Metering Options for Small-Scale Renewable and CHP Electricity Generation in Ireland

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Report prepared on behalf of Sustainable Energy Ireland by ILEX Energy Consulting

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EXECUTIVE SUMMARY

This study is intended to outline policy options relating to implementation of two-way metering in Ireland and inform policy on complex associated issues for renewable and CHP small-scale embedded generation (SSEG). In order to provide focus for the study, "small-scale" generators have been defined as those with a capacity of up to 1MW.

The study first describes and evaluates the full range of metering and payment options and then subjects four potential solutions to economic analysis. The results of this evaluation and analysis are described and used to draw conclusions about the appropriateness of the solutions for various generator types at various scales. Finally, the study reviews other barriers to further penetration of SSEG in Ireland.

Metering and payment options

The options for two-way metering of small-scale embedded generation combine three ways of metering and four quantities that can potentially be metered.

The ways of metering, in order of increasing expense and accuracy, are:

- not metering and, potentially, estimating quantities;
- non-interval metering: metering aggregate energy flows over periods longer than those used to settle wholesale power; and
- interval metering: metering energy flows within the time-frame used to settle wholesale power.

In Ireland, existing interval meters record data quarter-hourly. "Interval metering" and "quarter-hourly metering" are therefore used interchangeably in this report.

The quantities that can be metered are:

- import: the amount of energy imported from the network – if there is no generation on site, this will be the same as consumption;
- export: the amount of energy exported to the network – with no demand on site this will be the same, net of auxiliaries, as generation;
- generation: the total gross output of the generator, wherever consumed; and
- consumption: the total amount of energy consumed at the site, wherever generated.

In addition, it is possible to measure net import/export as a single value. This is known as net metering.

The metering options each have implications for the settlement system. Any SSEG connected to the electricity network will alter the flows of energy in the network and therefore affect payments between providers and users of the whole electricity system. If the SSEG is interval metered, the data obtained from the meter can be used directly in the settlement system in the same way as data from larger generators. Non-interval metered generation can be settled on profiles. Because profiles are not perfectly accurate, they introduce a degree of 'unfairness' into the settlement system that will grow as SSEG penetration increases. With no specific provision for settlement of export, and/or no metering, any exports not metered and 'spilled' to the network will be treated as negative losses.

Economic analysis

The economic analysis within this study focuses on the costs and benefits and other implications, in the short and longer term, of adopting various metering and settlement solutions for SSEG in Ireland. The analysis seeks to propose generator size and market penetration thresholds at which various types of solution might be appropriate.

To simplify interpretation of the analysis, the study analyses four metering and payment solutions that are clearly differentiated in terms of their costs. These are:

- "Not metering": not metering generation and using estimates as a basis for any reward scheme;
- "NQH IEG metering without profiles": metering Import, Export and Generation non-quarter-hourly, but without specific provision for settlement;
- "NQH IEG metering with profiles": metering Import, Export and Generation non-quarter-hourly with settlement based on profiles; and
- "QH IEG metering": interval metering Import, Export and Generation.

In order to undertake the cost-benefit analysis, the study makes assumptions about how each of these solutions would be implemented at various scales. The analysis uses four scales, defined by the type of demand metering already in place and the nature of the generator:

- single-phase demand using whole-current metering with a single phase generator connected to the low-voltage supply;
- polyphase demand using whole-current metering with a single-phase generator connected to the low-voltage supply;
- polyphase demand using whole-current metering with a polyphase generator connected to the low-voltage supply; and
- CT-operated demand metering and a generator with a capacity of greater than 50kW.

In order to present results that are clear, relatively concrete and do not date in the rapidly evolving Irish market context, the economic analysis includes only costs directly related to metering and payment that are readily quantifiable. For the same reason, it focuses first on the costs of the various metering and payment arrangements to generators and assesses the benefits that would be needed to offset these costs. Any solution that failed to make economic sense for generators at a particular scale would either not be appropriate for that scale or require some other party to bear at least a portion of the costs.

The aim of the analysis is to determine the cost in present value terms per megawatt-hour of generation of each of the metering solutions over the life of the meter installed. This cost per megawatt-hour is equal to the payment per megawatt-hour required by the generator investing in the metering solution for its investment to break even, assuming that the generator bears all of the costs related to metering.

Results and conclusions

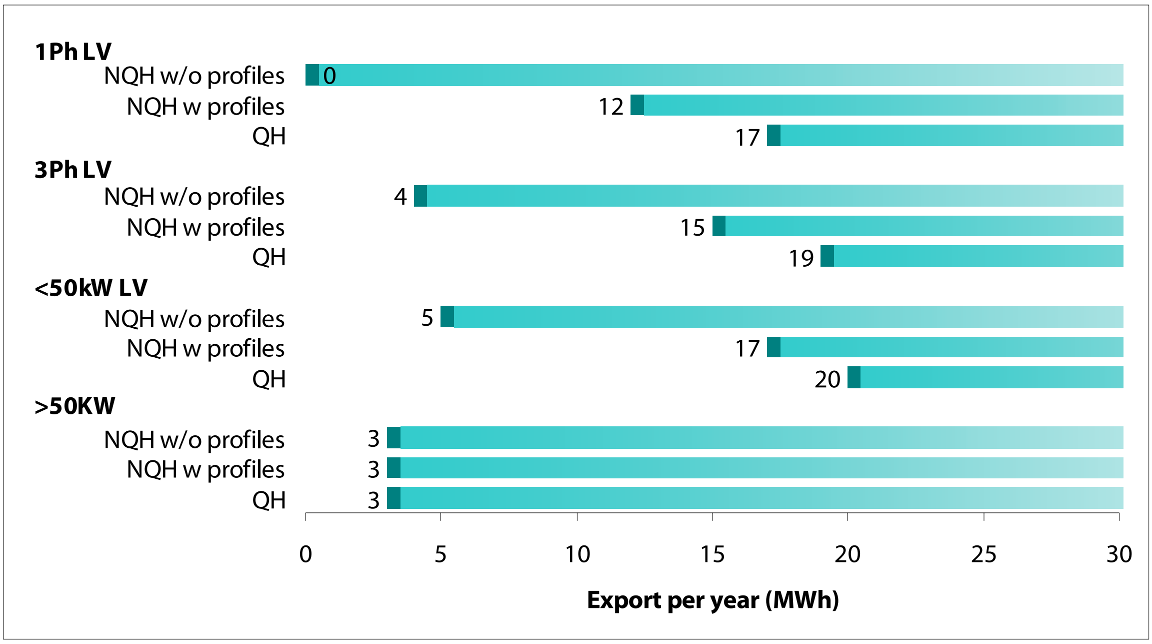
Assuming, conservatively, that exports are paid at €36.43 per MWh (half of the CER's proposed Best New Entrant Price for 2006), each of the four solutions would become viable at each of the scales studied as shown in Figure 1. The scale on the graph does not extend very far: metering costs are only an issue at the smallest scales of generation discussed in this study.

As an example of how to read the graph, at a domestic scale, with a single phase generator connected alongside single phase demand, NQH IEG metering without profiles becomes viable from very low levels of export (although bureaucratic costs, which have not been included in the analysis, may affect this result), NQH IEG metering with profiles becomes viable for generators with an export of 12MWh per year or more, and QH IEG metering is viable for generators with an export of 17MWh per year or more.

The results at the largest scale (a generator with a capacity greater than 50kW and CT-operated metering) merely imply that any of the solutions would be appropriate as they all become economically viable at an output of 3MWh per year, although a 50kW generator is likely to export far more than this.

Not metering, which has not been shown, is viable at all scales as it entails no direct quantifiable costs, although, as for NQH IEG metering without profiles, bureaucratic costs have been excluded from the analysis and may be significant for generators at the smallest scale.

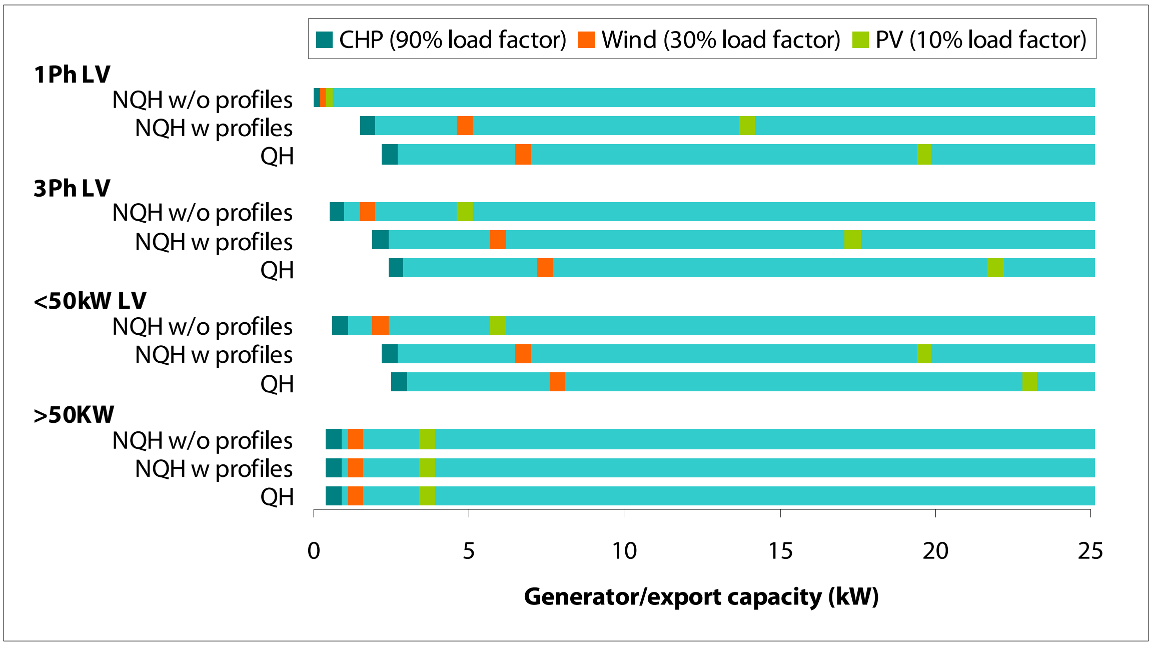
Figure 1 – Applicability ranges and thresholds for IEG metering solutions studied



Source: ILEX Energy Consulting

These megawatt-hour results can be translated into implied capacities for various types of generator based on typical load factors. The conversions for various technologies are shown in Figure 2. Note that these capacities are appropriate only if either all generation is assumed to be exported to the network (i.e. none of it is used to offset imports) or if they are thought of as the portion of a generator's capacity that exports.

Figure 2 – Applicability thresholds in capacity terms by technology



Source: ILEX Energy Consulting

Assuming that all generation is exported, then, in very approximate terms:

- Not metering is appropriate at all scales of generator.
- NQH IEG metering without profiles is appropriate for PV systems of 6kW capacity and up and other small renewable and CHP technologies of 2kW capacity and up.
- NQH IEG metering with profiles at low penetrations is appropriate for PV systems with a capacity of approximately 20kW and up and other small renewable and CHP technologies of greater than 8kW. For CHP plant with a high load factor, it could be viable for capacities as low as 2.5kW.
- QH IEG metering is appropriate for a similar range of sizes to NQH IEG metering with profiles at low penetrations.

These thresholds are determined by the highest capacity, at any scale, that each metering solution becomes appropriate for each technology. For example, NQH IEG metering without profiles becomes economically viable for PV at a capacity of approximately 0kW at the smallest scale, approximately 5kW for a polyphase low voltage customer with a single-phase generator, approximately 6kW for a polyphase low voltage customer with a polyphase generator and approximately 4kW at the largest scale (accepting that the largest scale is defined to include only generators larger than 50kW). As a result, unless the metering solution were to be differentiated by scale, then 6kW (the highest capacity at which this metering solution becomes viable for PV at any scale) is the lowest threshold at which this metering arrangement could be put in place without being economically unviable for some PV generators at some scales.

