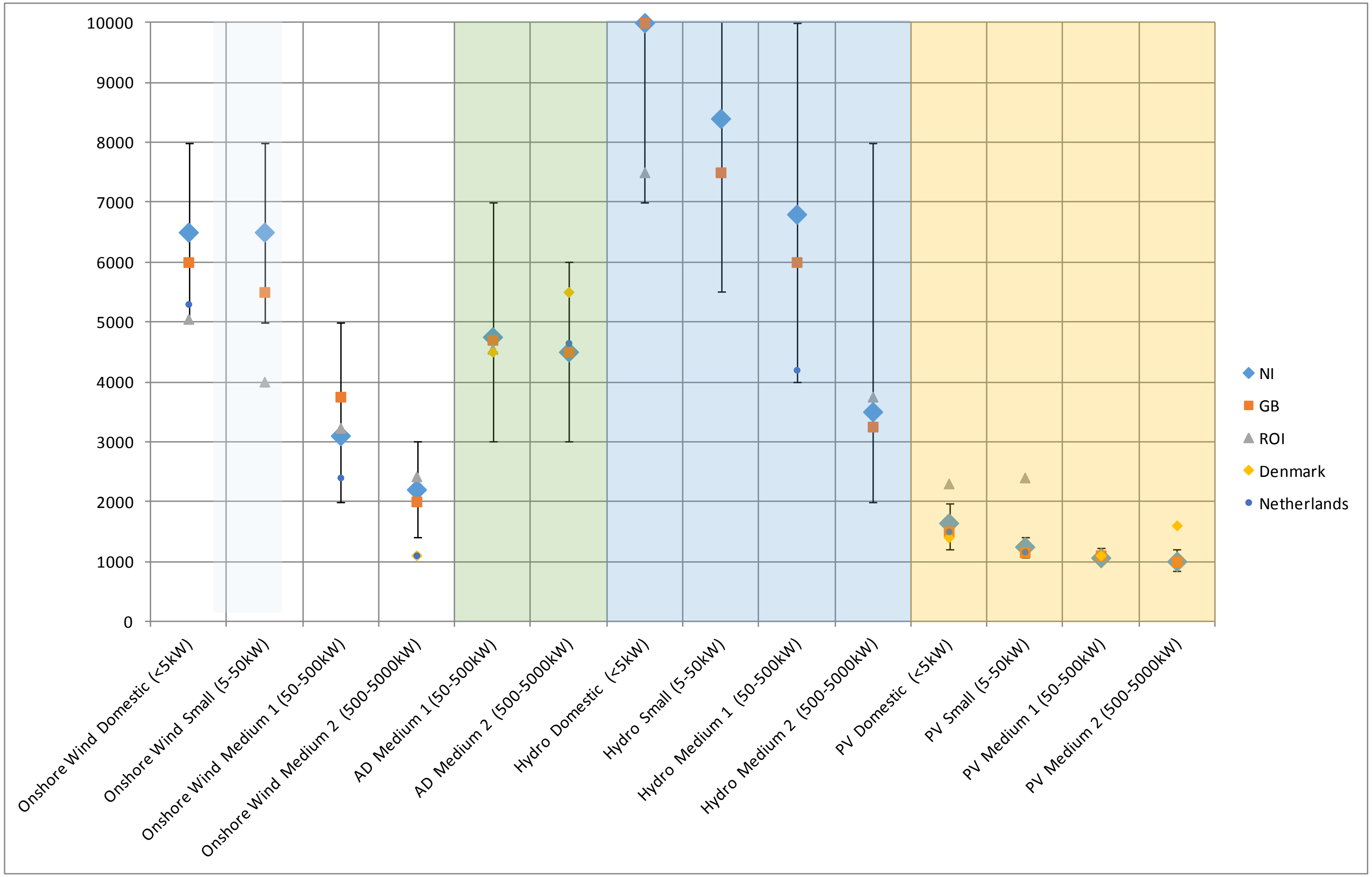
Hydro capex shows the wide range that is typically found for this technology as a result of the highly site-specific nature of projects costs. While some NI data is slightly higher than that for GB or ROI, we do not consider this to be a significant difference.

There are indications that solar PV in the ROI is more expensive than in NI or the other comparison countries. The PV market in ROI is much less developed than in NI or elsewhere, with significantly smaller total installed capacity, and this is likely to be a key factor in the higher costs.

The data also indicate that large PV in Denmark may be more expensive than in NI or GB; however, the available data is based on projected costs only (no systems at this scale exist yet in Denmark) and given the recent significant evolution in PV costs, this difference may not translate into different costs for actual projects.

The capex costs are illustrated in Figure 5.1 on the next page.

Figure 5.1: Capex costs for NI and comparator countries



Note: the error bars represent the high-low range for the NI data

We now present the corresponding figures for opex in Table 5.2. We have included opex data where available; however, we have focused the data-gathering for this comparison exercise on capex which is typically the more significant contributor to cost of generation for renewable energy projects.

Table 5.2: Opex for NI and comparator countries (in £/kW/year)

Technology	Size band (kW)	NI central	GB	ROI	Denmark	Netherlands
Onshore Wind						
	<5	60	70	76	-	-
	5-50	60	50	60	-	-
	50-500	60	50	-	-	-
	500-5000	30	30	-	-	26
		2,200	2,000	2,420	1,100	1,100
AD						
	50-500	800	850	-	-	-
	500-5000	700	700	-	-	744
Hydro						
	<5	160	160	-	-	-
	5-50	180	160	-	-	-
	50-500	200	130	-	-	315
	500-5000	100	100	188	-	-
PV						
	<5	27	32	-	-	-
	5-50	24	23	-	-	-
	50-500	23	23	-	-	-
	500-5000	23	23	-	-	-

The more limited opex comparison indicates that opex costs are also broadly similar between NI and the comparator countries.

Finally, we have compared the subsidy levels available in each country for the different renewable technologies. Results are shown in Table 5.3 below. Note that these data represent only the "headline" subsidy levels - the total incentive available may differ as a result of other incentives such as tax rebates or one-off grants (which were beyond the scope of this report to investigate).

Table 5.3: Subsidy levels for small scale renewables (in €c / kWh)

Technology	GB *	ROI	Denmark **	Netherlands ***
Wind	5.1 – 26.5	7.1	8.0 – 17.0	8.8 – 11.9
AD	11.3 – 18.5	10.4-15.6	11.0-21.0	7.0 – 11.1
Hydro	4.0 – 26.5	8.8	-	-
PV	7.9-17.7	-	8.0 – 19.4	7.0 – 14.8

* FIT levels for Jan 2014, converted to €c. Range represents the range of FIT levels for different size bands

** For grid connected projects. Different levels depending on length of subsidy period chosen (i.e. higher subsidies only available for a shorter period).

*** Funding in provided in rounds, higher subsidies apply to later rounds

Table 5.3 shows that the different countries generally offer similar levels of direct subsidy, although the structure of the GB FIT scheme with multiple size bands means that support for smaller-scale projects is somewhat higher than in the other countries.

6. OPTIONS FOR CHANGES TO ROC LEVELS AND BANDING

This section presents our suggested changes to the NIRO. These are driven by two questions:

- Have technology costs changed, which might suggest a need to change subsidy levels from the RO to compensate for the changed costs?
- Should there be new ROC bandings?

The following sections consider each of those questions in turn. In doing so, we are mindful of the framing discussion at the start of section 3. This looked at the objective of the RO, in terms of compensating for technology cost differences, and at the potential wider benefits of renewables deployment, but also looked at the increasing emphasis on costs. This leads us to be cautious before proposing cost increases, unless they have clear wider benefits.

6.1. Potential changes to reflect latest technology costs

Our approach to determining potential changes because of technology costs is as follows. We start with the technology costs used in our 2010 analysis for DETI. These are then compared with current costs and the change in levelised cost is calculated. This change is then converted into a number of ROCs. A worked example for 150kW wind is shown in Table 6.1.

Table 6.1: Worked example for change in levelised cost (all figures current prices)

	Units	Old	New	Difference	Comments
Capex	£m/MW	2.656[32]	3.10	0.444	The key variable
Opex	£m/MW/year	0.06	0.06	-	No change for this technology but could be for others
Lifetime	Years	20		-	These factors are constant
Load factor	%	20%		-	
Size	kW	150		-	
Discount rate	%	7.5%		-	
Discounted lifetime output	MWh	2,681		-	
Discounted lifetime cost	£	370,605	432,558	61,953	The NPV of capex and opex over the lifetime of the project, at the discount rate
Levelised	£/MWh	138	161	23	Discounted lifetime cost

[32] Our 2010 figure was £2,500 per kW in 2010 prices, which we have increased here to take account of inflation.

	Units	Old	New	Difference	Comments
cost					divided by discounted lifetime output

Since, using our updated assumptions, the levelised cost of 150kW wind has increased by £23/MWh, which amount to an additional 0.5[33] ROCs if the cost increase was to be fully compensated for.

Repeating this for all technologies gives us the ROC levels in Table 6.2. Note that the levels apply for 2015/16 and 2016/17.

Table 6.2: Comparison of current and possible new banding levels

		ROCs		
Technology	**Size Band**	**Current [34]**	**New**	**Comments**
Onshore wind	Up to 250kW	4	4.5	Driven by increase in capex
	250kW to 5MW	1	1	Limited evidence at this scale in NI
Solar PV	Up to 50kW	4	1.6	Uses different methodology to deal with very large drop in costs
	50kW to 250kW	2	1.6	Modified to fit with the lower band
Anaerobic Digestion	Up to 500kW	4	4	
	500kW-5MW	3	3	
Hydro	Up to 20kW	4	6	Significant increase in capex
	20kW to 250kW	3	4.7	Significant increase in capex
	250kW to 5MW	2	2.6	Significant increase in capex

This shows a small increase in support for wind at the smaller scale, due to smaller average turbine sizes and fewer refurbished turbines on the market. There is also a large increase shown for hydro, although as will be discussed later we are sceptical about the value for money such a change would represent. The most significant changes are to PV, which we discuss below.

Changes to PV ROC levels

When we compared the levelised cost of PV using our new capital cost assumptions with the levelised cost using the 2010 figures, the difference was so large that it suggested a subsidy level of less than 1 ROC. As a cross-check, we have considered the overall financial viability of PV at the sub-50kW level, taking into account future electricity price projections. This confirms the figure of under 1 ROC.