The lack of difference at low penetrations between NQH IEG metering with profiles and QH IEG metering should not disguise differences at high penetrations, where the high fixed costs of profiling under NQH IEG metering with profiles reduce rapidly per installation as penetrations increase whereas costs under QH IEG metering remain relatively high. Only in the case where high levels of quarter-hourly metering became the norm would QH IEG metering's costs fall substantially. Which solution is preferable will depend ultimately on balancing the superior 'fairness' of QH IEG metering against how costs fall in practice, expected penetrations and whether the assumptions used in this modelling hold true. In particular, it may be possible to use cheaper, if less accurate, profiles in the short-to-medium term than those assumed in this analysis.

Overall, the results suggest that for the smallest generators (at a domestic scale) either not metering or NQH IEG metering without profiles would be an appropriate solution. Both require the presence of some type of government-funded or mandated reward mechanism as the lack of a specific mechanism to settle generators' output under these solutions means that such output is almost certain to have no commercial value to suppliers. In addition, both of them entail bureaucratic costs that are uncertain and have not been factored into the analysis. At the smallest scales and at low penetrations, these costs will have a significant impact on the viability of these solutions if generators are asked to bear their full costs.

Which of these solutions is preferred and whether a generation meter is required will depend on the non-commercial factors discussed below. However, not metering could be implemented quickly, particularly if an appropriate feed-in tariff were already in place. NQH IEG metering without profiles would require more time, but would provide better quality data and would allow greater future flexibility, even keeping open the possibility of implementing NQH IEG metering with profiles for smaller generators if SSEG penetrations rise substantially or profiling costs fall well below the estimates used in this study.

For the largest generators in the study, quarter-hourly metering will inevitably be the preferred solution because of its superior accuracy and flexibility and because, at this scale, the costs of metering are immaterial relative to the rewards available.

The most difficult assessment to be made is which solution should be used for generators above a domestic scale, but below that at which quarter-hourly metering is the preferred solution. The study shows that it would be possible either to use whichever solution was chosen for the smallest-scale generators up to the threshold for quarter-hourly metering or to implement a third solution for generators at this intermediate scale. Such a third solution would have the significant disadvantage of added administrative complexity, but would offer an intermediate level of accuracy and cost that may be justified.

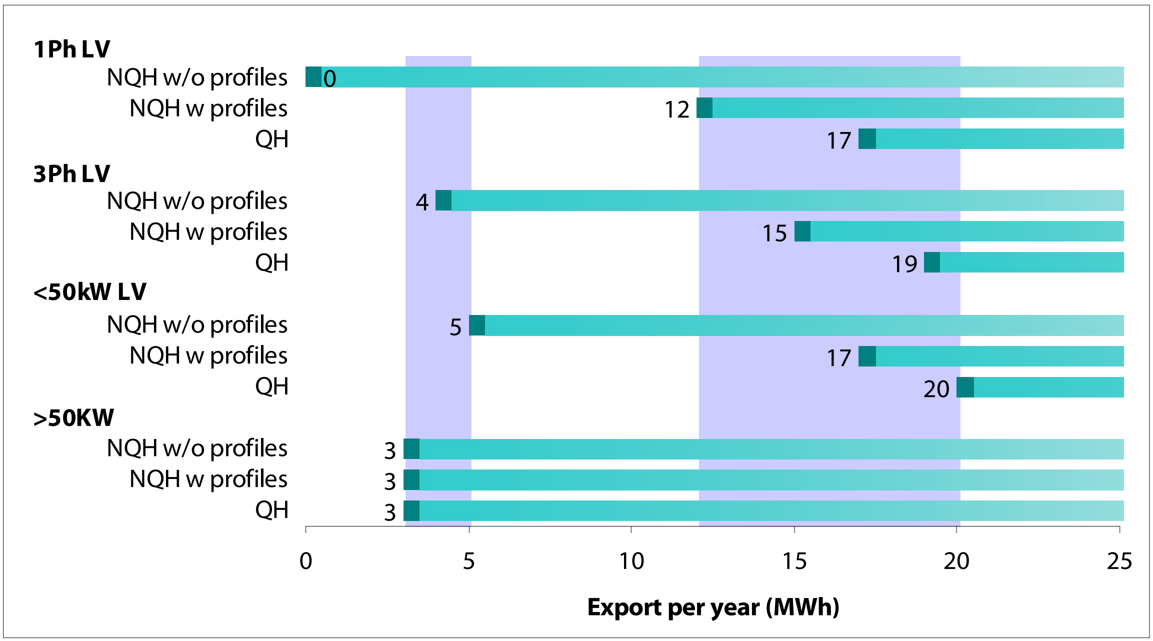
Other considerations
The focus of this study has been generators, for whom the decision to install metering will be largely driven by commercial considerations. However, the Irish Government, the CER, ESB National Grid, ESB Networks and suppliers will all have an interest in the solution chosen and their interests may result in certain solutions being mandated or, alternatively, excluded from consideration. These interests are likely to include, among others:

- accurate visibility of the flows of energy on the network and within the country as a whole;
- coherence with other meter replacement plans;
- future flexibility, particularly the risk of creating an installed base of assets that cannot meet future standards or participate in future reward schemes;
- the requirement to meet obligations imposed by EU Directives;
- any desire to harmonise arrangements with the North or with other jurisdictions; and
- the ability of existing systems to cope with SSEG.

Ultimately, concern, or the lack of it, about these issues may drive any requirement on generators to install a metering solution other than the one that provides them with the most economically favourable outcome and the allocation of costs resulting from such a solution.

Scale limits
Based on the results of the cost-benefit analysis described, there are two relatively clear thresholds for the applicability of the various metering and payment options analysed, bearing in mind that the assumed rewards for exports have been defined fairly arbitrarily. One threshold runs from an output of three to five megawatt-hours per year, equating, conservatively, to a generation capacity of three to five kilowatts. The second runs from an output of 12 to 20 MWh per year, equating, approximately, to a capacity of around 20kW. These thresholds are shown in Figure 3.

Figure 3 – Thresholds for metering and payment of SSEG



Source: ILEX Energy Consulting

These values could be used as the basis for thresholds in themselves or could be mapped onto some existing thresholds. The most relevant limit appears to occur at 50kW, the EU definition of microgeneration. Although this is considerably above the 20kW threshold suggested by the analysis, it may be appropriate for two reasons:

- Thresholds need to take into account the likelihood that only a portion of a generator's output will be exported. For PV, which several studies have shown exporting in the region of 50% of its generation a year, the threshold would need to be doubled to arrive at a realistic threshold for the total installed capacity, rather than the export capacity. For generators whose output is better matched to demand and who therefore export a smaller proportion of their generation this multiple will be higher.
- Thresholds should be set high enough that they are highly unlikely to prevent the installation of an appropriate meter or harm the economics of an otherwise viable installation.

The other potentially relevant existing threshold is the threshold for simplified connection of microgeneration used in Northern Ireland, which is set at 5kW for single-phase generators and 15kW for three-phase generators. ILEX understands that ESB Networks is considering introducing a simplified connection process for microgenerators at a capacity of around 10kW. This threshold would also be appropriate for metering. Although using the Northern Ireland thresholds might harmonise practices in the two jurisdictions, applying the NI connection thresholds to metering has the disadvantage that there is limited justification, in economic terms, for applying a different threshold to polyphase generators. As a result, the ESB Networks 10kW threshold may be more appropriate, if it is to be adopted.

It is worth noting that the results of the analysis suggest there is little economic rationale for differentiating the threshold by 'scale' (here used primarily to represent the type of metering already in place). The differences between costs of each of the four solutions tend to be greater than the differences in costs of the same solution at different scales, provided that the assumptions made in this analysis about the technical requirements of metering at each scale hold true. As a result, we do not believe that thresholds based on the type of metering already in place at the site would be appropriate.

However, the analysis shows that it would make economic sense to differentiate the threshold by technology, especially for technologies, such as PV, that have reasonably consistent load factors are not controllable. However, such differentiation would add considerably to the complexity of arrangements for SSEG and, as a result, we believe that appropriately conservative thresholds covering all technologies are likely to be a more practical option.

Potential solutions

The scale limits discussed above, combined with the results of the economic analysis, suggest four potential solutions around the two thresholds, as shown in Table 1.

Table 1 – Potential solutions

Generator capacity	**0 – 10kW**	**10kW – 50kW**	**50kW +**
Potential solution A	Not metering	NQH IEG w/o profiles	QH IEG
Potential solution B	Not metering	NQH IEG w profiles	QH IEG
Potential solution C	NQH IEG w/o profiles	NQH IEG w/o profiles	QH IEG
Potential solution D	NQH IEG w/o profiles	NQH IEG w profiles	QH IEG

Source: ILEX Energy Consulting

If not metering is considered unacceptable, then Potential Solution C (in which meters are installed, but no profiling is implemented for generators up to 50kW capacity) would appear to offer a strong combination of speed of implementation, future-proofing (always allowing a later move to Potential Solution D, for example), accuracy and data availability. However, it would require the presence of a feed-in tariff or similar reward mechanism to be effective.

Market barriers and areas for further work

In addition to the metering and payment solution, there are a number of other barriers to the uptake of SSEG in Ireland. Some of these barriers are common to markets everywhere, while others are specific to the Irish context. These barriers include:

- the capital costs of some renewable and CHP SSEG technologies;
- the application of the Public Service Obligation Levy to sites with generation designed to meet on-site load;
- export tariffs and the ability of SSEG generators to secure them, although this may change with the introduction of a feed-in tariff;
- uncertainty and changes resulting from market liberalisation and the introduction of the Single Electricity Market (SEM);
- the connection approval and charging process;
- connection standards for generators at the smaller end of the scale in this study;
- the definition of CHP;
- the illegality of private wire networks and wheeling;
- uncertainty over the future incentive scheme for renewable and CHP generation, although an announcement on the form of the feed-in tariff may resolve this;
- installer capacity and expertise; and
- awareness.

Given the limited consideration given to SSEG to date in Ireland, particularly at the smaller end of the scale, much work remains to be done in analysing appropriate arrangements to enable SSEG to compete equably in the market. Particular areas of focus could include:

- An analysis of the ability of renewable and CHP SSEG to secure adequate payment for their exports;
- A review of connection standards and the connection process for smaller generators; and
- An analysis of the implications of the SEM for SSEG.

1. INTRODUCTION

This study is intended to outline policy options relating to the feasibility of implementing "two-way metering" in Ireland and inform policy on complex associated issues for renewable and CHP small-scale embedded generation (SSEG). In order to provide focus for the study, "small-scale" generators have been defined as those with a capacity of up to 1MW.

The study has been commissioned by Sustainable Energy Ireland in response to the EU Renewables Directive (2001/77/EC) and CHP Directive (2004/8/EC). Article 6(2) of the Renewables Directive places an obligation on Member States to evaluate and publish a report on the electricity market legislative and regulatory framework with regard to procedures that are applicable to renewable electricity production plants. Article 7(7) of the Renewables Directive requires that this report shall examine, inter alia, the feasibility of introducing "two-way metering".

Article 8 of the CHP Directive states that "Member States should take the necessary measures to ensure that the tariffs for the purchase of electricity to back-up or top-up electricity generation are set on the basis of published tariffs and terms and conditions" and that "Member States may particularly facilitate access to the grid system of electricity produced from high-efficiency cogeneration from small-scale and micro-generation units."

This introduction sets out the context for the study and describes the contents and structure of the report that follows.

1.1. Irish market context

This report is written at a time of rapid change in the Irish electricity market. These changes will have significant implications for the future of renewable and CHP small-scale embedded generation, as for all other market participants. Indeed, almost all of the regulatory and electricity market factors that affect the installation and operation of SSEG are currently or will soon be under effective review. However, it also means that many of the assumptions that would typically be relied on in a study of this kind are in a state of flux in Ireland at present.