[33] We assume a ROC price of around £46/MWh

[34] Source: DETI, August 2012, *Government Response to the consultation on proposed changes to the Northern Ireland Renewables Obligation in 2013*

While we consider that the drop in capital costs inevitably leads to a reduced requirement for ROCs, we are cautious about proposing such a significant drop based on rapidly changing PV costs. We also note that it is well below the GB figure which is equivalent to around 2.5 ROCs (see Table 6.3), although that level is around the level set in 2012 when cost estimates were significantly higher (over the £2,000/kW mark). Finally, it is also below the 1.6 ROC figure that DETI has set for 2014/15 in its recent consultation[35] on systems over 250kW. For these reasons, we have proposed limiting the reduction such that subsidy levels for all PV are now at 1.6 ROCs.

It might seem strange that we are proposing having the same subsidy for all PV up to 250kW, since typically subsidy per kW and kWh increases as technology size reduces. This is driven by two factors: increasing capital cost per kW as size reduces and reductions in load factor reflecting the inherent economies of scale in the production electricity, given the technology.

The first of these is much less marked with PV than, say, with wind, as Table 4.1 showed. The second is also different between technologies, with (under our assumptions) the load factor for PV being the same for all sizes up to 250kW, whereas for wind it increases with size.

Finally, there are two factors tending to make small-scale technologies need less subsidy: different discount rates and the avoided costs of electricity purchases.

Recall that domestic discount rates are assumed to be lower than those for businesses, because households have relatively unattractive alternative possible investments. This means that households would, all other things being equal, require less subsidy to deliver acceptable financial returns.

In terms of avoided electricity cost, a much higher proportion of the output from the smaller installations is used on-site than for the larger installations. The value of using power on-site is equal to the *retail* price of electricity, while the value of sending the power off-site is equal to the *wholesale* price of electricity (or an export tariff). Retail prices are higher than wholesale, which makes the value of each kWh from a small domestic installation higher than from a stand-alone installation.

For all these reasons, we consider that a uniform subsidy level across all PV is not unreasonable, whereas it might be for, say, wind or hydro. There are also certain advantages in harmonising the subsidy across bands, in terms of reducing incentives to size PV systems to be just under the upper limit for a band.

It should be said that the figures in this table are options to consider, based on adjusting ROC levels to reflect changes in technology cost, rather than our final recommendations. We will go on to consider what the costs and benefits of these possible changes are before

[35] DETI, 2014, *Government Response to the consultation on proposed changes to the Northern Ireland Renewables Obligation on ground-mounted solar PV above 250kW*

making firm proposals. Before we do so, however, we consider whether there are other reasons to propose new ROC levels.

6.2. Changes to reflect other updated assumptions

We have also considered whether there is any reason to modify the ROC levels as a result of changes to other assumptions. We consider electricity prices, carbon prices and grid connection costs. We considered other assumptions such as cost of capital in section 4.2 but considered that these did not need to change.

6.2.1. Changes to electricity price, carbon price and carbon intensity

Since 2010, DECC's long-term projections of future electricity and carbon prices have fallen. However, we note that in DECC's 2011 banding review, a simplifying assumption was made that investors only have "*…five years of foresight of wholesale price changes, then assume the price stays constant in real terms for the rest of the project life*"[36]. This suggests that long term electricity price forecasts are unlikely to change the perspective of developers. Our understanding is that developers also tend to discount heavily any future revenues from electricity prices. Partly this reflects the uncertainty around future prices, but it also reflects the fact that at times of high renewables output, electricity prices are likely to be relatively low[37]. Finally, we note that in its 2012 assessment of PV banding[38], DECC did not consider electricity prices.

For these reasons, we do not consider that the changes to the long-term projections of electricity prices make a difference. Since carbon prices feed into investment decisions only through the electricity price, we also consider that changes to long-term projections of these should not drive changes to ROC levels.

However, the changes to our assumption about the future generation mix will change the carbon intensity of the SEM and so the assumed carbon savings from renewables. This feeds into our analysis of costs and benefits.

6.2.2. Changes as a result of grid connection costs

A clear message from our research was that grid connection costs have increased in recent years. One option that might be proposed to deal with this would be to simply increase ROC levels for all new wind generation to cover current connection costs. However, this is a very unattractive option, for several reasons.

[36] DECC, 2011, *Renewables Obligation Banding Review 2013-17*

[37] A typical comment is that "*the revenue split for small scale renewables is c.75% ROCs, 25% electricity*".

[38] DECC, 2012, *Renewables Obligation Banding Review for the period 1 April 2013 to 31 March 2017: Government Response to further consultations on solar PV support, biomass affordability and retaining the minimum calorific value requirement in the RO*. Table 1 lists the key assumptions considered

The first reason is simply the additional subsidy and hence cost. We understand that the *average* charge for a turbine at the 250kW level is around £250,000, with connection charges of £500,000 and above[39] being quoted. This is comparable to the cost of the turbine itself. To provide sufficient subsidy to make such projects economic, the number of ROCs for wind at 250kW or below would have to be increased significantly – as Box 6.1 below shows, by around 1.5 ROCs.

Box 6.1: Estimate of additional subsidy necessitated by higher connection costs

> Assume that we have a 250kW turbine, with a load factor of 30%. Total annual output in MWh is therefore 250*365.25*24*0.3/1000=657MWh. We assume a 20 year lifetime and a commercial discount rate of 7.5%, to give a total discounted lifetime output of 6,700MWh. A typical historic connection cost might be £50,000, so if the new cost is £500,000, there is an additional cost of £450,000. Spreading this over 6,700MWh gives an additional subsidy requirement of 67.14, which at a ROC value of around £45 is around 1.5 ROCs.

This would see wind at the sub-250kW level being given 6 ROCs per MWh (4.5 ROCs from our earlier proposals, plus 1.5). This is impossible to justify on cost-effectiveness grounds.

Even if the issue of cost could be overcome, there is a second problem, which is that making wind economic at these connection fees would increase the number of applications for new connections, and so be likely to put further upward pressure on connection costs.

Finally, we understand that there is a further issue with current connection offers in that many of them are *conditional* on future network upgrades. Since such agreements are unbankable because they are uncertain, simply increasing the level of subsidy will not make them bankable and so allow the projects to go ahead.

For all these reasons, we consider that increasing the number of ROCs for sub-250kW wind to cover connection fees is not a sensible option.

It should be said at this point that grid issues were identified as a major concern by almost all stakeholders we spoke to. While the question of how these can be resolved is out of scope for this project, we consider it is worth setting out here some of the ways forward that were discussed, such as:

- firm connection dates in connection offers;
- identifying situations where reducing the size of the installation would mean major reductions in the cost of connection; and
- considering whether alternative network management solutions could help to increase capacity – as has been done by some distribution network operators in GB.

[39] At least one stakeholder quoted a figure of over £1m.

This does not imply that we consider that any of these would be appropriate. We understand that NIE has been exploring smart grid projects and that a workshop with stakeholders has been planned for February 2014.

We also note that there is more than one way to calculate an appropriate cost for a grid connection. In particular, there is a question about where the connection boundary is for determining this cost. At present, we understand that the cost is calculated on a "semi-shallow" basis, where costs of any dedicated infrastructure plus any changes at one voltage level up are included. Other options include "shallow" connections (only dedicated infrastructure) and "deep" connection charging (full costs). The former would shift costs onto consumers, whereas the latter would shift costs onto the renewables installer. That said, any such change would not affect the total cost of the connection, but only who pays.

We return to this in our discussion of the grid cost implications of our options in section 7.

Implications

Based on the preceding sections, we have rejected a move away from a uniform 4 ROCs for sub-250kW wind across the whole of NI. The reality is that this is likely to lead to fewer installations in areas where the electricity grid is congested. It may also lead to generally smaller turbines being installed, since grid connection is likely to be somewhat less of an issue for smaller installations.

To reflect this in our cost-benefit analysis, we have adjusted the assumptions in our model about the proportion of turbines installed at each size band. Broadly, we have assumed that turbines in the 150-250kW range are less likely, and so there is an overall decrease in the small-scale capacity being installed.

6.3. Changes to the bands themselves

As well as considering whether the number of ROCs for each band needed to change, we also considered whether the bands themselves needed to change. We looked at whether there was a significant mismatch between the levels of support in NI and GB, and whether adjusting ROC bandings might correct for this. We also looked at whether banding needed to vary geographically to deal with the variation in grid connection costs.

We consider these two options in turn below. However, it should be stated upfront that a strong argument against adding any new bands is the additional complexity that new bands would bring to the NIRO. Given that the programme is already relatively complex, that a replacement small-scale FIT programme will be introduced by 2017 when the NIRO closes to new generation, a strong case would need to be made to include a new band.

6.3.1. Changes to bands – comparison with GB

Each technology has at least two size bands, on the basis that the subsidy requirement for technologies at different sizes is likely to vary significantly. There is a question about whether those bands are the correct width, and whether there are a sufficient number, in comparison to those in GB.

We start by asking what the corresponding DECC small-scale FIT bands are. These are shown in Table 6.3 below.

Table 6.3: DECC FIT levels for GB

Technology	Size Band (kW)	FIT[40] (p/kWh)	Approximate[41] equivalent in ROCs
Onshore wind	Up to 1.5	21.65	4.8
	1.5-15	21.65	4.8
	15-100	21.65	4.8
	100-500	18.04	4.0
	500-1,500	9.79	2.2
	Over 1,500	4.15	0.9
Solar PV	Up to 4kW	13.41	3.0
	4-10kW	12.15	2.7
	10-50kW	11.31	2.5
	50-100kW	9.99	2.2
	100-150kW	9.99	2.2
	150kW to 250kW	9.56	2.1
Anaerobic Digestion	Up to 250	15.16	3.4
	250-500	14.02	3.1
	Over 500	9.24	2.1
Hydro	Up to 15	21.65	4.8
	15-100	20.21	4.5
	100-500	15.98	3.6
	500-2,000	12.48	2.8
	Over 2,000	3.23	0.7

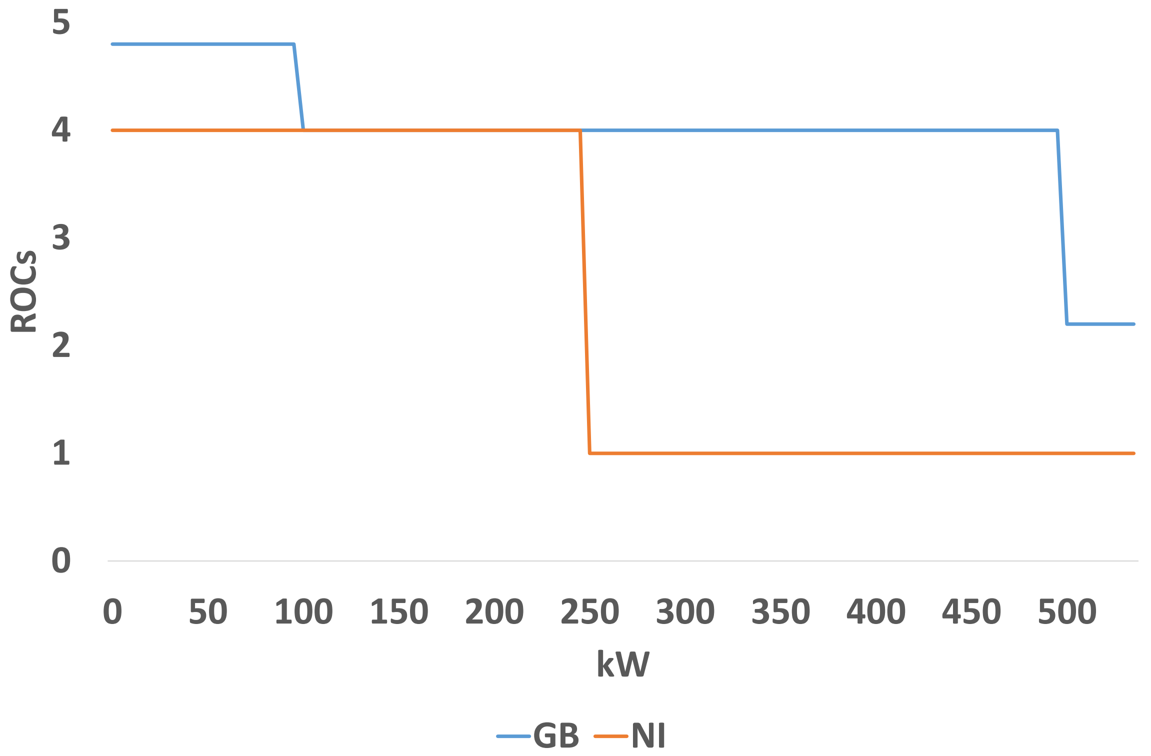
At first glance, there are significantly more bands than in NI, but note that many of the bands have the same or very similar level of subsidy to neighbouring bands. For example, all wind below 100kW receives the same subsidy, despite the fact that there are three bands,

[40] Source: Ofgem. Figures are for installations Oct-Dec 2013, middle rate figures for PV, figures for hydro 100-500kW are for installations after the "Conditional Date" (15 March 2013)
[41] Assuming one ROC is around 4.5p/kWh, and rounded to nearest 0.1 ROC. Note that this ignores the fact that those receiving the ROC can also receive revenue from the electricity price, whereas those receiving the FIT do not. It is therefore somewhat of an overestimate of the equivalent ROC level.

and the subsidy level for solar drops by less than 0.5p (around 0.1 ROC) as the 150kW threshold is crossed.

Because of the different bandings used in NI and GB, it is somewhat difficult to compare the level of subsidy in a table. It is easier to do so in a diagram, as the figures below show. We start with a comparison of subsidy levels for small scale wind in Figure 6.1.

Figure 6.1: Comparison of GB and NI subsidy levels for wind up to 500kW



As this shows, subsidy levels in GB (the blue line) are in most cases above those in NI (the yellow line). The major gap is in the 250-500kW band, although the difference persists even above 500kW.

This raises the question of whether an additional band of 250-500kW is appropriate for the NIRO. We note that this is a relatively small band in GB, with only 79[42] installations of this size to date, which contribute 1.6% of installed capacity under 5MW. Scaled to NI, this would represent only a handful of turbines.

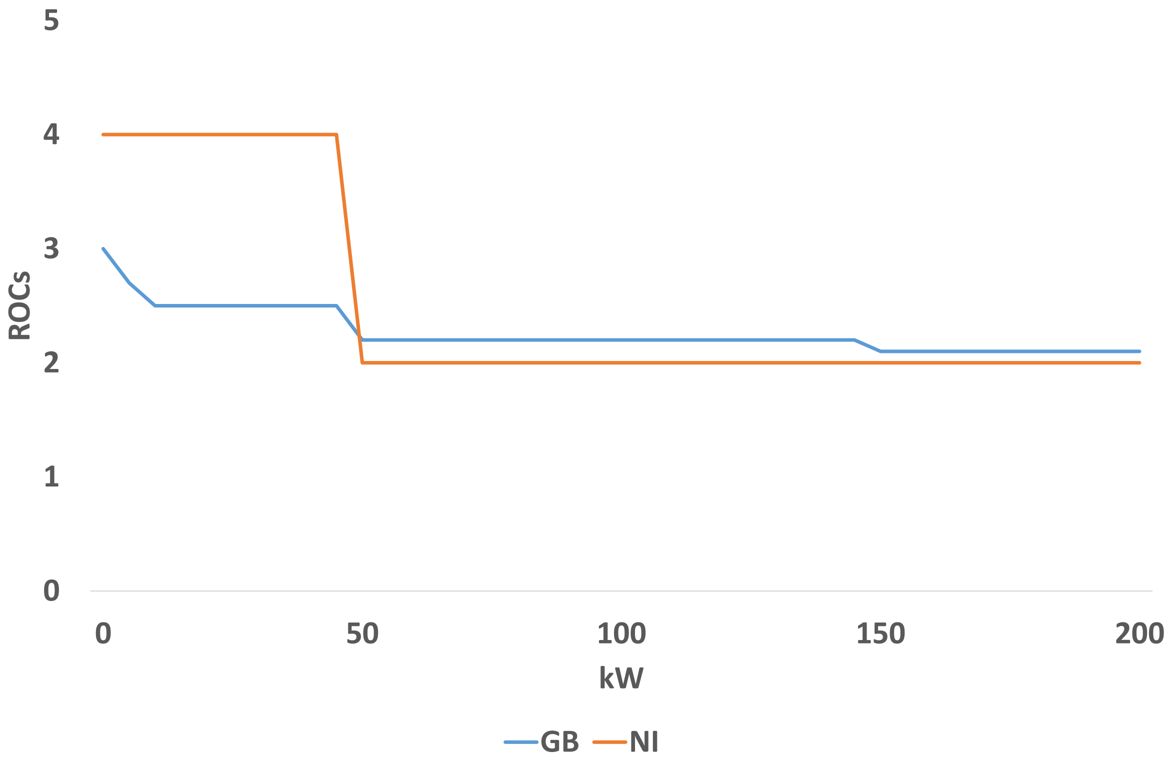
The benefits of providing this support would be to encourage relatively larger turbines, where possible. Longer term, equalising the subsidy levels between GB and NI might have benefits in terms of simplicity and clarity for developers. On the other hand, encouraging additional development at this level could lead to less development at other scales, particularly the largest scale.

[42] Source: Ofgem, October 2013, FIT installation report to 30 September 2013, https://www.ofgem.gov.uk/publications-and-updates/feed-tariff-installation-report-30-september-2013

We will analyse this option in more detail in Section 7.

Turning now to PV, the subsidy levels in NI and GB are compared in Figure 6.2 below.

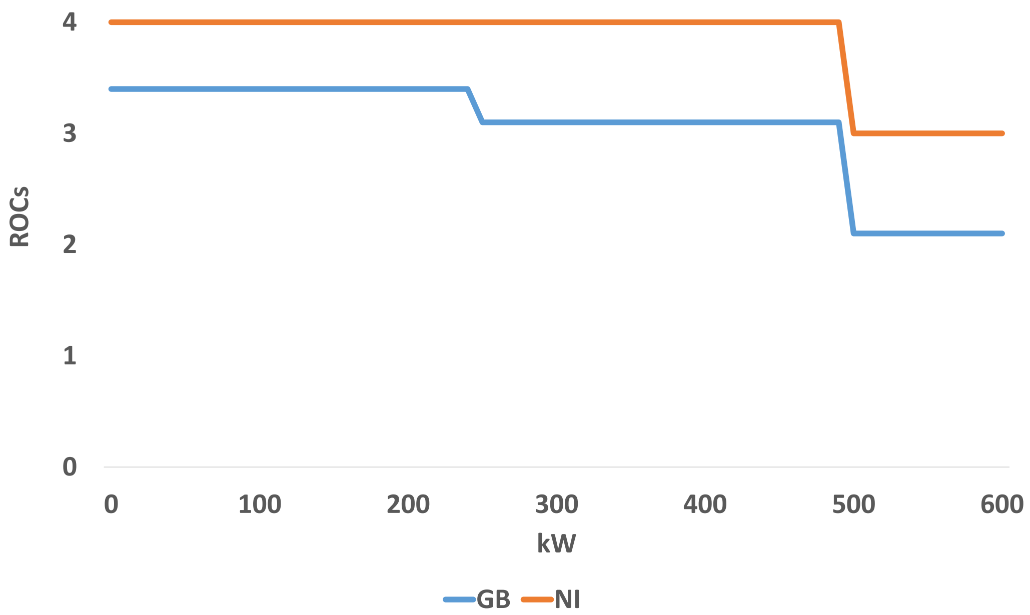
Figure 6.2: Comparison of GB and NI subsidy levels for PV up to 200kW



This shows that subsidy in NI is relatively high for installations up to 50kW, but that the difference between the regimes is negligible beyond that. We note that DETI has recently consulted on adjusting the rate for PV above 250kW (not shown here).

Turning now to other technologies, subsidy for AD is uniformly higher in NI, as Figure 6.3 shows.

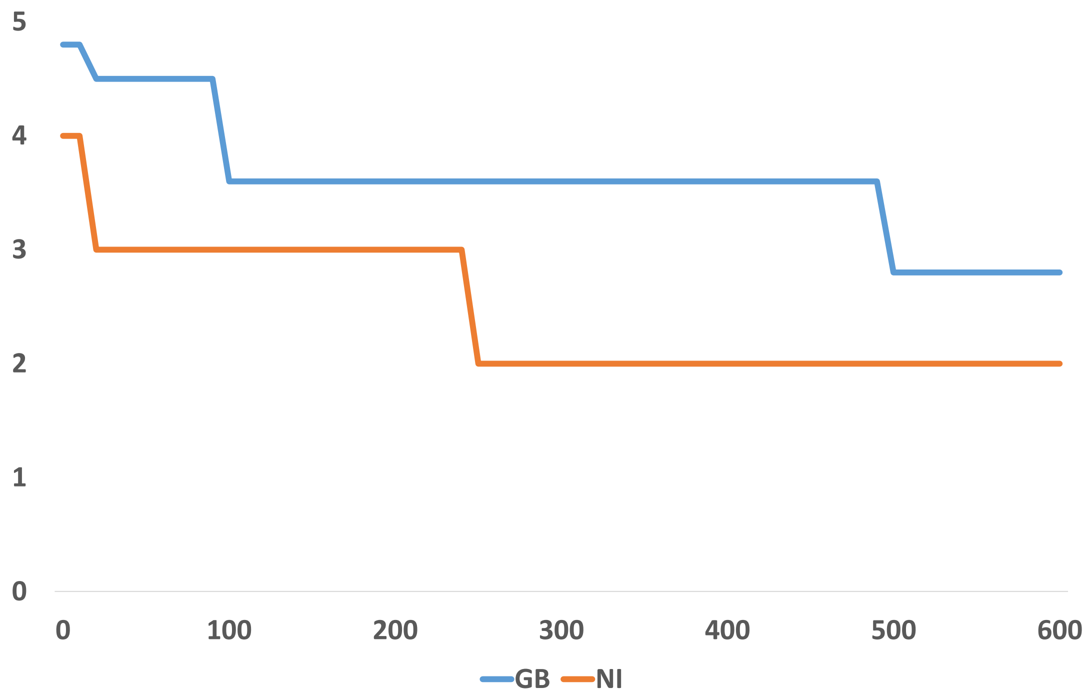
Figure 6.3: Comparison of GB and NI subsidy levels for AD up to 600kW



We note that DECC is planning to consult in early 2014 on AD subsidy levels, which might change this picture. At the time of writing, this consultation had not been published.