Three changing factors in particular look set to have a substantial impact on the metering and payment of SSEG and are worth describing here. These are:

- the creation of a Single Electricity Market (SEM) as part of the All-Island Project (AIP);
- ongoing market opening in the Republic of Ireland ("Ireland" or "the Republic") and Northern Ireland ("the North"); and
- changes in the primary renewables and CHP generation support mechanism in the Republic.

This section briefly introduces each of these in turn.

1.1.1. The Single Electricity Market

In August 2004, the regulators in the Republic (the Commission for Energy Regulation or "the CER") and Northern Ireland (the Northern Ireland Authority for Energy Regulation, or "the NIAER") signed a memorandum of understanding agreeing the principles that will underpin the development of a single electricity market on the island. Their aim is to have the market in operation by July 2007. A proposed high-level design for the market was published at the end of March 2005 and work on integrating the two markets is ongoing.

Some specific features of the proposed market design will have implications for SSEG and these are noted at appropriate points in this report. However, its overall effect will be to increase the pressure to harmonise policies and regulations, including those affecting SSEG, between the Republic and the North. As a result, this report refers to both the Republic and the North to highlight where practices differ at present.

1.1.2. Market opening

In the Republic of Ireland, the first steps to market liberalisation were taken in February 2000. Full retail competition for all electricity customers was introduced on 19 February 2005. Initially, the supply market was open for customers with an annual demand of greater than 1GWh. In February 2002, this threshold was lowered to 100MWh. In addition, the market for supply of "green" or CHP-produced electricity was open to all customers. This gave such suppliers a head start in the retail supply market, which has now been removed. The transmission and distribution businesses remain regulated monopolies run by ESB National Grid (soon to become EirGrid) and ESB Networks, respectively.

1.1.3. Changes in the renewables and CHP support mechanism

Between 1995 and 2005, renewable and CHP power of various types has been supported by a government-mandated support scheme known as the Alternative Energy Requirement (AER). In the six rounds of the AER, generation projects that fitted the tender round's criteria, which were usually specified by technology and, sometimes, project capacity, bid competitively to receive a fixed price for their exported energy for 15 years. The costs of the AER are recovered through a levy on customers' supply bills known as the Public Service Obligation (PSO) Levy.

Some renewable plants have been built without support from the AER; for example, Airtricity's Arklow Bank project which began operation early in 2005. In addition, the first AER plants will shortly face expiry of their power purchase agreements (PPAs) and therefore will be required to generate without subsidy.

In 2004, the Department of Communications, Marine and Natural Resources (DCMNR) began a consultation process on an 'interim' support measure to help Ireland achieve its target under the Renewables Directive of 13.2% of electricity being supplied by renewable sources by 2010. In April 2005, the energy minister, Noel Dempsey announced that the AER would be replaced by a fixed feed-in tariff. Details of the tariff are not yet known.

1.2. Contents and structure of the study

The study's primary aim is to analyse the feasibility of implementing two-way metering of some kind for renewable and CHP small-scale embedded generation. To achieve this aim, the study proceeds through a series of sections that reflect the critical elements of making such a decision:

Section 2 presents an overview of the possible metering and payment arrangements for small-scale embedded generation. These are initially presented without being pre-screened according to their costs, feasibility in Ireland or other criteria: the aim is simply to describe all of the potential options. Following the description, the study analyses the pros and cons of each option with regard to its costs (in relative terms for both generators and the electricity system) feasibility and practicality in the Irish market (to the extent that the form of the market is yet known), flexibility (which may be an important consideration given the changes now occurring) and 'fairness'. At the end of the section, four options are selected that are clearly differentiated in terms of their costs for further economic analysis.

Section 3 takes the four options selected and subjects each of them to a cost-benefit analysis. The analysis focuses on whether generators, if they were to bear all of the direct and readily quantifiable costs of installing and operating metering equipment themselves, could earn sufficient reward to make such a metering investment worthwhile. This must be the first test of whether a particular metering solution is appropriate at a particular scale. If a solution fails this test, either some of the costs must be borne by other parties or a less expensive solution is required. The section then discusses the implications of the solution for other parties, including suppliers, the Distribution System Operator (DSO), the Transmission System Operator (TSO) and electricity customers. Finally, the section discusses the results of the cost-benefit analysis in the context of the Irish market, suggesting the metering and payment arrangements that might be appropriate in the Irish market, in the near and longer term.

Section 4 looks at the scale limits that might be appropriate for metering and payment of small-scale embedded generation in Ireland. It provides a brief introduction to scale limits and then reviews the limits that currently exist in Ireland and other jurisdictions that may be relevant. In addition, it provides an overview of the possible ways that scale limits for the purposes of metering and payment can be defined. Finally, it draws on the cost-benefit analysis and conclusions from section 3 to suggest some scale limits that might be appropriate.

Section 5 steps back from metering and payment to look at barriers to the greater implementation of SSEG in Ireland more widely. It describes and analyses the various commercial, technical, regulatory and other barriers. In addition, where appropriate, it notes whether similar barriers apply in the North.

Finally, section 6 suggests areas that may reward further study.

2. REVIEW OF METERING AND PAYMENT OPTIONS

This section describes the range of metering and payment options that could be used for small-scale renewable and CHP generation in Ireland. It begins with a review of the context for metering in Ireland, including a summary of the meters currently in use and the existing presence of small-scale embedded generation. It then presents the full range of potential metering options, assessing each with particular regard to its feasibility in the Irish market and its ability to result in a fair outcome for generators and other relevant parties. Finally, it outlines the options to be subjected to the economic analysis presented in section 3, giving the reasons for each choice.

2.1. Metering systems currently in use in Ireland

In considering the options for metering SSEG in Ireland, it is necessary to understand current metering practices, both in the Republic and in Northern Ireland. In particular, the choice of metering for SSEG may be affected by the metering arrangements currently used for demand of a similar scale. For example, the type of demand metering may determine whether existing meters would need to be replaced once generation is installed at the same site. This section briefly reviews current metering practices in order to set the context for the subsequent discussion.

2.1.1. Republic of Ireland

In the Republic, electricity is metered quarter-hourly but settled half-hourly. In total, there are just over two million non-quarter-hour meters in the Republic of Ireland, of which some 20,000 are changed each year. Meters do not have a certified life. Instead, replacement rates are planned on the basis of samples. Some 600,000 non-quarter-hour meters are more than 20 years old and 160,000 more than 30 years old. In addition, there are approximately 14,000 quarter-hour meters, of which half are remotely read. All of the meters that are settled half-hourly are read remotely.

The majority of domestic customer demand sites are metered using electromechanical meters with back-stops that prevent them from running in reverse. Three-phase commercial customer demand is similarly metered using electromechanical meters with back-stops.

Commercial and industrial customers with a demand greater than 50kVA use polyphase CT-operated metering with registers for both import and export, regardless of the presence of on-site generation. These meters typically meet the GB's Code of Practice Five (CoP 5) standard.

Customers with a demand of greater than 100kVA are required to have meters that are 'online' in order that their data can be read daily automatically. All other meters are read manually, with data entered by the meter-reader into a keypad on hand-held units. There are trials underway of alternative automated meter reading systems for non-quarter-hourly meters. However, all of these are at an early stage.

Metering for small-scale embedded generation has recently been limited to those plants benefiting from a power purchase agreement under the AER. All of these plants are required to have quarter-hourly metering of import and export installed and to be on-line.

2.1.2. Northern Ireland

In Northern Ireland, electricity is metered and settled half-hourly. There are some 720,000 meters of which 665,000 are for domestic customers. Meters are certified in accordance with the Northern Ireland Meter Certification Regulations 1998. The regulations would require replacement of 50-60,000 meters per year. However, the current replacement rate is closer to 10-15,000 meters per year and NIE is pushing for a sampling approach to determine replacement rates.

The domestic meters are a mix of electromechanical (c. 60%) and electronic (c 40%). Some 90% are single rate. The vast majority of the electromechanical meters installed have back-stops, but some have no back-stops and are therefore capable of running backwards. There are no records of the location of those meters without back-stops.

Of the polyphase meters in place, some 60-70% are whole current. The threshold for CT-operated metering is set at 70kVA.

At present, sites with small-scale embedded generation are required to have half-hourly metering to CoP 5 standards in place. Two meters are installed, one at the customer's point of connection to the network to record import and export and a second on the generator terminals, pulsing back to the first.

Of the domestic meter population, 175,000 are pre-payment meters. As an anti-theft measure, the prepayment meter registers count forwards even when energy flows backwards.

2.2. Review of metering options for SSEG

The options for metering small-scale embedded generation combine three ways of metering and four quantities that can potentially be metered.

The ways of metering, in order of increasing expense and accuracy, are:

- not metering and, potentially, estimating quantities;
- non-interval metering: metering aggregate energy flows over periods longer than those used to settle wholesale power; and
- interval metering: metering energy flows within the time-frame used to settle wholesale power.

Because metering expenses are largely fixed, the larger the generator, the lower the importance of the cost of metering. Conversely, the larger the generator, the more important accurately recording its output becomes, for both commercial and technical reasons. As a result, the metering solution appropriate for one scale of generation may not be appropriate at another.

In Ireland, existing interval meters record data quarter-hourly. "Interval metering" and "quarter-hourly metering" are therefore used interchangeably throughout this report.

The quantities that can be metered are:

- import: the amount of energy imported from the network – if there is no generation on site, this will be the same as consumption;
- export: the amount of energy exported to the network – with no demand on site this will be the same, net of auxiliaries, as generation;
- generation: the total gross output of the generator, wherever consumed; and
- consumption: the total amount of energy consumed at the site, wherever generated.

In addition, it is possible to measure net import/export as a single value. This is known as net metering. It requires a single free-running meter that runs forwards when net import is positive and backwards when it is negative. As a result, the meter register may show negative/decreasing readings.

The metering options each have implications for the settlement system. Any SSEG connected to the electricity network will alter the flows of energy in the network and therefore affect payments between providers and users of the whole electricity system.

If the SSEG is interval metered, the data obtained from the meter can be used directly in the settlement system in the same way as data from larger generators. Provided the market's cost allocation rules are designed to take into account the costs and benefits of small-scale embedded generation, settlement can be both simple and 'fair'. However, in itself, this does not guarantee that SSEGs will be fairly paid for their output.

Non-interval metered generation presents more of a problem. Non-interval metered demand is settled by taking the aggregate volume of demand and allocating it to specific wholesale market periods using an appropriate profile. Profiles are designed to reflect the demand of an average user. Ireland uses eight demand profile 'classes' that are determined by the nature of the customer's demand and its tariff.

In theory, non-interval metered generation can also be settled on profiles. These profiles must be technology-specific (because different generation technologies generate different amounts at different times), and can be for export and/or import or for generation only. These options are discussed in more detail in the relevant section. However, because profiles are not perfectly accurate, either at an individual level or in aggregate for each wholesale market period, they introduce a degree of 'unfairness' into the settlement system, which will grow as SSEG penetration increases. In practice, for generation, as for demand, there will be a threshold at which the costs of interval metering small amounts of energy outweigh the benefits of increased accuracy.

In systems with no specific provision for settlement (often accompanied by no metering) of export, any output from SSEG at a site with existing demand will reduce the readings of the consumption (now import) meter at the site and may change the site's profile of demand from the network. In this case the supplier of electricity to the site will see its demand reduced. However, because the profiles used for settlement will take no account of this generation, they may become inaccurate. At low penetrations of SSEG, this effect will be immaterial, but at higher penetrations it could materially affect the accuracy of the settlement system.

Any exports not metered and 'spilled' to the network will be treated as negative losses and their value will effectively be credited to all suppliers operating in the same area. Demand that is not metered or profiled (e.g. theft) is treated in the same way.

Sections 2.2.1 to 2.2.3 below analyse the three ways of metering in turn, with reference to each of the four quantities and net metering, where appropriate.

2.2.1. Not metering

At its simplest, not metering can mean ignoring the generator's output completely. Where the generator is connected to meet on-site demand, the generation operator would still benefit from reduced energy imports from the network, but, assuming the meter cannot run backwards, any exports would be ignored.