Finally we consider hydro. As Figure 6.4 shows, subsidy in NI is somewhat below that in GB, and the gap is particularly significant at the 250-500kW level.

Figure 6.4: Comparison of GB and NI subsidy levels for hydro up to 600kW



The major difference here is because there are *more* bands in NI than in GB. It suggests that it might be worth considering whether extending the NI 20-250kW band up to 500kW would be appropriate. However, we understand from discussions with stakeholders that there are only a limited number of sites at this scale in NI, given its geography, and that extending the band in this way is unlikely to lead to much if any further development. Even if a limited number of sites were found, there are also significant cost-effectiveness considerations in proposing a subsidy above that for PV. To achieve value for money, higher subsidy levels to hydro need to bring additional benefits beyond those that arise from subsidising PV. Since any potential new hydro sites at this size would have a negligible impact both on the achievement of NI's renewables target and on future deployment/ technology costs, it is difficult to see what these benefits might be. We therefore do not recommend extending the hydro band to 500kW.

We understand that there are more sites at the smaller end, particularly at sub-50kW, but that there may be issues here with connection requirements (such as the need for 3-phase connections above 20kW). It was suggested to us that the 0-20kW band in NI could be extended to 50kW. However, given the difficulties with connection requirements, it may make more sense to resolve these first, before increasing the number of ROCs.

6.3.2. Locational ROC banding

The effect of the differences in the level of congestion is to make renewables more expensive in some parts of the region than others. This then raises the question of whether the level of subsidy – that is, the number of ROCs – should reflect this, by varying depending on location.

We have briefly considered this option, but have rejected it. Our main reasons for doing so are practicality and efficiency.

Taking practicality first, the NIRO is already a relatively complex (if well understood) scheme. Adding an additional dimension of complexity by varying the number of ROCs by location would significantly add to this. The administrative costs could be very large, since the scheme administrator Ofgem does not currently provide for detailed geographic variation[43].

The second ground is efficiency. If we assume that the cost that renewables must pay to connect to the grid is a reasonable reflection[44] of the actual cost that would be incurred, then it can be seen as providing a clear economic signal about the value of renewables in a particular location. It is not clear what benefit there might be in DETI modifying its subsidy levels to blunt this signal. It might be argued that by reducing the likely uptake of renewables in certain regions of NI, we will make the renewables target more difficult to achieve, but the reality is that connecting small-scale renewables in certain regions will be

[43] Although it does allow the number of ROCs for a technology installed in NI to differ from those for a technology installed in GB.

[44] It should be noted that this assumption has been challenged by a number of developers that we spoke to.

very expensive, and the necessary subsidy to make this economic may be better spent in other ways.

6.3.3. Multi-installation tariffs

We have also considered the case for introducing multi-installation tariffs. In this, we have drawn heavily on the work done by DECC for the FIT Comprehensive Review[45]. In that document, dated May 2012, DECC noted that:

"*...[PB's report on PV costs][46] also showed that the differential in costs between single and multiple installations was narrower than previously estimated, with multiple installations costing around 90% of single installations*".

There is therefore a case for creating new multi-installation tariff bands for PV set at 90% of the rates for single installations. This should create some savings. However, there will be significant administration costs involved, and these need to be weighed against the benefits. We note here that the benefits would be from installations in the years 2015/16 and 2016/17 only, and only for those installations that took place under the NIRO (assuming that the FIT goes live in 2016). We also note that it would only be for one technology which historically has not been the major contributor to small-scale generation in NI, although its importance is growing. Finally, we note that this would create additional complexity in the NIRO.

Given this, on balance we judge that the administrative costs of introducing multi-installation tariff bands at this stage in the NIRO's lifecycle are unlikely to be justified by the limited potential benefits.

6.4. Summary

Based on the previous sections, we have identified three possible changes to the current banding levels, namely a drop in PV support, an increase in wind support and in support to hydro to reflect changes to technology costs. We have also identified one possible change to the bands, namely an extension of the wind band that currently runs to 250kW up to 500kW.

Other options have been considered and rejected. For example, we have rejected the options of locational banding on the grounds of complexity, and of increasing ROC levels to cover the increasing costs of grid connections (since this would not be cost-effective and would not overcome the issue of conditional connection agreements). We have also rejected changes to hydro banding on the grounds that they would have little impact and

[45] DECC, May 2012, *Feed In Tariffs Scheme: Government response to Consultation on Comprehensive Review Phase 2A: Solar PV cost control* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/43085/5386-government-response-to-consultation-on-comprehensi.pdf

[46] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/43083/5381-solar-pv-cost-update.pdf

are unlikely to be worth the administrative effort involved, or that they do not address underlying issues of grid connections. Finally, while we can see the longer-term case for multi-installation tariffs under a FIT regime, we do not consider that the potential savings from such tariffs for the final two years of the NIRO justify the administration costs that would be incurred. We recommend that DETI considers this issue again in the design of the FIT regime for NI.

In summary, the options we will analyse are those shown in Table 6.4 below.

Table 6.4: Options for analysis

Options	Cost of capital	Technology cost	ROCs	Deployment profile
PV change	Central – domestic 3%, commercial 7.5%	Medium	PV sub-250kW reduced to 1.6 ROCs from 4	Central
Sub-250kW wind	Central – domestic 3%, commercial 7.5%	Medium	Sub 250kW wind gets 4.5 ROCs, not 4	Central
Hydro	Central – domestic 3%, commercial 7.5%	Medium	Small scale hydro gets 6/ 4.7/ 2.3 ROCs	Central
Extend sub 250kW wind band to 500kW	Central – domestic 3%, commercial 7.5%	Medium	No changes to ROC levels	Central, except double deployment % for 50-500kW, reduce deployment for >5MW to ensure total still 100%
CENTRAL – all	Central – domestic 3%, commercial 7.5%	Medium	Combination of all changes above	Central, except double deployment % for 50-500kW, reduce deployment for >5MW to ensure total still 100%

In the next section, we will report the impact of each individual change and the overall potential impact. Impacts are reported on a relative basis, since the question facing DETI is whether changes to ROC bandings will lead to improved outcomes rather than necessarily the absolute level of costs and benefits. We will also conduct sensitivity analysis to check that our results are robust.

7. ANALYSIS OF IMPACTS

In this section we assess what the potential impacts of the options described in the previous section might be, based on our economic model. Potential impacts are assessed against the "do nothing" option of no change to the number of ROCs or to bandings. Our analysis looks at both the quantified impacts (such as the impact on consumer electricity bills) and more qualitative impacts such as those on the supply chain. As well as presenting a reasonable central view of impacts, we also perform sensitivity analysis in section 7.2 to test the robustness of our results.

7.1. Quantified impacts

The net estimated impact of each option is summarised in Table 7.1 below. Note that impacts are shown relative to the "do nothing" option. We show both overall net benefit and the impact on consumer bills.

Table 7.1: Key quantified impacts

Options	Net lifetime benefit/ (cost)	Impact on NI consumer bills (per household in 2020)
PV – 1.6 ROCs	0	-2.7p
Wind – 4.5 ROCs	0	1.9p
Hydro – additional ROCs	-£1.74m	0.5p
Extend sub-250kW wind band to 500kW	-£95.7m	13.0p
CENTRAL – all	-£101.3m	14.6p

The PV option involves a transfer from PV installers to consumers, since consumers would (under this option) pay less per unit of PV installed, but the number of units would – by assumption - not change. The other options all involve a net cost to consumers, and (except for the increase in ROCs for wind) a net cost to society as a whole. We explore the reasons for this below.

Taking PV first, our analysis strongly suggests that 4 ROCs is excessive for small-scale, since it gives a return for domestic installations of around 15% (real). Reducing subsidy to 1.6 ROCs should save around £384[47] per installation per year. Our analysis suggests that this would still give an expected return of nearly 9% (real)[48] in this case, and so while there might in reality be some slight reduction in deployment on more marginal sites as a result, the change does not make the technology uneconomic as a whole.

[47] Annual output of a 4kW installation is assumed to be 3.16 MWh. Assuming a ROC price of £46, the annual cost at 4 ROCs is £581.44, whereas at 1.6 ROCs it is £232.58.
[48] We note that DECC, in setting its FIT levels, targets a return of around 5%.

Turning now to wind, our analysis suggests that the increase of 0.5 ROCs is unnecessary. Wind at this size range is already economic at 4 ROCs and increasing subsidy by 0.5 ROCs is unlikely to materially change what is deployed. The current level of 4 ROCs still allows sufficiently high returns under the increased capex assumptions and the reduced availability of refurbished turbines. As noted earlier, even if it were concluded that ROC levels should be increased to deal with increasing connection costs in some areas, the increment required would be well above 0.5 ROCs, which is difficult to justify on cost-effectiveness grounds.

Extending the wind band to 500kW does though make a technology that was previously uneconomic (250-500kW wind) viable, and we assume that this increases the fraction of total wind deployment at this level. However, we assume that this means that this leads to a slight shift away from larger turbines. The latter tend to have a slightly higher load factor and so, while total capacity remains on track to hit the 2020 target, total *generation* reduces slightly. There is also a slight increase in consumer costs because each kW at the sub-500kW scale is receiving 4 ROCs, versus one at the larger scale, and so a shift to sub-500kW wind increases costs.

It could be argued that this change would lead to a shift to slightly larger turbines, which would tend to lead to a slight *increase* in total generation. However, this ignores the impact of connection costs, which appear to be pushing generators towards somewhat smaller turbines. In any event, the total impact of this band is likely to be small, if the GB experience is a guide. For all these reasons, we do not recommend making this change.