Alternatively, where the generator's output is not metered its gross generation may be estimated[1]. Such estimates would need to be technology-specific and based, at least, on generator capacity and a standardised load factor.

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[1] Note: Estimating net import/export is impractical as this value is too site-specific for estimates to be reliable; estimating import and export separately is also difficult, for the same reason

To improve their accuracy further, estimates may also take into account geographic variations (in wind regimes, average irradiance, temperature and so on) and, potentially, the characteristics of specific types/makes of technologies: for example, types of solar photovoltaic (PV) cells with a greater or lesser efficiency. The latter refinement would require type approval of all technologies that might wish to be rewarded on the basis of estimated generation.

Estimated generation can be rewarded in the same ways as actual generation. At present, estimated generation is being used as the basis on which to award Renewable Energy Certificates to very small generators (typically under 10kW capacity) in Australia[2]. In theory it could also be profiled and settled as though it were metered using non-interval metering, although there are no examples of this method being used in practice that we are aware of.

Not metering, but estimating, generation has the clear advantage of costing the generator very little. With no new meter installed or read, the two main costs of metering are removed. However, with no provision to settle energy exports, such a scheme would need to be accompanied by some type of government mandated or sponsored reward mechanism, such as the proposed feed-in tariff. This would entail administrative costs, although the level of these would depend on how tightly the government wished to control the scheme. Tight control, including technology type approval, annual declarations and regular auditing would entail much higher costs than a scheme that was more prepared to operate on trust. However, the level of control could be adjusted as market penetrations increased, allowing a useful flexibility.

Estimating generation has five main disadvantages. First, it is open to various kinds of abuse that may extend to fraud. At best, systems temporarily off-line will be rewarded as though they were generating. At worst, once a system has been registered, it could be moved, re-installed and re-registered elsewhere. As a result, any such system would need to recognise the potential for fraud and provide a system for auditing the performance (and presence) of registered systems.

Second, estimating generation will be less accurate both in aggregate and for individual generators than measuring it. As a result, it will inevitably produce some unfairness within the system. The direction and magnitude of such 'unfairness' will be difficult to predict, but will have implications for the cost-effectiveness of such a solution, especially as the penetration of SSEG increases.

Third, the system cannot be fair, for although the non-market value[3] of the generation can be rewarded based on estimated generation, the market value of exports cannot be accurately rewarded. In addition, by spilling onto the network, generators would decrease the accuracy of the settlement system and potentially mask the true extent of system losses from sources such as theft.

Fourth, because the generator offsets demand, the DSO will not know the true demand of the customer and what strain this might place on the network should the generating equipment fail. However, it may consider that the risk is minimal and would anyway be mitigated by a requirement to state the maximum import capacity (MIC) of the site to the DSO, as currently happens in Ireland. It may also be concerned about its ability to recover its costs via the remaining demand at the site through now-reduced kilowatt-hour charges.

Finally, it is questionable whether estimating values would be acceptable for the purposes of providing guarantees of origin for 'green' generation under the Renewables or CHP Directives.

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[2] See Australian Renewable Energy Regulator Web site: http://www.orer.gov.au/householders/smallgenerationunits.html

[3] Note: "Non-market" is used here to refer to values for which no market exists, such as environmental, social and other benefits. This contrasts with "market" benefits, which are those for which a ready market exists, such as electricity.

2.2.2. Non-interval metering

Non-interval metering records the relevant quantity/ies in aggregate over a time period much longer than the interval used for trading in the wholesale market. In Ireland, for example, the market operates in 30-minute blocks whereas ESB currently aims to read non-interval meters once every two months. The quantity aggregated may be differentiated by time of day. For example, the meter might record aggregate generation at peak times on one register and aggregate generation at other times on a second register.

Non-interval meters can be used to record all four quantities and to net meter. This section describes the configuration and advantages and disadvantages of each.

2.2.2.1. Net metering

In net metering, a single non-interval meter is used to record all import and export from a site between meter readings. To achieve this, the meter runs forward when recording import and backwards when recording export. As a result, the register can increase, decrease or stay the same between meter readings.

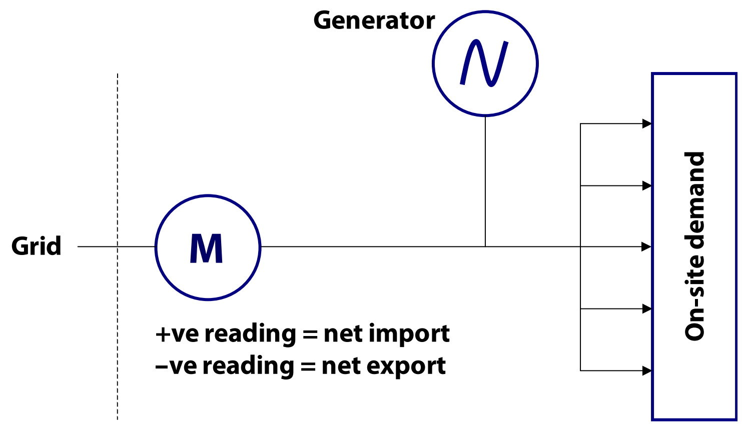
Net metering provides its own form of reward system by crediting all generation at (typically) the full retail rate that the customer pays for demand. Some net metering systems differentiate the rate paid by the customer for net increases in the meter reading (imports are greater than exports in the period) from that paid by the supplier for net decreases (exports are greater than imports). Typically, the former must be paid for at the full retail rate, the latter at a lower rate based on wholesale market prices or a proxy. This approach allows net metering to be used for sites where generation is sized to more than meet demand.

Net metering may be combined with net billing, in which individual meter readings can be summed over a longer time period, and the customer billed or paid on the longer period. This is likely to be favourable for sites where export exceeds import at certain times of the year and not at others.

The data collected by the meter is settled on the demand profile used for the customer. The substantial variations in individual site conditions are likely to result in profiling that is likely to be unacceptably inaccurate to market participants, particularly as the penetration of small-scale generation increases.

A typical net metering configuration is shown in Figure 4.

Figure 4 – Net metering configuration



Source: ILEX Energy Consulting

Net metering's potential advantages are its simplicity and low administrative costs. Because the reward system is effectively built in, governments typically need only to mandate suppliers to offer net metering tariffs and, perhaps, set a cap on the number of net metering customers a supplier is obliged to connect. Beyond some compliance checking and/or monitoring of the scheme's performance, there are no administrative costs for government. Under net metering, the extra costs for suppliers (of administering generation customers and, in effect, of paying them a reward for their generation) will ultimately be borne by electricity consumers.

In contrast, net metering's disadvantages are manifold. Net metering offers no cost advantage in Ireland. In countries where existing demand meters are capable of running backwards, net metering is frequently used as a low-cost option as it avoids the cost of changing meters. However, neither in the Republic of Ireland or Northern Ireland is this the case and hence net metering would require the installation of a new meter. Such meters are only marginally less expensive than meters capable of recording two or three quantities separately.

Net metering lacks the flexibility to be 'fair' for all generators. This applies even in systems where the tariff for net import and net export are differentiated. It effectively allows generators to use their output to meet their demand, regardless of whether the output and demand coincide. The longer the period between meter readings (or, for net billing, bills), the less 'fair' the system will be.

If the tariffs for net import and net export are the same, then the increment to the market value of small-scale embedded generation implied by the tariff may coincidentally price-in the non-market values of the generation source. However, this can only occur by chance (it requires the margin the supplier makes on consumption to equal the non-market value created by the form of generation in use). In effect, the jurisdictions that use net metering accept that the tariff used incorporates these non-market values within a margin of error that they consider acceptable.

In addition, because net metering is very difficult to profile accurately, it produces relatively large inaccuracies in the settlement system, which also make it 'unfair'. However, this level of unfairness is only likely to become material at high penetrations of SSEG.

Net metering does not appear to be compatible with other forms of reward scheme based on metered volumes, such as the feed-in tariff recently announced for the Republic of Ireland or renewable energy certificate schemes, such as the Renewables Obligation now operating in Northern

Ireland. If it were to be combined with such a scheme, generation would need to be separately recorded or estimated.

Net metering does not permit tracking of the quantity of renewable or CHP generation. It is our understanding that this is a requirement of the EU Renewables and CHP Directives.

Because the generator offsets demand, the DSO will not know the true demand of the customer and what strain this might place on the network should the generating equipment fail. However, it may consider that the risk is minimal and would anyway be mitigated by a requirement to state the maximum import capacity (MIC) of the site to the DSO, as currently happens in Ireland. It may also be concerned about its ability to recover its costs via the remaining demand at the site through now-reduced kilowatt-hour charges.

Finally, net metering is more likely than other solutions to require changes to data handling systems if these are configured to reject significant decreases in the value recorded by a meter between readings. Most data handling systems will initially treat any current register reading that is less than the previous register reading (assuming the previous reading was not estimated) as a potential 'roll-over' of the register on reaching 9999. This is simply achieved by adding a '1' in front of the highest digit of the current register reading and re-performing the calculation. If the advance is now within acceptable limits, it is assumed that the meter register simply 'rolled-over' to 0000 at some point between the previous and current reading. However, if a net meter were subsequently to 'roll-back' to below 9999, the difference between the current and previous register readings could be seen as a large advance, probably outside acceptable limits, and consequently trigger an investigation. Meter registers vary in size, typically from four to six significant digits. The normal standards applied are that the meter shall not 'roll-over' more than once in any billing period. Clearly this may not be the case with a net meter.

Other problems will arise in billing programs designed to detect reverse running relating to potential fraud, which may require a re-design of the program, allowing it to operate with a small number of net meters: potentially an expensive exercise. Such a re-design would make it difficult to detect the use of a 'black box' for fraudulent purposes.

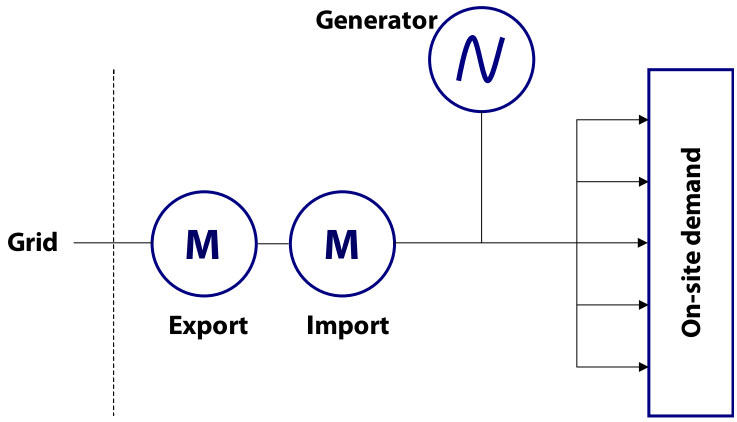
2.2.2.2. Import and export

In metering import and export, the generation equipment is connected on the customer's side of the point of connection to the network, allowing the customer to use its own generation to offset imports from the network. The metering records aggregate imports from the network and, separately, aggregate exports.

In practical terms, the two quantities can be recorded by the same meter. In Ireland, for all sites except those with CT-operated import-export metering already installed, this would require the existing meter to be exchanged for a bi-directional one. Polyphase bi-directional meters are becoming more widely available from European manufacturers. Alternatively, a second meter, reverse wired, could be installed, but this is inelegant for single phase meters and fundamentally poor engineering practice for polyphase, since the additional complexity of the wiring could result in reverse phase rotation or increase the fire risk generated by the number of additional cable connections. At the small end of the generator scale, it also requires more physical space to accommodate the meter, which may pose a problem.

Figure 5 shows a simple metering import-export metering configuration for a site with on-site demand.

Figure 5 – Import and export metering configuration



Source: ILEX Energy Consulting

Despite its increased complexity, recording import and export offers considerable advantages, not only over net metering, but also over metering generation and consumption (described in section 2.2.2.3). Its key advantage is that it is can offer a truly 'fair' solution for the market value of the energy output of small-scale embedded generation. Generation that serves an on-site load displaces import and so effectively receives the full retail tariff. Generation that is exported to the network can be rewarded at a price determined by the market or set with reference to it, provided appropriate provisions are in place for any settlement.