For hydro, there are two changes. First hydro at the 500-5,000kW level becomes economic. However, given that our understanding is that that there is negligible potential in NI at this size range, this makes no difference either to deployment or to costs. The 5-50kW level becomes more economic, and so we see some limited deployment at that level. However, it is difficult to justify this on cost-effectiveness grounds.

In summary, therefore, we recommend only changing the number of ROCs for PV below 250kW to 1.6.

Impact on consumer bills

The small impact on NI consumers' bills may be somewhat surprising. It is a reflection of two factors: the small size of the change being made, and the way that the costs of the NIRO are paid by UK consumers rather than solely by those in NI.

Taking the first factor, it should be remembered that the change proposed here amounts to a change to a single ROC band for a technology which (at the time of writing) contributed a little over 12MW. We can work out what this means in terms of ROCs per year, to better understand the low impact. ROCs are paid per MWh, so we need to work out MWh per year. We estimate that PV will have a load factor of around 9%, which gives a total annual output of 9,467 MWh. Each MWh receives 4 ROCs, at an estimated price of around £46 each, giving a total annual subsidy to this band of £1.742m. Our proposal reduces this to 1.6 ROCs per MWh, for a total annual saving of around £1.132m.

The second factor – that RO costs are paid by all UK consumers – means that costs are shared between the approximately 27m households in the UK. This gives a total annual average saving of 4p per household per year, and there is a further downward adjustment because of NI's lower target under the RO. There will be some upward adjustment to reflect higher levels of future deployment, but even if deployment of PV doubles, the cost to consumers of the change proposed here will be measured in pennies per household per year.

It should be emphasised that this does *not* mean that the change is not worthwhile. The total estimated benefit of the change is **over £1m per year, for a period of 20 years** (the tariff length of the NIRO). However, since that benefit is spread across the UK as a whole, the impact on individual annual consumer bills, and hence on fuel poverty, is negligible.

Impact on Levy Control Framework

The Levy Control Framework (LCF) places a limit on the spending from certain levy-funded schemes, of which the RO is one. Box 2.1 below gives more detail.

Box 7.1: The Levy Control Framework

The Levy Control Framework (LCF) was established in 2011 jointly by DECC and HM Treasury with the aim of managing the cost to consumers, investor confidence, and sustainability of levy-funded energy policies. These are policies that impose an obligation on energy suppliers and are not directly funded by government expenditure, instead being passed on to consumer bills. Renewable Obligations, Feed-in Tariff, and Contracts for Difference schemes all fall in the category of levy-funded schemes.

The LCF places a constraint on the aggregate amount levied on through these schemes. In 2011-12 the cap for spending under the LCF was £2 billion, set to rise to £7.6 billion by 2020. The following table shows the progression of the spending cap for levy-funded electricity policy from 2015.

2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
£4.30bn	£4.90bn	£5.60bn	£6.45bn	£7.00bn	£7.60bn

These upper limits do not include additional 20% headroom that is allowed for in the terms of the LCF. Should levy-funded spending exceed the upper limit, DECC and HM Treasury will agree on a plan to curtail spending. However, if the overspend is deemed temporary and within the agreed headroom, it is possible that no changes to policy be made.

Currently, policies for which levy-funded spending falls outside DECC's control due to the devolved nature of administering programs (as with the RO/NIRO) an allowance will be made.

We note that the annual impact of the changes we propose is of the order of £1m. It will therefore have a very small effect relative to the overall size of the LCF.

Impact on grid costs

This section looks at the impact on the costs of the grid of our proposed change.

We start by noting that our proposed changes focus on PV at the smaller scale. For this technology, the costs of connection are not a major issue in the same way as for example with wind. We therefore do not consider that our proposals – which do not change ROC levels for wind - have a significant net effect on grid costs in either direction. If anything, our proposed changes are likely to limit grid costs since they reduce the subsidy for PV and so will not increase deployment.

It is worth considering at this point what total grid costs will be. In particular, while generators do pay for a significant proportion of grid costs, they do not pay all of them under the current connection approach (see our earlier discussion in section 6.2.2). Under this approach, generators pay for[49]:

- connecting the generator to the distribution system;
- reinforcing the Distribution System are at the connection voltage level and one voltage level above; and
- in the case of a customer connecting at 33kV, reinforcing the Transmission System at 110k.

The important point for our purposes is that there may be costs arising as a result of the connection that generators do not pay; these would need to be paid by consumers in some way. NIE has made an estimate of £30m[50] for the consumer costs of the upgrades needed to 2017, and this figure is currently out for consultation.

There are a number of other possible impacts of our proposed changes: grid stability and administrative cost for ROC agents. We consider these in section 7.3 on wider impacts.

7.1.1. Summary of quantitative impacts

In summary, our proposed change has a very small financial impact on consumers and on the LCF. We do not expect any net impact on grid costs.

Like any modelling results, the figures above are sensitive to the underlying assumptions. We explore the degree of sensitivity in the next section.

[49] Source: Utility Regulator, 2011, *Next Steps Paper on Electricity Connection Policy for the Northern Ireland Distribution System* http://www.uregni.gov.uk/uploads/publications/Next_Steps_Paper_on_Electricity_Connections_to_the_NI_Dist_System_V_final.pdf

[50] Source: NIE submission to Competition Commission http://www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/131112_main_report.pdf , page 9-32

7.2. Sensitivity analysis

In this analysis we vary three of the key assumptions behind our modelling to test the robustness of our conclusions. Our focus is on whether the relative ranking of each option changes if the assumptions change.

The assumptions that we vary are:

- capital costs for each technology;
- discount rates; and
- deployment profiles.

We consider each in turn.

7.2.1. Capital costs

For our sensitivities on capital costs, we used high and low values based on our research and interviews with stakeholders. Detailed figures are given in Annex B. The range used is relatively wide. For example, for wind at the 50-500kW scale, we assume a capex cost of £2/kW (low case) and £5/kW (high case). Costs for AD are similarly wide: £3/kW (low case) and £7/kW (high case).

7.2.2. Discount rates

The values used for our sensitivity analysis on discount rates are shown in Table 7.2 below.

Table 7.2: Discount rate sensitivities

Sensitivity	Household discount rate	Commercial discount rate	Comments
High rate	4%	8%	The top end of the ranges we considered
Low rate	0%	5%	The lower end of the ranges that we considered
Central case	3%	7.5%	Shown for comparison purposes only

In short, we have used the upper and lower end of the ranges identified in our analysis as the high and low sensitivities respectively. Note that to be conservative our "central" case is actually closer to the high end of the range.

7.2.3. Deployment profiles

As discussed in section 4.4, our model takes as input an assumption about how total deployment for a technology is split by size band. Our central case for each technology is shown in Table 7.3 below.

Table 7.3: Central case deployment scenarios

Size band	Capacity (kW)	Wind	PV	AD	Hydro
Domestic	**<5**	-	40.0%	-	1.0%
Small	**5-50**	0.6%	60.0%	-	75.0%
Medium 1	**50-500**	5.7%	-	100.0%	24.0%
Medium 2	**500-5,000**	3.2%	-	-	-
Other	**>5,000**	90.4%	-	-	-
TOTAL		***100%***	***100%***	***100%***	***100%***

We have also considered two sensitivities where the profiles are somewhat different. The first is shown in Table 7.4 below.

Table 7.4: Deployment scenarios – sensitivity 1

Size band	Capacity (kW)	Wind	PV	AD	Hydro
Domestic	**<5**	-	34.2%	-	1.0%
Small	**5-50**	-	65.8%	-	71.0%
Medium 1	**50-500**	2.0%	-	100.0%	28.0%
Medium 2	**500-5,000**	4.0%	-	-	-
Other	**>5,000**	94%	-	-	-
TOTAL		***100%***	***100%***	***100%***	***100%***

This sensitivity assumes that deployment is on average at smaller scales than our central case. By contrast, our second sensitivity assumes that deployment is on average at a slightly larger scale. This is shown in Table 7.5 below.

Table 7.5: Deployment scenarios – sensitivity 2

Size band	Capacity (kW)	Wind	PV	AD	Hydro
Domestic	**<5**	-	45.0%	-	2.0%
Small	**5-50**	1.0%	50.0%	-	80.0%
Medium 1	**50-500**	6.0%	-	100.0%	18.0%
Medium 2	**500-5,000**	3.0%	-	-	-
Other	**>5,000**	90.0%	5.0%	-	-
TOTAL		***100%***	***100%***	***100%***	***100%***

The impact of these sensitivities should not be over-stated. In particular, for the technology that provides the greatest proportion of installed capacity, namely wind, in all cases the vast majority of installed capacity is at the >5MW level. Since the deployment profiles relate only to the two years 2015/16 and 2016/17, we do not consider that more radical departures from current deployment profiles are reasonable.

7.2.4. Sensitivities considered

In determining the sensitivities to run, we have taken the “high” and “low” value for each assumption, and test the impact of each one in isolation. We also look at two combinations of assumptions – one designed to maximise small-scale deployment and one designed to minimise it, to get a sense of the upper and lower reasonable limits. These sensitivities are shown in Table 7.6 below.

Table 7.6: List of sensitivities analysed

Case	Change from central case – PV change
Low discount	Domestic discount rate 0%, commercial 5%
High discount	Domestic discount rate 4%, commercial 8%
Low cost	Use “low” technology cost figures, all technologies
High cost	Use “high” technology cost figures, all technologies
Smaller-scale deployment	Use “sensitivity 2” deployment profile
Larger-scale deployment	Use “sensitivity 1” deployment profile
Maximise small-scale deployment	Domestic discount rate 0%, commercial 5% Use “low” technology cost figures, all technologies Use “sensitivity 2” deployment profile
Minimise small-scale deployment	Domestic discount rate 4%, commercial 8% Use “high” technology cost figures, all technologies Use “sensitivity 1” deployment profile

For each sensitivity, we changed the assumptions set out in the table above, and then compared the impact of “do nothing” with that set of assumptions, versus the impact of changing the subsidy for PV to 1.6 ROCs. In the next sub-section, we look at the results for each sensitivity.

7.2.5. Results

The results of each sensitivity around our recommended option of reducing ROCS for PV to 1.6 are shown in Table 7.7 below.. The central case results are shown for comparison purposes.