The main proviso is that transaction costs for very small volumes of export are likely to be so high as to seriously undermine the market value of such export. This is true in Great Britain, where anecdotal evidence suggests that suppliers are prepared to offer a tariff for such export only to generators above a certain output threshold. Below this threshold, transaction costs exceed the value of the export.

In addition to its fairness, metering import and export offers the benefit over net metering of flexibility: in theory, the supply of energy to a site and the export of energy from it can be separate commercial transactions. This has the potential to add a competitive pressure to the electricity supply market by allowing a supplier to purchase energy from generators without supplying demand at the same site.

However, metering import and export has a number of disadvantages. In Ireland, for sites without existing CT-operated metering, import and export metering will require the installation of a new meter. This additional metering requirement brings with it not only the costs of the meter and installation (however they are apportioned) but also increased data handling costs, particularly if the export reading is used within the settlement system. Export data may additionally create problems within suppliers' billing systems that may be designed solely for charging customers for consumption.

Because the generator offsets demand, the DSO will not know the true demand of the customer and what strain this might place on the network should the generating equipment fail. However, it may consider that the risk is minimal and would anyway be mitigated by a requirement to state the maximum import capacity (MIC) of the site to the DSO, as currently happens in Ireland. It may also be concerned about its ability to recover its costs via the remaining demand at the site through now-reduced kilowatt-hour charges.

Settlement of metered import and export data presents difficulties. The presence of generation at a site with existing demand may alter the import profile at the site and requires a new profile to settle any export. These new profiles are likely to prove expensive to produce and complex or inaccurate or both. This stems from two factors. First, the profiles will be dependent upon the type of generation installed: PV, for example, will have a different generation profile from CHP plant. This would require profiles for import and export for each technology for each of the current demand profiles. Second, because individual sites are likely to have a broader distribution around the profiles produced, settlement accuracy will be reduced.

In practice, this level of complexity may not be necessary, at least in the near term. The British system effectively acknowledges that producing a full set of new profiles would be too costly and complex, instead ignoring small-scale embedded generation's impact on demand profiles and 'chunking' inverted versions of the current demand profiles to settle export. This process is described in further detail in Annex A.

Metering only import and export does not permit tracking of the total gross quantity of renewable or CHP generation, which may be important. It also may not be consistent with the guarantee of origin obligations contained in the Renewables and CHP Directives. However, the Directives are unclear on whether guarantees of origin should be issued on exports only, or on all generation.

Finally, metering of import and export is only partially compatible with common reward mechanisms and so, for renewable generation at least, cannot on its own be considered fair. To be fair, mechanisms designed to reward the non-market benefits of renewable or other environmentally advantageous generation should be awarded on total generation. As a result, paying such a tariff only on export rewards the wrong quantity. This holds true even if the mechanism is designed to reward both market and non-market benefits. In this case, the market benefit would be correctly paid on export, but paying the non-market benefit on export would still reward the wrong quantity.

This may not matter if the reward tariff for market and non-market benefits is fortuitously set close to the level of retail electricity tariffs, making the economics of displacing import and being paid the feed-in tariff on export and of not displacing import but receiving the tariff on all generation, identical. In some jurisdictions (e.g. France), this choice is left to the generator's discretion. However, it does not meet an ideal standard of fairness.

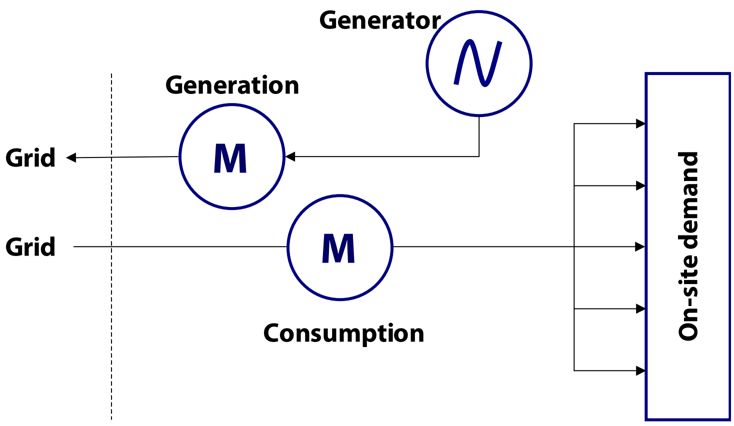
Similarly, the ROCs used in Northern Ireland to reward renewable generation are designed to reward only the non-market values of renewable generation (both energy and the ROCs earned can be sold in the market). As a result, a generator earning ROCs only on export as a result of the absence of a generation meter would gain only a portion of the benefit to which it was entitled and hence metering import and export only would not be compatible with the reward mechanism in place in Northern Ireland, either.

It is worth noting that no jurisdiction that we are aware of that rewards renewable or CHP generation through a feed-in tariff is concerned about these distinctions. Most feed-in tariffs are simply paid on all energy exported to the network and the distinction between market and non-market benefits is not made.

2.2.2.3. Generation and consumption

In metering generation and consumption, the generator would typically be connected to the network outside of the customer's own point of connection for demand. In Ireland, to measure generation and consumption at any of the scales within this study, a new meter will be required. This could potentially be a single meter with two measuring elements and two registers (of which one would replace any existing demand meter), but is most likely to be a separate second meter, owing to the connection requirements of metering generation. A typical configuration for generation and consumption metering at a site with on-site load is shown in Figure 6.

Figure 6 – Generation and consumption metering configuration



Source: ILEX Energy Consulting

Non-interval metered generation and consumption has the benefit of relatively simple settlement if profiled. Unlike import-export metering, only a generation profile for each relevant technology is required. Consumption (demand) profiles remain unaffected. Because the generation profiles do not incorporate demand variations, they should be simpler to produce and more accurate than profiles for export.

Generation and consumption metering shares the benefit of import-export metering that the two quantities may be contracted for with different parties.

In addition, metering of generation would allow the output from renewable and CHP generators to be tracked and would allow the DSO to understand exactly the potential strains on the network. However, it may not meet the requirements of the EU Renewables and CHP Directives, which are unclear on whether guarantees of origin should be issued on exports only, or on all generation.

Generation and consumption metering works well with renewable and other reward mechanisms, including feed-in tariffs and green certificate schemes. In itself, this is 'fair'. However, generation and consumption metering has one major drawback: it effectively denies the generator the ability to use its output to offset on-site consumption, instead forcing it to sell its generation. Because generation used to offset on-site consumption effectively receives the full retail rate for energy – including any margin the supplier makes – within a 'fair' framework, allowing generation to be used in this way will always be more economically favourable than selling it (assuming that any non-market credits are still paid on all generation). Generation and consumption metering can therefore not be considered 'fair'.

2.2.2.4. Summary

Table 2 below summarises the non-interval metering options and their interaction with settlement and reward mechanisms, and comments on their potential to be 'fair' and to comply with EU Directives requiring the issue of guarantees of origin.

Table 2 – Overview of potential metering and settlement options

	Net metering	Import – export	Generation – consumption
Settlement	Limited to single supplier Profiling very difficult	Separate supplier/ purchaser possible for each quantity Profiling difficult	Separate supplier/purchaser possible for each quantity Profiling relatively simple
Payment	Payment mechanism inherent, but must be government-mandated Not compatible with other forms of incentive scheme	Generation displaces import Export can be paid for either via market or via feed-in tariff. Only partially compatible with green certificate scheme	Generation not permitted to displace imports Generation can be paid for via market or via feed-in tariff/ green certificates
'Fairness'	Very unlikely to be 'fair': Likely to over-reward generator, usually at supplier's expense. Ultimate cost borne by supplier's customer base	Import displacement is 'fair' Value received for export likely to be diminished by transaction costs, but potentially 'fair' Impossible to reward non-market benefits of 'green' generation fairly	Denies generator ability to displace imports Allows fair reward of non-market benefits of 'green' generation
Monitoring	Cannot comply with EU directives	May not comply with EU directives	May not comply with EU directives

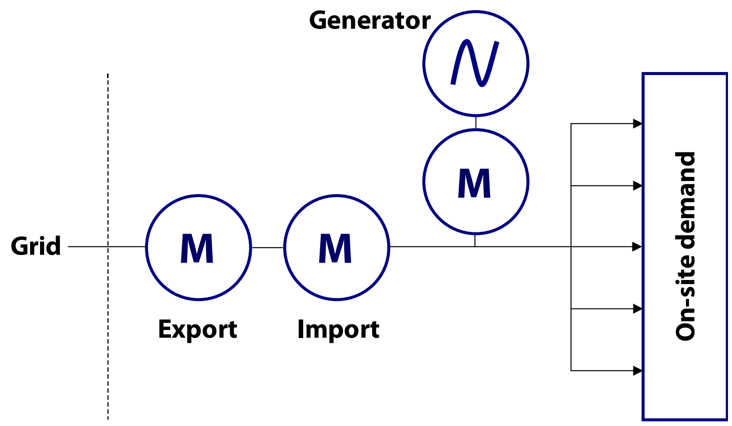
Source: ILEX Energy Consulting

2.2.2.5. Combinations

In addition to the basic options outlined above, it is, of course, possible, to meter more than two quantities. If such an approach were taken, one combination stands out as providing close to an 'ideal' solution. This would combine import-export metering – the 'fair' option for the market values of SSEG – with metering of generation to enable both rewards for the non-market values of 'green' generation to be fairly allocated and compliance with EU directives requiring the monitoring of renewable and CHP generation.

An example of a configuration in which import, export and generation could be metered is shown in Figure 7. Measurement of all three quantities can be achieved in a single dual-element meter. If it were deemed necessary, consumption data could be derived in real time from the other three values.

Figure 7 – Import and export metering with generation meter configuration



Source: ILEX Energy Consulting

For non-interval metering, this arrangement has the drawback that, even if exports from a site are spilled to the network, the presence of a generator will likely result in drift to the general import profile that may require the development of separate import profiles, in addition to spilling itself having negative consequences for the accuracy of the settlement system. As with many of these issues, this problem will become more important as SSEG penetration increases. Furthermore, because profiling export is more difficult than profiling generation and consumption, even settlement based on technology-specific profiles would result in a less than perfect solution.

2.2.3. Interval metering

Interval metering records data in the same time frame as that used to settle wholesale power. However, the costs of both the hardware and of data handling are much greater than for non-interval metering.

Interval metered data can be settled with complete accuracy as it does not require profiles. This gives an accurate base on which any purchaser of output from a SSEG can base a tariff.

The costs of settlement will depend partly on whether the meter must submit data within the settlement timescales and which requires a communications link of some kind, or whether the data can be collected less frequently by manual meter readers. The second option is not used in Ireland.

The other advantages and disadvantages of metering the various quantities remain the same as in the discussion of non-interval metering.

By removing the profiling difficulties associated with import-export metering, interval metering allows the creation of an 'ideal' metering solution that is both 'fair' and practical. In this solution import and export would be measured and settled. Payment for export could be left to the market or ensured via a market-reflective feed-in tariff. In addition, generation would be recorded and any rewards for the non-market values of green or renewable electricity applied to this quantity.

2.2.4. Metering of other quantities

In addition to metering kilowatt-hours of energy flow, at the larger end of the scale in this study it may be important to measure reactive power flows to ensure that there are no adverse impacts on the distribution network or on other customers.

Conversely, there may be opportunities for larger generators within the scope of this study to contribute actively to reactive power support or voltage control, and if this is to be recognised metering will be required to record and settle appropriate quantities.

2.3. Options for economic analysis

The economic analysis within this study focuses on the costs and benefits and other implications, in the short and longer term, of adopting metering and settlement solutions for SSEG in Ireland. The analysis seeks to propose generator size and market penetration thresholds at which various types of solution might be appropriate.

To simplify interpretation of this analysis, we have analysed options that are clearly differentiated in terms of their costs. The major costs involved in the solutions for non-interval metering are:

- installation of the meter; and
- settlement of metered volumes via profiling.

In addition, any interval-metered solution is likely to be more costly than any non-interval one.

As a result, in section 3 of this report we analyse the following four solutions:

- "Not metering": not metering generation and using estimates as a basis for any reward scheme;
- "NQH IEG metering without profiles": metering Import, Export and Generation non-quarter-hourly, but without specific provision for settlement;
- "NQH IEG metering with profiles": metering Import, Export and Generation non-quarter-hourly with settlement based on profiles; and
- "QH IEG metering": metering Import, Export and Generation quarter-hourly.

We do not believe it makes sense to analyse solutions that require the installation of a new meter that records fewer than three quantities (most likely import, export and generation). The incremental costs of such meters are generally low compared with meters capable of reading only one or two quantities. The more important costs are those involved in meter installation and the use of the data recorded. The latter costs are covered by comparing the use of such meters with and without settlement on profiles.

In addition, we do not analyse the costs and benefits of net metering. Although net metering is often seen as desirable by commentators, we do not believe that, in Ireland, it is an option worthy of further study. Because meters in Ireland are generally not capable of running backwards, it would require replacement of the existing meter. This new meter would be and its installation would be only slightly less costly than a meter capable of recording two or three quantities. As a result, we believe that net metering is a worse option (see section 2.2.2.1) than many other solutions at equivalent cost.

3. ECONOMIC ANALYSIS OF METERING AND PAYMENT OPTIONS

This section takes the options selected in section 2 and subjects them to a cost-benefit analysis. The analysis focuses on whether generators, if they were to bear all of the direct and readily quantifiable costs of installing and operating metering equipment themselves, could earn sufficient reward to make such an investment worthwhile. The section then discusses the implications of the solution for other parties. Finally, it suggests the metering and payment arrangements that might be appropriate in the Irish market, in the near and longer term.

3.1. Metering assumptions

In order to present results that are clear, relatively concrete and do not date in the rapidly evolving Irish market context, the economic analysis includes only costs directly related to metering and payment that are readily quantifiable. It therefore excludes, for example, the costs of connecting SSEG to the distribution system – which are not related to the metering decision – and the costs to suppliers of changing their customer management and billing systems to handle large volumes of SSEG – which are related to metering and payment, but are not readily quantifiable. For the same reason, it focuses first on the costs of the various metering and payment arrangements to generators and assesses the benefits that would be needed to offset these costs. Any solution that failed to make economic sense for generators at a particular scale would either not be appropriate for that scale or require some other party to bear at least a portion of the costs. In essence, the approach taken is to:

- define the direct costs of implementing the four metering and payment solutions chosen for the study, net of any direct benefits;
- assume that these net costs are borne by the generator;
- calculate the level of payment/reward required by embedded generators of various scales and characteristics for such metering arrangements to show a net benefit. Such implied payments/rewards would incorporate the impact of embedded benefits, balancing costs, bureaucratic costs and the like;
- assess whether the level of such payment/reward is, approximately, likely to be achievable; and
- provide additional supporting analysis on the costs and benefits to parties other than generators and comment on non-quantifiable costs and benefits.

The costs considered in the modelling of costs and benefits are:

- the meter asset and its installation;
- data collection, aggregation and settlement costs;
- the costs of meter operation services – an annualised cost reflecting the costs of meter servicing and maintenance, among others;
- the stranded asset costs resulting from early replacement of the existing demand meter, in some cases; and
- the costs saved by not having to replace the existing demand meter, in some cases.

In order to undertake a cost-benefit analysis, it is necessary to make assumptions about how exactly the general solutions identified in section 2.3 would be implemented in practice in Ireland. This implementation would vary with the scale of the installation. The analysis uses four scales based on different metering arrangements. These are defined by the type of demand metering already in place and the nature of the generator:

- single-phase demand using whole-current metering with a single phase generator connected to the low-voltage supply;
- polyphase demand using whole-current metering with a single-phase generator connected to the low-voltage supply;
- polyphase demand using whole-current metering with a polyphase generator connected to the low-voltage supply; and
- CT-operated demand metering and a generator with a capacity of greater than 50kW.

Sections 3.1.1 to 3.1.3 outline in detail the solution assumed to be implemented at each of four scales, providing the cost assumptions used in the modelling, and sections 3.1.4 and 3.1.5 describe the assumptions made in relation to the consequent stranded asset costs and savings to the DSO as a result of not having to install replacement demand metering. Throughout this section, meter and installation costs have either been provided by ESB or are ILEX's estimates based on conversations with meter manufacturers and experience.

3.1.1. Not metering

Not metering has the advantage for the generator that the direct costs of metering and payment are limited to the opportunity and other costs required to complete and submit any forms in order to secure whatever payments are available. No costs have been attributed to this in the analysis.

3.1.2. Metering import, export and generation non-quarter-hourly with or without profiles

Both non-quarter-houly solutions combine one metering option with two options for settlement. In the first, data from the import register is settled as usual. The export and generation readings are taken and may be used as the basis for rewards under the feed-in tariff, for example, but the data is not used in settlement. In the second, the data from the export register is assumed to be settled on a technology-specific profile. Generation data is recorded but does not enter the settlement system.

Non-quarter-hour metering is not believed to be realistic option for sites that already have quarter-hourly demand metering. As a result, within this option, the costs for sites with CT-operated metering assume that interval metering is used for export and generation as well as import. However, as at the other scales, in NQH IEG metering without profiles the export data is used as the basis for a flat per kWh reward tariff, whereas in NQH IEG metering with profiles it is settled half-hourly, allowing a variety of payment arrangements. In neither option is generation data settled.

3.1.2.1. Meter and installation costs

Under the non-quarter-hourly metering solutions, for the domestic single-phase market, an electronic bi-directional meter is assumed to replace the existing import meter. A second, separate meter standard credit type meter would be installed to record generation. The costs of these meters are assumed at €25 and €20, respectively at small volumes (500 installations), falling slightly to €20.50 and €20 after 5,000 installations. The average cost of installation is estimated at €50 and is assumed to fall to €45 as more meter fixers are trained in this type of work and jobs occur in neighbouring areas. In practice, it may be possible to re-use the existing credit meter as the generation meter, thereby saving €20 on the second meter, but this might present problems with meter registration and is probably not best practice.

For polyphase whole-current metered sites on the low voltage network with a single-phase generator of less than 3.7kW[4] capacity, the metering arrangement would be similar: an electronic bi-directional

[4] Equivalent to 16 Amps Single phase, UK Engineering Recommendation G83/1 and IEC 61000-3-2/3

meter to replace the existing import meter and a second meter to record generation. However, in this case the new meters would be more costly. We have estimated the cost of the import-export meter at €150 and that of the generation meter at €60, at low volumes. This falls to €135 and €54, respectively, after 5,000 installations. Installation costs are estimated to be similar to those at the domestic scale.

For polyphase whole-current metered sites on the low voltage network with a polyphase generator with a capacity less than 50kW, the solution would be similar to that at the smaller scales: two new meters, one to measure import and export and a second to measure generation. However, at this scale, it is most likely that both these meters would be CoP5 meters, entailing a further increase in cost to an estimated €150 for the import-export meter and €150 for the meter to record generation, at low volumes. These costs are estimated to fall to €135 and €135, respectively, after 5,000 installations. The costs of installing such an arrangement are estimated at €90 at low volumes, falling to €81 at high volumes.

Finally, for the largest scale sites, where CT-operated demand metering is installed (implying a demand capacity of greater than 50kW in the Republic of Ireland), the existing meter is assumed to be adequate to record export in addition to import. As a result, only a new generation meter would be required. The cost of this meter is estimated at €150 at low volumes and €135 as volumes rise beyond 5,000 installations. Installation costs are assumed at €150 at low volumes, falling to €135 after 5,000 installations, including the costs of additional CTs, which will almost certainly be required.

At this scale, non-interval metering is not appropriate and we do not believe it realistic that import and export would be either not settled, or settled on a profile. As a result, unlike at other scales, import and export is assumed to be settled half-hourly.

A summary of these costs is shown in Table 3 below. Meter and installation costs are the same for both non-quarter-hourly solutions.

Table 3 – Meter and installation costs for NQH IEG metering solutions

€	Scale			
	1Ph LV	3Ph LV	<50kW LV	>50kW
Meter cost				
<500	45.00	210.00	300.00	150.00
>500 <5,000	42.75	199.50	285.00	142.50
>5,000	40.50	189.00	270.00	135.00
Installation cost				
<500	50.00	50.00	90.00	150.00
>500 <5,000	47.50	47.50	85.50	142.50
>5,000	45.00	45.00	81.00	135.00

Source: ILEX Energy Consulting

3.1.2.2. Operating costs

For NQH IEG metering without profiles, the model assumes that the costs of data collection, aggregation and settlement are the same as at present for sites with demand metering only as data from the export and generation meters is not settled. Meter operation costs, which are an annualised estimated cost of meter maintenance and other routine and emergency services, are estimated based on data from Great Britain.

For NQH IEG metering with profiles, data collection, aggregation and settlement costs are double those in NQH IEG metering without profiles, reflecting the need to read and process data streams for both import and export. Meter operation costs are the same.

In both solutions, generators larger than 50kW are assumed to be settled half-hourly, using an existing communications link, both of which substantially increase data handling costs.

The total costs assumed are shown in Table 4. Note that for the purposes of the analysis, the data collection, aggregation and settlement and meter operation costs for the pre-existing demand metering at the site are deducted to arrive at an incremental cost of each solution. For NQH IEG metering without profiles, this incremental cost is zero.

Table 4 – Meter operation and data costs for NQH IEG metering

€	Scale			
	1Ph LV	**3Ph LV**	**<50kW LV**	**>50kW**
Data collection				
NQH IEG w/o profiles	7.50	7.50	7.50	480.00
NQH IEG w profiles	15.00	15.00	15.00	480.00
Data aggregation				
NQH IEG w/o profiles	20.00	20.00	20.00	60.00
NQH IEG w profiles	40.00	40.00	40.00	60.00
Settlement				
NQH IEG w/o profiles	1.00	1.00	1.00	20.00
NQH IEG w profiles	2.00	2.00	2.00	20.00
Operating costs				
NQH IEG w/o profiles	15.00	180.00	225.00	225.00
NQH IEG w profiles	15.00	180.00	225.00	225.00

Source: ILEX Energy Consulting

3.1.2.3. Profiles

The costs of establishing and maintaining new profiles for small-scale embedded generation have been based on estimates from Great Britain, where this process is currently underway. The estimates are that a profile for one technology costs €145,000 to create in the first instance and a further €55,000 each year to maintain. We have assumed that three profiles are created, one for each of the following technologies:

- photovoltaics;
- wind; and
- CHP.

In the short term, while penetrations remain low, these figures may well be an over-estimate. As the GB experience is currently showing, it would be relatively simple to estimate such profiles adequately in the first instance, amending them later as more operational data becomes available.

3.1.3. Quarter-hourly metering of import, export and generation

In some respects, interval metering of import, export and generation is the most internally consistent option, in that it can be applied fully to SSEGs at any scale. In this option, we have assumed that import and export data is settled and that generation data is used as the basis for a reward or monitoring scheme.

3.1.3.1. Meter and installation costs

For quarter-hourly metering at all sites, except those with existing quarter-hourly metering of import and export, new meters would be required: one to measure import and export and another to measure generation.

At the domestic scale, we have assumed that a new quarter-hourly import and export electronic meter is installed in place of the existing demand meter and their data settled. The generation meter at this scale is assumed to be a standard electromechanical meter on the assumption that generation does not need to be recorded quarter-hourly, unlike the other quantities. The costs of the import-export meter is estimated at €60 at low volumes and €54 each at high volumes. The electromechanical meter is assumed to cost €20 at all scales. In addition, even at a domestic scale, it is assumed that a communications link is installed, allowing the meter to be read remotely. This link is assumed to add €50 to the meter costs at low volumes and €45 at high volumes. Alternatively, a new dual-element meter designed to measure import, export and generation could be installed (similar in construction to an Economy 10 meter with the second element used to measure generation: this would be a special production run in the early stages). This may offer a slightly cheaper solution. Installation costs are assumed to average €50 at low volumes and €45 at high volumes.