Table 7.7: Sensitivities analysed - results

Case	Net lifetime benefit/ (cost)	Impact on NI consumer bills (per household in 2020)
CENTRAL CASE (PV to 1.6 ROCs)	0	-2.7p
Low discount	£ 116.8m	-2.4p
High discount	-£ 6.3m	-3.2p
Low cost	£ 95.2m	-2.4p
High cost	£ 30.7m	-17.8p
Smaller-scale deployment	-£ 6.1m	-2.3p
Larger-scale deployment	£ 64.0m	-10.7p
Maximise small-scale deployment	£ 198.8m	-0.4p
Minimise small-scale deployment	£ 22.9m	-13.9p

Based on this, we conclude that our results are robust. Most of the sensitivities shown above make no difference to the impact of the proposed change, in terms of NI consumer bills. This is as expected since PV is broadly economically viable across the range of our assumptions. Where there is a difference, it is very small - less than a penny per household per year.

Crucially, in all the sensitivities we considered, the net impact of our proposed change is to reduce consumer bills. This is a more helpful measure than net benefit, since reducing subsidy for small-scale PV reduces payments to businesses and households installing PV, but also reduces payments from consumers by the same amount. The net benefit to NI is therefore zero[51].

7.3. Qualitative analysis of impacts

In this section we assess the non-quantified impacts of each option. Again, these assessments are done relative to the "do nothing" option. We analyse the following impacts:

- impact on the SEM, grid and planning; and
- economic benefits to NI and the renewables supply chain.

While these impacts are not quantified, it is clear that the size of each impact will be broadly proportional to the level of renewables deployment. Since our proposed change is unlikely to make a drastic change to deployment (and if there is a change it will be a decrease) the impacts are likely to be minimal. We therefore explore each one relatively briefly.

[51] This ignores the fact that some of the installers might be based outside NI, and so payments to them are a net cost to NI. However, since our proposed option *reduces* payments to installers, it should if anything have a net benefit to NI.

Impact on the SEM, grid and planning

Our proposed change is focused on small-scale PV. Potential grid issues include system stability and the impact of reduced demand on distribution charges and fuel poverty.

Taking system stability first, the view has been expressed to us that (partly because these PV installations are owned and managed by those not expert in the electricity system) there might be issues with maintaining compliance with the network code in all cases, and that this might cause issues for the system operator. It has also been suggested that – since the distribution network was designed to facilitate the flow of power from large generators to consumers – the *export* of power from consumers might cause grid issues.

System charges were also mentioned as a possible issue. Where a household or business installs small-scale PV, it will in future purchase less power from the grid. This means that the household or business will be making less of a contribution to the costs of maintaining the grid, since these costs are included in the cost of power. This could push up the price of power for others, and this could in turn have knock-on impacts on fuel poverty.

There is also the issue of the administrative costs of processing applications to ROC agents. These will be proportional to deployment, and we understand that concern has already been expressed about potential future costs.

These issues have been articulated elsewhere, and we do not dwell on them here. We do note that our proposed changes would not *increase* the level of small-scale deployment, and so would be unlikely to worsen the impact of these issues.

Economic benefits and renewables supply chain

Increasing or decreasing the deployment of renewables in NI is likely to lead to a change in patterns of employment. These impacts should not be over-stated, since much or all of the equipment installed is imported. However, there will be a need for individuals in NI skilled in the installation, maintenance and repair of renewables. If future deployment increases significantly, there could be a reduced need for individuals skilled in installing alternative technologies. However, since our proposed changes are not expected to have a noticeable effect on renewables deployment, any such changes to requirements are likely to be minimal.

Consistency with subsidy levels in GB

Our analysis of suitable ROC bands is based on technology costs. Another consideration for setting ROC levels is the consistency of policies with the larger bands, and also with renewable support policies Great Britain. These suggest a higher subsidy level than the ROC levels that we recommend based solely on technology costs.

7.3.1. Summary

In short, we do not expect major wider benefits or costs from our proposed change, essentially because we expect it to have limited impact on total deployed renewables. This is not unexpected since the changes only apply to one technology, and only cover a period of two years (2015/16 and 2016/17).

7.4. Summary of impacts

We now bring together the quantified and wider impacts analysis from above to present the overall picture.

Our analysis suggests that our proposed change to the NIRO would have a very limited impact. This is as expected since we do not expect it to change deployment levels drastically, because it only covers a period of two years, and because we only propose a change to one NIRO band. However, we still consider that the change is worthwhile. There are benefits in terms of savings from reducing what appears to be a relatively high level of subsidy for small-scale PV to levels more in line with what is required to support deployment. The administrative costs should be relatively small since the change only involves modifying the ROC level for one band. Wider impacts should be minimal and in any case reducing the level of support should serve to reduce the risk of very high levels of PV deployment which could have a number of undesirable impacts.

8. CONCLUSIONS AND RECOMMENDATIONS

In our report, we have considered a number of potential changes to the NIRO, both in terms of the number of ROCs for each band and changes to the bands themselves, and assessed their costs and benefits, both overall and to average consumer bills. We have also sought to identify some of the wider but related issues such as the reasons for increasing connection costs.

We have concluded that the most appropriate change would be a significant reduction in the number of ROCs for PV under 250kW, because of drastic drops in the cost of the technology over the last few years. As far as other technologies are concerned, they have shown either no change in costs, or an increase, but it is difficult to justify increasing subsidy for them on cost-effectiveness grounds. Even with reduced number of ROCs for PV and with small increases of costs for other technologies, the expected returns remain sufficiently high for investment.

Our recommendations are based on technology cost and on consistency with support for the larger bands in NI. Another consideration is consistency with policies in GB where the current FITs tariffs suggest higher subsidy levels.

It is also difficult to justify making a number of other possible changes to the NIRO, such as varying ROC bands or introducing a band for multi-site PV installations. The essential point here is that any changes would only affect small-scale renewables deployed in NI in 2015-16 and 2016-17. The potential benefits from changes affecting only these two years are low, and so unlikely to outweigh the corresponding administration costs and the costs of the additional complexity that the changes would bring.

One reason for the benefits being low is that changes to support levels for small-scale renewables have relatively small impacts on NI consumers. First, such renewables make a relatively small contribution both to total renewables and to overall electricity generation. In aggregate, all small-scale renewables installed in NI provide 70.6MW.[52] This is around 12%[53] of total renewables deployment in NI. Second, the cost of support under the NIRO is spread across all UK consumers, since NIROCs are tradable with ROCs from GB. NI renewables generation represented around 2.9% of UK-wide renewables in 2013[54], so any changes to NI costs will only have a limited impact on total UK costs and so total RO costs to be borne by NI consumers.

Finally, it should be pointed out that some of the conclusions of this report, in terms of the relative size of the costs and benefits of particular options, would be different if the NIRO were remaining open past 2017. We therefore recommend that DETI consider these issues separately in its design of the FIT.

[52] Source: Ofgem ROC register, accessed 17 January 2014

[53] Ignoring the Kilroot station, which is not 100% renewable

[54] Source: Ofgem

Annex A. DATA SOURCES

Table A.1: Sources

Assumption	New value	Source
Irish CPI	Irish CPI from March '06 – Oct '13 (slight revisions in '06-'10)	Central Statistics Office (CSO)
€ / £ exchange rate	1.19 (ECB Monthly average, Nov 2013)	European Central Bank (ECB)
ETS price €/tonne	4.82 (yearly average spot 2013)	Bloomberg
GVA per employee per annum	£37,424 (2011)	Office of National Statistics (ONS)
Domestic export tariff (all scenarios) £/MWh	55.90	Power NI
Export tariff (all scenarios) for 50-500 MWh in £/MWh	Now paid market price – i.e. projected SEM wholesale market price (a CEPA assumption not updated). See table B.2	Power NI
Electricity use assumptions (GB)	Commercial & Industrial: 63% Domestic:37%	DUKES 2013
Businesses (Northern Ireland)	67, 640 (2012)	ONS
Price of Carbon Emissions	See Annex B	DECC Updated Carbon Prices for Modelling (2013)
GB electricity price projections	See Annex B	DECC 2013 Updated Emissions and Energy Projections
NI total electricity supplier demand	See Annex B	SONI / EirGrid All-Island Generation Capacity Statement 2013
GB total electricity supplier demand	See Annex B	DECC 2013 Updated Emissions and Energy Projections
NI households forecast	See Annex B	Northern Ireland Statistics and Research Agency(NISRA)
Fuel mix of displaced output	See Annex B	SEAI Energy Forecast for Ireland 2011-2020
Subsidy levels in comparison countries	As described in Section 5.3	• RES LEGAL database (http://www.res-legal.eu/search-by-country/)

Assumption	New value	Source
		• Ofgem Feed-In Tariff tables
Wind costs and markets	See Annex B	• Stakeholders listed below • Renewable UK, Small & Medium Wind UK Market Report 2013 • IEA, Wind Annual Report 2012 • NREL, Past & Future Cost of Wind Energy (IEA Wind Task 26), 2012 • PB for DECC, Update of non-PV data for Feed-In Tariff, June 2012
Solar PV costs and markets	See Annex B	• Stakeholders listed below • IEA Photovoltaic Power Systems Programme, National Survey Reports 2012 • PV Magazine, Nov 2013[55] and Dec 2013[56] • Solar Power Portal, Sept 2013[57] • Danish Solar Association[58] • Van Sark et al, "Grid Parity Reached in the Netherlands for Consumers", 2012 27th European Photovoltaic Solar Energy Conference and Exhibition • GTM Research, PV Technology & Cost Outlook 2013-2017[59]

55 http://www.pv-magazine.com/investors/pv-system-prices/#axzz2pcbqiLpi

56 http://www.pv-magazine.com/news/details/beitrag/global-pv-installations-to-reach-45-gw-in-2014--say-ihs_100013773/#axzz2pcbqiLpi

57 http://www.solarpowerportal.co.uk/guest_blog/the_end_of_ever_dropping_residential_solar_prices

58 http://www.solcelleforening.dk/fakta/publikationer-og-links/fau-rapporter. Data from 2011 adjusted to 2013 values using profile from PV Magazine cost profile (reference 49)

Assumption	New value	Source
AD costs & markets	See Annex B	• Stakeholders listed below • SEIA, The Role of Anaerobic Digestion in Irish Agriculture, 2011[60] • IRENA, Renewable Energy Technologies Cost Analysis - biomass, 2012 • Jacobsen et al, "The Economics of Biogas in Denmark', 2012 • PB for DECC, Update of non-PV data for Feed-In Tariff, June 2012
Hydro costs & markets	See Annex B	• Stakeholders listed below • European Small Hydropower Association publications, www.esha.be • World Energy Outlook 2013 • IRENA, Renewable Energy Technologies Cost Analysis - hydropower, 2012 • ECOFYS, Financing Renewable Energy in the European Energy Market, 2011 • PB for DECC, Update of non-PV data for Feed-In Tariff, June 2012

Other cost data has been sourced from the stakeholders listed below, PB project experience and from confidential sources.