For low-voltage polyphase connections with a single-phase generator of less than 3.7kW, the analysis assumes that the existing demand meter is replaced with a CoP5 import-export meter and a CoP6 or pulsing meter for the generation. The costs of these meters are estimated at €150 and €60, respectively at low volumes and €135 and €54 at higher volumes. Again, a communications link is assumed to add €50 to these costs at low penetrations and €45 at high penetrations. Installation costs are the same as for single-phase connections at this scale.

With a polyphase generator of less than 50kW, the replacement import-export meter remains the same, but in this case the generation meter is assumed to be a CoP5 meter, with a cost estimated at €150 at low volumes and €135 at higher volumes. A communications link is assumed to add €50 to these costs at low penetrations and €45 at high penetrations. Installation costs are assumed to average €60 at low volumes and €54 at high volumes, reflecting the greater complexity of installation.

For sites with existing CT-operated metering, the installation required is assumed to be the same as under the NQH IEG metering solutions.

A summary of these costs is given in Table 5 below.

Table 5 – Meter, installation and data costs for QH IEG metering

€	**Scale**			
	1Ph LV	**3Ph LV**	**<50kW LV**	**>50kW**
Meter cost				
<500	130.00	260.00	350.00	150.00
>500 <5,000	124.50	247.00	332.50	142.50
>5,000	119.00	234.00	315.00	135.00
Installation cost				
<500	50.00	50.00	60.00	150.00
>500 <5,000	47.50	47.50	57.00	142.50
>5,000	45.00	45.00	54.00	135.00

Source: ILEX Energy Consulting

3.1.3.2. Operating costs

For the interval-metered solution, we have assumed that all sites are on-line. The costs of data collection are therefore substantially higher than for the non-interval metered solution, at €480 per meter per year. The costs of data aggregation are estimated at €60 per year at all scales. The costs of meter operation vary with the nature of the metering installed. These cost estimates are shown in Table 6. Note that for the purposes of the analysis, the data collection, aggregation and settlement and meter operation costs for the pre-existing demand metering at the site are deducted from the costs discussed here to arrive at an incremental cost of this solution.

Table 6 – Meter operation and data costs for QH IEG metering

€	Scale			
	1Ph LV	**3Ph LV**	**<50kW LV**	**>50kW**
Data collection	480.00	480.00	480.00	480.00
Data aggregation	60.00	60.00	60.00	60.00
Settlement	20.00	20.00	20.00	20.00
Meter operation	67.50	180.00	225.00	225.00

Source: ILEX Energy Consulting

3.1.4. Stranded asset costs

Each of these metering solutions in which an existing demand meter is replaced would entail a level of stranded asset costs which, as for all costs in this section, we are assuming is passed directly and immediately through to the generator, in the first instance. The costs of stranding these assets are based on ESB's current rate of re-use of demand meters of each type, the costs of refurbishment, and the value of the meter (based on current costs). The average stranded asset cost per installation is therefore calculated as:

Percentage of meters refurbished x cost of refurbishing each meter

+

Percentage of meters not refurbished x cost of meter replaced x 50%

In this equation, we assume that the meters replaced were half way through their operating lives. The costs of the meters replaced and the costs of refurbishing meters of each type are assumed as set out in the table below. The costs of meters replaced are the current costs of each meter type in the market as this best reflects their value, rather than their cost at the time of installation.

Table 7 – Stranded asset cost assumptions

€	Scale			
	1Ph LV	**3Ph LV**	**<50kW LV**	**>50kW**
Percentage of meters refurbished				
Not metering	n.a.	n.a.	n.a.	n.a.
NQH IEG w/o profiles	60.0%	40.0%	40.0%	n.a.
NQH IEG w profiles	60.0%	40.0%	40.0%	n.a.
QH IEG metering	60.0%	40.0%	40.0%	n.a.
Cost of meters replaced				

Not metering	n.a.	n.a.	n.a.	n.a.
NQH IEG w/o profiles	20.00	120.00	120.00	n.a.
NQH IEG w profiles	20.00	120.00	120.00	n.a.
QH IEG metering	20.00	120.00	120.00	n.a.
Refurbishment costs				
Not metering	n.a.	n.a.	n.a.	n.a.
NQH IEG w/o profiles	10.00	18.00	18.00	n.a.
NQH IEG w profiles	10.00	18.00	18.00	n.a.
QH IEG metering	10.00	18.00	18.00	n.a.

Source: ILEX Energy Consulting

3.1.5. Costs saved by not replacing existing demand meter

Depending on the life of the new meter in comparison with the life of the old one, within the time-frame of the generator's investment decision, the installation of a new meter may save the DSO from having to replace an existing demand meter that it would otherwise have had to replace. This cost saving is included *pro rata* for the proportion of the life of this replacement meter that falls within the time-frame of the generator's investment decision. The values used for the future meters not installed are the same as those used for the calculation of stranded asset costs as it is assumed that there are no real cost reductions in the price of existing meters going forward.

Because the lives of quarter-hourly meters are relatively short, no savings are assumed for QH IEG metering: the new meters reach the end of their lives before or at the same time as the meters replaced would have reached theirs.

3.2. Generator cost-benefit analysis

The model's aim is to determine the cost per megawatt-hour in present value terms of generation of each of the metering solutions over the life of the meter installed. This cost per megawatt-hour is equal to the payment per megawatt-hour required by the generator investing in the metering solution in order for its investment in a metering solution to break even, assuming that the generator bears all of the costs related to metering identified above.

In order to complete this calculation, it is necessary to make assumptions on the life of the meter being installed and the discount rate used. In the model, meter lives are assumed at 20 years for all non-quarter-hourly solutions, including not metering and 10 years for the quarter-hourly solutions. The discount rate is more difficult to assess. We have a real, pre-tax weighted average cost of capital-based rate of 6.49%, reflecting the rate used in the CER's calculation of the Best New Entrant Price[5] (the underlying value used to determine top-up and spill prices in the Irish market).

Consumer discount rates are likely to be higher than this owing both to the higher costs of finance at small scales and to consumers own preferences. However, research on consumer discount rate produces highly variable results. As a result, we use a commercial rate of return throughout. It should be noted that the results of the analysis are anyway not highly sensitive to the discount rate.

Finally, it should be noted that the model analyses three levels of penetration of SSEG:

- low – i.e. below 500 installations;

[5] Reference: CER (2005) Best New Entrant Price 2006

- medium – i.e. between 500 and 5,000 installations; and
- high – i.e. above 5,000 installations, where appropriate.

For the not metering and NQH IEG metering with and without profiles solutions, these levels of penetration affect the analysis through the decreasing meter and installation unit costs described in sections 3.1.2.1and 3.1.3.1. However, the effect is not significant and therefore sections 3.2.1, 3.2.2 and 3.2.4 below present results from the low penetration case only. For NQH IEG metering with profiles, the difference in the results between the various penetration cases is substantial. This stems from the high fixed costs of profiles, which is assumed to be spread over the number of installations. As penetrations rise, the costs of profiles per installation fall away rapidly.

The results of the analysis are presented in values per megawatt-hour of output required for the investment in metering technology to have a positive net present value for the generator. In practice, this output is most likely to be export from the site as generation that is used to offset imports does not require metering to earn a reward and so should not be taken into account in the metering cost-benefit analysis. Alternatively, it could be read as generation if a reward scheme exists that is paid on all generation.

Two additional sets of data may help to interpret the results. First, Table 8 below provides an approximation of how values per unit output translate into implied generator capacities. This table can be used together with the graphs in Figure 8, Figure 10, Figure 11, and Figure 14 to establish the implied capacity of the generator at each level of generation shown in the figures for each technology.

Table 8 – Estimated generator capacities at various scales of output

	PV	Wind/hydro/ CHP (domestic)	CHP (commercial)
Load factor	10%	30%	90%
Generation (MWh/year)	**Implied generator capacity (kW)**		
1	1.1	0.4	0.1
2	2.3	0.8	0.3
3	3.4	1.1	0.4
4	4.6	1.5	0.5
5	5.7	1.9	0.6
10	11	3.8	1.3
20	23	7.6	2.5
30	34	11	3.8
40	46	15	5.1
50	57	19	6.3
100	110	38	13
200	230	76	25
500	570	190	63
1,000	1,100	380	130
5,000	5,700	1,900	630
10,000	11,000	3,800	1,300

Source: ILEX Energy Consulting

Second, some of the results depend critically on the penetration of SSEG. It is interesting to note how these levels of penetration relate to forecasts of market penetration prepared for the Irish market. We have been provided with forecasts for annual installation numbers for small-scale CHP plant, which are shown in Table 9. These suggest that, in the medium term, penetrations are likely to remain low in terms of the assumptions used in the modelling, and costs therefore relatively high.

Table 9 – Forecast penetrations of SSEG in Ireland

No. of installations	**2005**	**2006**	**2007**	**2008**	**2009**
In year					
Domestic CHP	0	5	10	10	10
' New technology' CHP	0	0	2	2	2
Microturbine CHP	8	17	33	50	58
Gas ICE CHP	26	47	62	97	106
Total	**34**	**68**	**107**	**159**	**176**
Cumulative					
Domestic CHP	0	5	15	25	35
'New technology' CHP	0	0	2	4	6
Microturbine CHP	26	73	135	232	338
Gas ICE CHP	8	25	58	108	167
Total	**34**	**103**	**210**	**369**	**545**

Source: Sustainable Energy Ireland

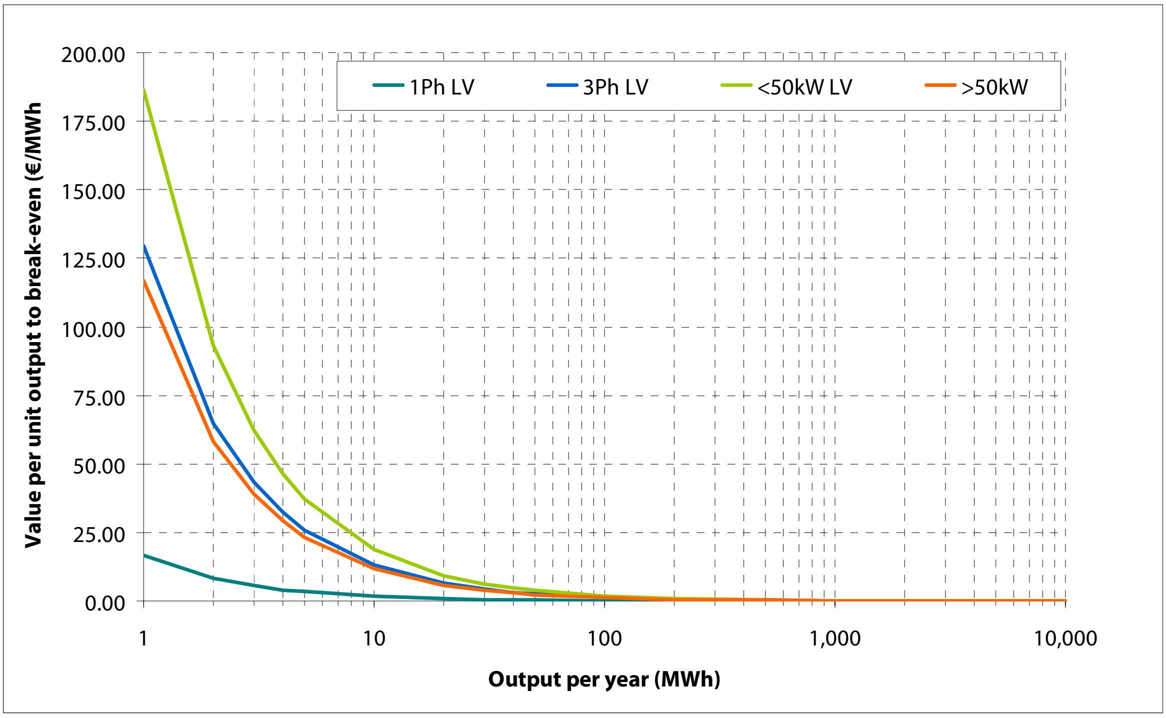
3.2.1. Results for not metering solution

Under this analysis, any reward at any level of output would be positive for the generator as no costs are involved. Clearly, this is a simplified view. Such a solution would entail some bureaucratic costs for the generator and costs for whichever party was charged with administering the reward scheme: presumably at least the government. However, in the absence of such a scheme at present, these costs have not been quantified.