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[59] Reported in http://www.pv-tech.org/news/pv_module_costs_to_fall_to_36c_per_watt_by_2017_gtm_research

[60] http://www.teagasc.ie/publications/2011/828/Tom_Knitter.pdf

Stakeholders contacted

The table below lists the stakeholders that we have spoken to as part of this project. We are very grateful to everyone who offered their time. Note that stakeholders gave their comments on an anonymous basis and so we have not attributed specific comments or pieces of information to particular stakeholders.

Table A.2: Stakeholders contacted

Organisation
A GB network company
Action Renewables
AIB
Danske Bank
Hydro NI
KPMG
NI Renewables Industry Group (NIRIG)
NIE
PDB Bio
Planet Solar
POB Solar
Power NI
Simple Power
Utility Regulator

Annex B. Detailed data tables

This annex presents supplementary tables to provide more detail.

Table B.1: Export tariff – 50-500 MWh Generation (£/MWh)

Year	Old	SEM Price Assumption
2012	51.67	67.88382
2013	51.67	68.53443
2014	51.67	69.27807
2015	51.67	69.76605
2016	51.67	69.37601
2017	51.67	68.69842
2018	51.67	69.10088
2019	51.67	70.10197
2020	51.67	71.01197
2021	51.67	73.83042
2022	51.67	76.74499
2023	51.67	79.60597
2024	51.67	82.49903
2025	51.67	85.39252
2026	51.67	88.46116
2027	51.67	92.03489
2028	51.67	95.81417
2029	51.67	98.90606
2030	51.67	102.303

Table B.2: DECC Carbon Price Projections - £/tonne CO_2

Year	Old			New		
	Central	Low	High	Central	Low	High
2011	18.63979	13	18.63979			
2012	18.63979	13	18.63979			
2013	18.63979	13	18.63979	3.49	0	15.57
2014	18.63979	13	18.63979	3.59	0	16.73
2015	20.76937	13	20.76937	3.67	0	18.01
2016	22.89896	13	22.89896	3.79	0	19.39
2017	25.02854	13	25.02854	3.92	0	20.89

Year	Old			New		
	Central	Low	High	Central	Low	High
2018	27.15813	13	27.15813	4.22	0	22.49
2019	29.28771	14	29.28771	4.53	0	24.19
2020	30.95663	14	30.95663	4.87	0	25.98
2021	30.95663	14	30.95663	4.99	0.12	27.2
2022	30.95663	14	36.56	5.12	0.25	27.89
2023	30.95663	16	46.17	5.25	0.38	28.6
2024	35.39	18	55.79	5.38	0.51	29.32
2025	42.1	20	65.4	5.52	0.65	30.07
2026	48.81	23	75.02	5.66	0.79	30.83
2027	55.52	25	84.63	5.8	0.93	31.61
2028	62.23	27	94.25	5.95	1.08	32.41
2029	68.94	29	103.86	6.1	1.23	33.23
2030	75.65	31	113.48	6.25	1.39	34.07

Table B.3: GB Electricity Wholesale Price Forecast (£/MWh)

Year	Old	New
2012	50.45114	44.17607
2013	56.60265	47.32715
2014	64.67734	52.42819
2015	67.51479	58.72655
2016	71.32501	61.07697
2017	70.09176	61.66298
2018	67.99358	62.88057
2019	67.90903	62.46545
2020	66.82063	63.04434

Table B.4:NI Total Electricity Supplier Demand (TWh)

Year	Old	New
2012	9.10	9.037
2013	9.24	9.028
2014	9.38	9.103
2015	9.52	9.259
2016	9.66	9.418

Year	Old	New
2017	9.81	9.575
2018	9.95	9.731
2019	10.10	9.886
2020	10.25	10.043
2021	10.25	10.201
2022	10.25	10.361
2023	10.25	10.254
2024	10.25	10.254
2025	10.25	10.254

Table B.5:GB Total Electricity Supplier Demand (TWh)

Year	Old	New
2012	363.93	317.5485
2013	365.66	314.0159
2014	368.37	309.9346
2015	370.32	305.6062
2016	370.78	302.6342
2017	371.32	300.315
2018	372.37	299.9267
2019	374.10	299.0821
2020	375.52	299.6659
2021	377.68	303.6703
2022	379.95	306.615
2023	382.56	311.0541
2024	385.14	315.777
2025	385.99	320.0077
2026		325.6875
2027		331.7606
2028		339.3551
2029		346.4196
2030		353.6189

Table B.6:NI Household Forecast (Number of Households)

Year	Old	New

Year	Old	New
2012	724,000	724,000
2013	732,800	732,800
2014	741,200	741,200
2015	749,200	749,200
2016	756,900	756,900
2017	764,500	764,500
2018	772,000	772,000
2019	779,300	779,300
2020	786,800	786,800
2021	786,800	794,400
2022	786,800	802,300
2023	786,800	810,400
2024		818,600
2025		826,500
2026		834,100
2027		841,500
2028		848,400
2029		855,200
2030		861,600
2031		867,900
2032		874,200
2033		880,400

Table B.7:Fuel Mix of Displaced Output Scenario 1 (SEAI All-Island forecast)

Year	Coal		Natural Gas		Oil		Peat	
	Old	New	Old	New	Old	New	Old	New
2011	23%	17%	77%	72%	-	2%	-	9%
2012	23%	18%	77%	72%	-	2%	-	9%
2013	23%	18%	77%	72%	-	2%	-	9%
2014	23%	18%	77%	72%	-	1%	-	9%
2015	24%	19%	76%	72%	-	1%	-	9%
2016	24%	19%	76%	72%	-	0%	-	9%
2017	24%	19%	76%	71%	-	0%	-	9%

Year	Coal		Natural Gas		Oil		Peat	
	Old	New	Old	New	Old	New	Old	New
2018	24%	20%	76%	71%	-	0%	-	9%
2019	24%	20%	76%	71%	-	0%	-	9%
2020	25%	21%	75%	70%	-	0%	-	9%
2021	25%	21%	75%	70%	-	0%	-	9%
2022	25%	21%	75%	70%	-	0%	-	9%

Table B.9: Emissions factors (tonnes CO2/MWh)

	Old		New	
	DECC	CER	DECC	IEA
Coal	0.87	0.973029	0.91	0.869
Natural Gas	0.37	0.577029	0.39	0.398
Oil	0.63	0.779143	0.59	0.703
Peat	0.63	1.090286	0.59	0.869

Table B.10: Current Installed Capacity (MW)

	Size	Old	New
Onshore wind	0-5kW	0.3908	0.3472
	5-50kW	2.87	2.8015
	50-500kW	9.46	13.9298
	500kW-5MW	36.25	39.1448
	5MW-10MW	56.78	50.4555
	>10MW	361.24	395.0297
AD	0-5kW	-	-
	5-50kW	-	0.0167
	50-500kW	0.563	1.0523
	500kW-5MW	1.44	2.2840
	5MW-10MW	-	-
	>10MW	-	-
Hydro	0-5kW	0.00	0.0072
	5-50kW	0.29	0.7230
	50-500kW	2.25	4.6708
	500kW-5MW	1.45	3.1369

	Size	Old	New
	5MW-10MW	-	-
	>10MW	-	-
PV	0-5kW	1.19	7.5383
	5-50kW	0.81	9.9857
	50-500kW	-	-
	500kW-5MW	-	-
	5MW-10MW	-	-
	>10MW	-	-

Table B.11: Baseline Banding assumptions (ROCs/MWh)

	Size	Old			New		
		2014	2015	2016	2014	2015	2016
Onshore wind	0-5kW	4	4	4	4	4	4
	5-50kW	4	4	4	4	4	4
	50-500kW	4	4	4	4	4	4
	500kW-5MW	1	1	1	1	1	1
	5MW-10MW	1	1	1	0.9	0.9	0.9
	>10MW	1	1	1	0.9	0.9	0.9
AD	0-5kW	0	0	0	4	4	4
	5-50kW	3	3	3	4	4	4
	50-500kW	3	3	3	4	4	4
	500kW-5MW	3	3	3	3	3	3
	5MW-10MW	3	3	3	2	1.9	1.8
	>10MW	3	3	3	2	1.9	1.8
Hydro	0-5kW	4	4	4	4	4	4
	5-50kW	3	3	3	3	3	3
	50-500kW	2	2	2	2	2	2
	500kW-5MW	1	1	1	1	1	1
	5MW-10MW	1	1	1	0.7	0.7	0.7

	Size	Old			New		
		2014	2015	2016	2014	2015	2016
	>10MW	1	1	1	0.7	0.7	0.7
PV	0-5kW	4	4	4	4	4	4
	5-50kW	4	4	4	4	4	4
	50-500kW	2	2	2	1.6	1.5	1.4
	500kW-5MW	1.6	1.5	1.4	1.6	1.5	1.4
	5MW-10MW	1.6	1.5	1.4	1.6	1.5	1.4
	>10MW	1.6	1.5	1.4	1.6	1.5	1.4

Table B.12: Generation Deployment Scenario (MW)

Technology	Old (SONi 2022 forecast)	New (based on SONi 2020 forecast)
Wind Onshore	1,228.0	1,044.8
Wind Offshore	600.0	184.1
AD	32.0	21.7
Biomass	61.0	46.3
Tidal	201.0	148.4
Other fuelled	42.0	28.4
Hydro	4.0	3.9
PV	6.0	49.4

Table B.13: Capex (£/kW)

		Old (2010 in 2013 prices)			New (2013 in 2013 prices)		
		High	Central	Low	High	Central	Low
Onshore wind	0-5kW	7809	5206	2603	8000	6500	5000
	5-50kW	5206	3124	1666	8000	6500	5000
	50-500kW	3124	2603	1458	5000	3100	2000
	500kW-5MW	1822	1562	1458	3000	2200	1400
AD	0-5kW	-	-	-	7000	5000	3000
	5-50kW	12495	10413	7289	7000	5000	3000
	50-500kW	6039	4894	3644	7000	4750	3000
	500kW-5MW	3124	2603	2083	6000	4500	3000

		Old (2010 in 2013 prices)			New (2013 in 2013 prices)		
		High	Central	Low	High	Central	Low
Hydro	0-5kW	10413	5206	3124	17000	10000	7000
	5-50kW	10413	4165	3124	13500	8400	5500
	50-500kW	3332	3124	2863	10000	6800	4000
	500kW-5MW	3124	2603	2083	8000	3500	2000
PV	0-5kW	7809	5206	4165	1960	1640	1200
	5-50kW	6248	4477	3644	1400	1243	1077
	50-500kW	6248	4165	3384	1230	1060	980
	500kW-5MW	4165	3644	3124	1200	1000	850

Table B.14: Opex (£/kW/year)

		Old (2010 in 2013 prices)			New (2013 in 2013 prices)		
		High	Central	Low	High	Central	Low
Onshore wind	0-5kW	260	208	104	83	60	50
	5-50kW	83	57	31	83	60	50
	50-500kW	78	62	26	75	60	33
	500kW-5MW	46	36	26	35	30	25
AD	0-5kW	0	0	0	1000	800	600
	5-50kW	1041	677	312	1000	800	600
	50-500kW	1458	1041	521	1000	800	600
	500kW-5MW	771	573	385	1000	700	500
Hydro	0-5kW	312	182	104	300	160	150
	5-50kW	312	182	104	300	180	150
	50-500kW	208	156	62	300	200	150
	500kW-5MW	78	52	26	200	100	65
PV	0-5kW	115	78	46	36	27	22
	5-50kW	25	23	18	32	24	19
	50-500kW	23	21	19	29	23	17
	500kW-5MW	23	21	19	29	23	17

Table B.15: Capex learning rate (as a % of base year capex)

		Old			New		
		2012	2017	2021	2014	2015	2016
Onshore wind	0-5kW	100%	64%	55%	102%	104%	106%
	5-50kW	100%	73%	70%	102%	104%	106%
	50-500kW	100%	81%	73%	102%	104%	106%
	500kW-5MW	100%	85%	76%	102%	104%	106%
AD	0-5kW	100%	100%	100%	100%	100%	100%
	5-50kW	100%	95%	90%	100%	100%	100%
	50-500kW	100%	95%	90%	100%	100%	100%
	500kW-5MW	100%	95%	90%	100%	100%	100%
Hydro	0-5kW	100%	100%	100%	103%	105%	108%
	5-50kW	100%	100%	100%	103%	105%	108%
	50-500kW	100%	100%	100%	103%	105%	108%
	500kW-5MW	100%	100%	100%	103%	105%	108%
PV	0-5kW	100%	70%	60%	95%	93%	91%
	5-50kW	100%	60%	50%	95%	93%	91%
	50-500kW	100%	60%	50%	95%	93%	91%
	500kW-5MW	100%	60%	50%	95%	93%	91%

Table B.16: Opex learning rate (as a % of base year opex)

		Old			New		
		2012	2017	2021	2014	2015	2016
Onshore wind	0-5kW	100%	100%	100%	100%	100%	100%
	5-50kW	100%	100%	100%	100%	100%	100%
	50-500kW	100%	100%	100%	100%	100%	100%
	500kW-5MW	100%	100%	100%	100%	100%	100%
AD	0-5kW	100%	100%	100%	103%	105%	108%
	5-50kW	100%	100%	100%	103%	105%	108%
	50-500kW	100%	100%	100%	103%	105%	108%
	500kW-5MW	100%	100%	100%	103%	105%	108%

		Old			New		
		2012	2017	2021	2014	2015	2016
Hydro	0-5kW	100%	100%	100%	100%	100%	100%
	5-50kW	100%	100%	100%	100%	100%	100%
	50-500kW	100%	100%	100%	100%	100%	100%
	500kW-5MW	100%	100%	100%	100%	100%	100%
PV	0-5kW	100%	100%	100%	100%	100%	100%
	5-50kW	100%	100%	100%	100%	100%	100%
	50-500kW	100%	100%	100%	100%	100%	100%
	500kW-5MW	100%	100%	100%	100%	100%	100%

Table B.17: Generation mix (central case)

Technology	Size	Old	New	Sensitivity 1	Sensitivity 2
Onshore wind	0-5kW	-	-	0.0%	0.0%
	5-50kW	5.0%	0.6%	0.0%	1.0%
	50-500kW	10.0%	5.7%	2.0%	6.0%
	500kW-5MW	15.0%	3.2%	4.0%	3.0%
	>5MW	70.0%	90%	94%	90%
AD	0-5kW	-	-	-	-
	5-50kW	-	-	-	-
	50-500kW	100.0%	100.0%	100.0%	100.0%
	500kW-5MW	-	-	-	-
	>5MW	-	-	0.0%	0.0%
Hydro	0-5kW	1.0%	1.0%	1.0%	2.0%
	5-50kW	71.0%	75.0%	71.0%	80.0%
	50-500kW	28.0%	24.0%	28.0%	18.0%
	500kW-5MW	-	-	-	-
	>5MW	-	-	0.0%	0.0%
PV	0-5kW	1.0%	40.0%	34.2%	45.0%

Technology	Size	Old	New	Sensitivity 1	Sensitivity 2
	5-50kW	40.0%	60.0%	65.8%	50.0%
	50-500kW	59.0%	-	-	-
	500kW-5MW	-	-	-	5.0%
	>5MW	-	-	0.0%	0.0%

Annex C. DESCRIPTION OF PROJECT MODEL

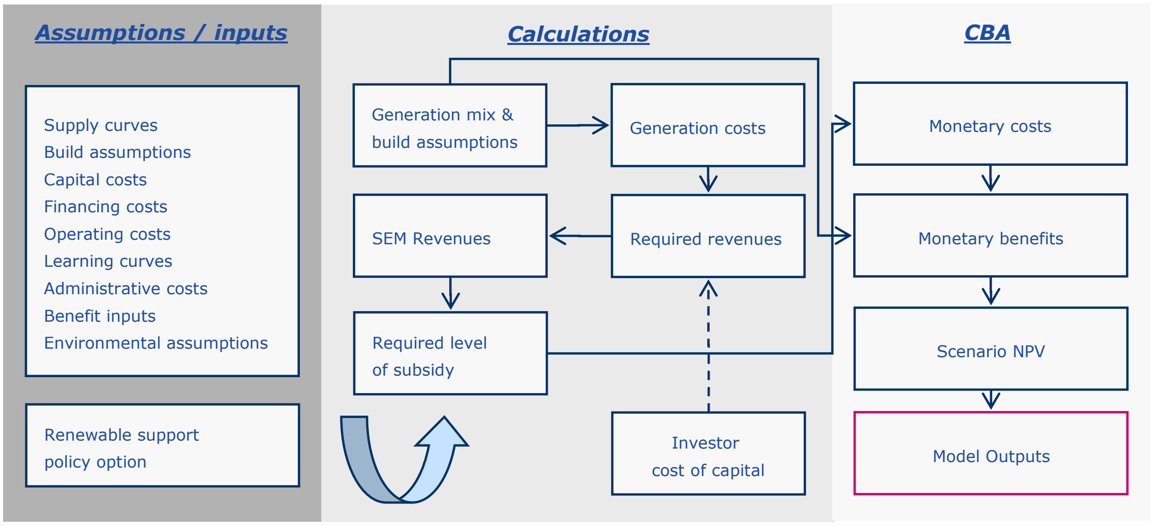
In this section we describe the modelling framework which has been developed to simulate the impacts of alternative support mechanisms. We begin by providing a high level structural overview of the bespoke model which CEPA/PB has developed for this project, before going on to discuss the modelling approach for different support options, key assumptions and the outputs produced by the model.

Overview of model structure

The overall objective of the model is to allow us to assess how alternative approaches to supporting renewable generation in NI compare to the costs, benefits and levels of deployment delivered by the existing support mechanism. These scenarios are based around the interaction of a number of policy support options – the NIRO (in its current form), future amendments to the NIRO and the UK-wide Renewables Obligation, potential FIT structures and Capital Grant schemes.

The structure of the modelling framework is summarised at a high-level in Figure C.1.

Figure C.1: CEPA / PB modelling approach



Source: CEPA / PB

The figure shows how a number of inputs and assumptions are combined through a series of calculations to produce a series of model outputs, in terms of patterns of renewables deployment, together with the costs and benefits associated with these levels of deployment.

The model has been designed to provide the user with freedom to model various combinations and permutations of support option. The user is able to specify all aspects of subsidy design; including the type of support scheme – be that a support based on a certificate style scheme, a FIT or a capital grant, the parameters of that scheme (i.e. the levels of FIT or banding for different technologies) and to vary all input assumptions, including wholesale prices and costs. As such the model is a tool which enables users to model options beyond those specifically specified in the study's terms of reference.

For a given potential renewable generation resource potential, the model calculates the proportion of projects that are viable, based on the expected costs of different technology types/scales (which vary over time) and the revenues those projects would expect to receive via the Single Electricity Market (SEM), other sources of revenues and the selected support mechanism). This derives a projected renewable generation supply curve in NI for each year, which is then assessed against NI's projected resource potential. Where applicable, in each year, expected revenue streams under the NIRO (i.e. the expected ROC price) are assessed based on simulated renewables supply curves in NI.

The model then calculates the costs and benefits of the selected support mechanism and presents a range of outputs demonstrating expected costs and benefits.

The modelling framework assumes:

- If renewable generation technologies are viable (based on expected cost and revenue streams), subject to annual build constraints, renewable generation is deployed.
- Although a feasible build profile to 2020 based on discussions with DETI and NIAUR is adopted in the modelling framework (see Section 3.4 below) the analysis assumes no planning delays or constraints.

Model outputs

The outputs generated by the model are grouped as follows:

- **Deployment** – An assessment of the level of RES-generation deployment, specifically whether NI's 2020 target is met.
- **Costs and benefits** – A comparison of the costs and benefits of alternative FIT options, including the resource cost, any costs of over subsidy, emission savings and other economic benefits.
- **Cost to NI consumers and NI budget** – We also provide an analysis of the likely costs to consumers and government of the support mechanism, including the cost per unit of electricity consumption and the cost per unit of renewable generated under a scheme.

Costs and benefits

Specific cost and benefit outputs presented from the modelling analysis include:

- **Resource cost –** equals total expenditure comprising capital and operating costs on generation plant under a given policy scenario.
- **Production subsidy cost –** equal to the total cost of the subsidy provided to renewable generators.
- **Deadweight costs – "windfall gains"** – defined as the level of subsidy cost over and above that which would strictly be required to make investment viable.
- **Annual subsidy cost to consumers –** this is the total annual subsidy cost to NI electricity suppliers which is assumed to be passed on to consumers.
- **Cumulative cost to consumers –** this demonstrates the cumulative cost to consumers to a specified date (for example, over the operating life of projects commissioned by 2020, or the cumulative cost to consumers to 2020).
- **Cost to the public purse in NI –** which is calculated as the value of any capital grants provided as incentives for investment in renewable generation[61].
- **Value of emissions savings –** which shows, based on an assumed fuel mix within the SEM, the benefits associated with displacing conventional carbon emitting generation with renewable generation.
- **Value of other economic benefits** – which is calculated as creation of direct and indirect employment from renewable generation in NI.

[61] Forgone revenues from the CCL are not included as a cost to NI public purse, as these are a cost to the UK exchequer as a whole.