3.2.2. Results for NQH IEG metering without profiles solution

The results from NQH IEG metering without profiles show the required payment per unit output falling rapidly at all scales. At a domestic scale, even with an output of 1MWh per year, the reward required to break even is only €16.54 per megawatt-hour at a penetration of 500 installations. At larger scales of generator or at higher voltage levels, the greater costs of the metering solution result in higher required rewards, but these are still fairly low at realistic levels of output. As a rough guide, the CER's Best New Entrant Price is proposed to be set at €72.86/MWh for 2006. The payment required by all of the solutions falls below this level at a generation of 2.6MWh per year. The results of the analysis are shown in Figure 8. See Table 8 for how these translate into capacities for each technology.

Figure 8 – Rewards required for NQH IEG metering without profiles at low penetrations



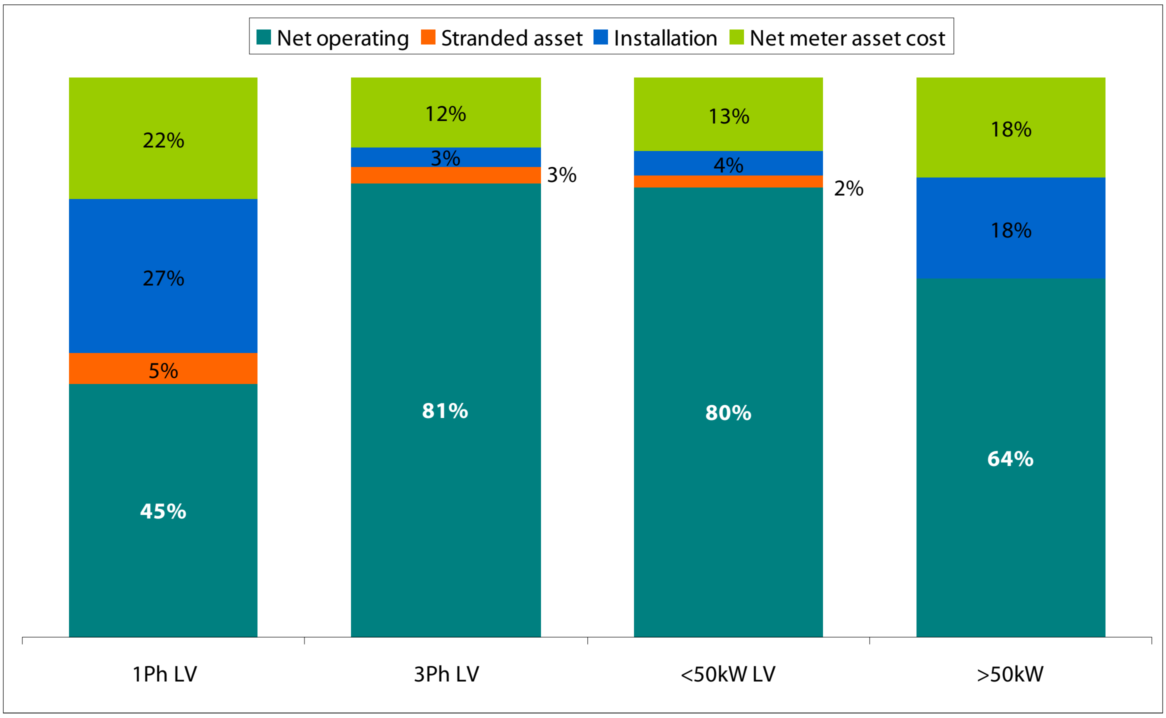
Source: ILEX Energy Consulting

NQH IEG metering without profiles is the simplest metering solution and entails the lowest cost. As a consequence, one of the most important findings is the level of generation at which metering of any kind, in the absence special reward mechanisms or other kind of subsidy, becomes appropriate. From the results, it looks as though NQH IEG metering without profiles could be appropriate at a domestic scale, depending on how much of each generator's output it is able to sell or otherwise earn a reward for that requires metering.

As for not metering, this solution would inevitably entail bureaucratic costs for whichever body was charged with collecting and recording the meter data and paying generators on the basis of this data. Such costs have not been included as they are difficult to quantify. However, evidence from other markets suggests that such costs can be material for generators at the smallest scales considered in this study.

The relative importance of the costs considered in the modelling reveals that the most important costs to generators are the operating costs of the meter. Were these to be borne by another party, the economics for generators of installing this metering solution would be substantially improved. This is shown in Figure 9. Note that in this chart, "net" operating cost means the operating cost of the new meter net of the operating cost of the demand meter assumed to have been at the site before. The "net" meter asset cost is the cost of the new meter net of the present value of any benefits to the DSO of not having to replace the assumed demand meter.

Figure 9 – Relative importance of metering costs for NQH IEG metering without profiles



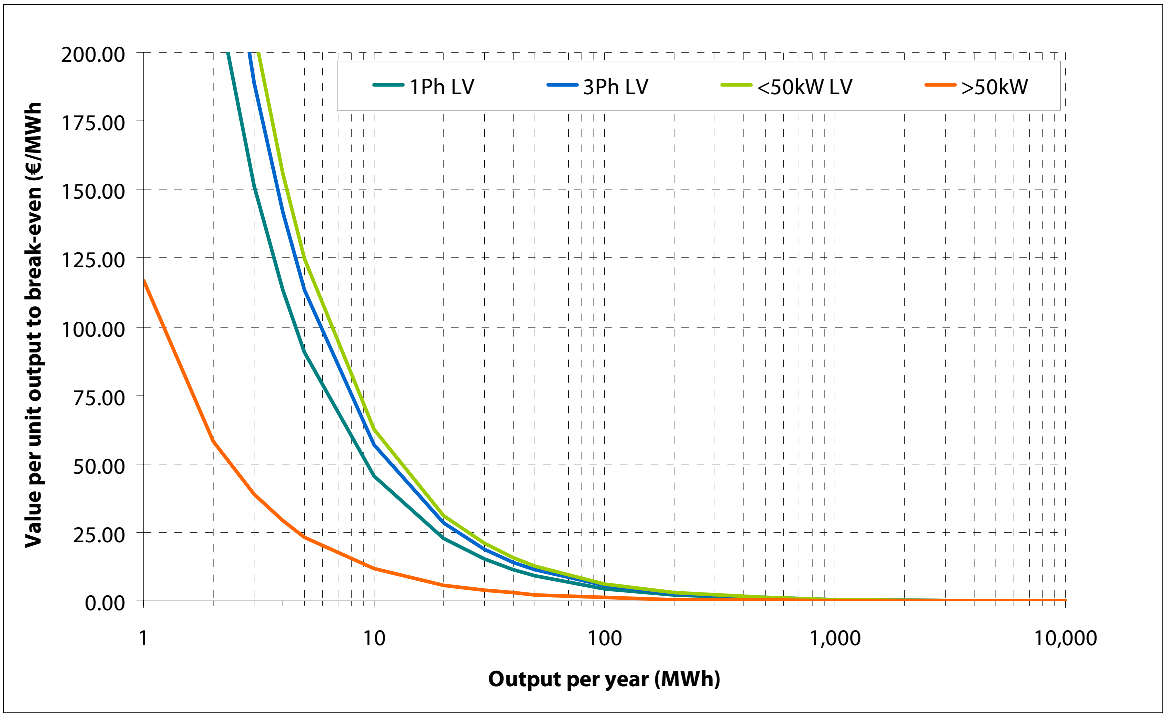
Source: ILEX Energy Consulting

3.2.3. Results for NQH IEG metering with profiles solution

As for NQH IEG metering without profiles, the payments required under NQH IEG metering with profiles fall rapidly with generator output. However, the costs of this solution are considerably higher, particularly for those generators that a non-quarter-hourly metering solution might most be intended to assist and at low penetrations, when they might most need it. Costs for generators with a capacity of below 50kW are much higher than those above 50kW, reflecting the need to replace the existing meter and to create technology-specific profiles. In addition, costs at low penetrations are much higher than costs at high penetrations. This result is driven by the high fixed costs of creating and maintaining profiles, which must be spread over the number of generators using each profile.

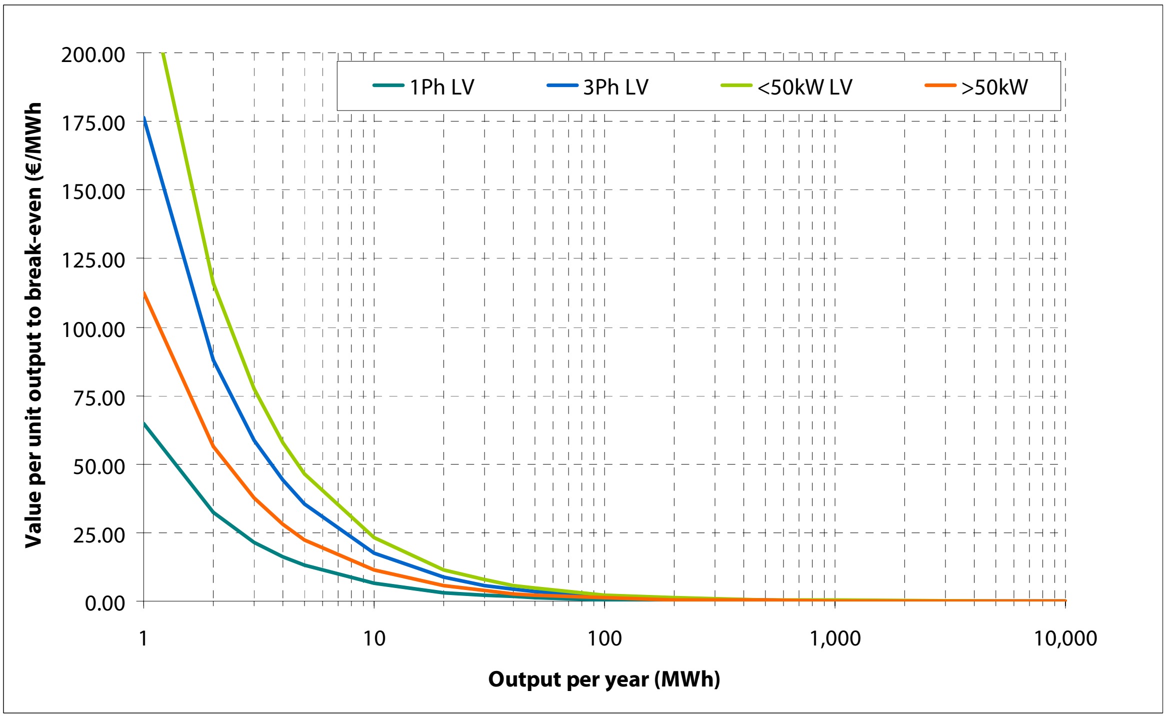
The required rewards at each scale for NQH IEG metering with profiles are shown below. Figure 10 shows the results at low penetrations (500 installations) and Figure 11 at high penetrations (10,000 installations). As an example, at a domestic scale, for a generator with an output of 2MWh per year, at low penetrations the payment required is €226.97 per MWh, whereas at high penetrations it falls to €32.31 per MWh. See Table 8 for how these outputs translate into capacities for each technology.

Figure 10 – Rewards required for NQH IEG metering with profiles at low penetrations



Source: ILEX Energy Consulting

Figure 11 – Rewards required for NQH IEG metering with profiles at high penetrations

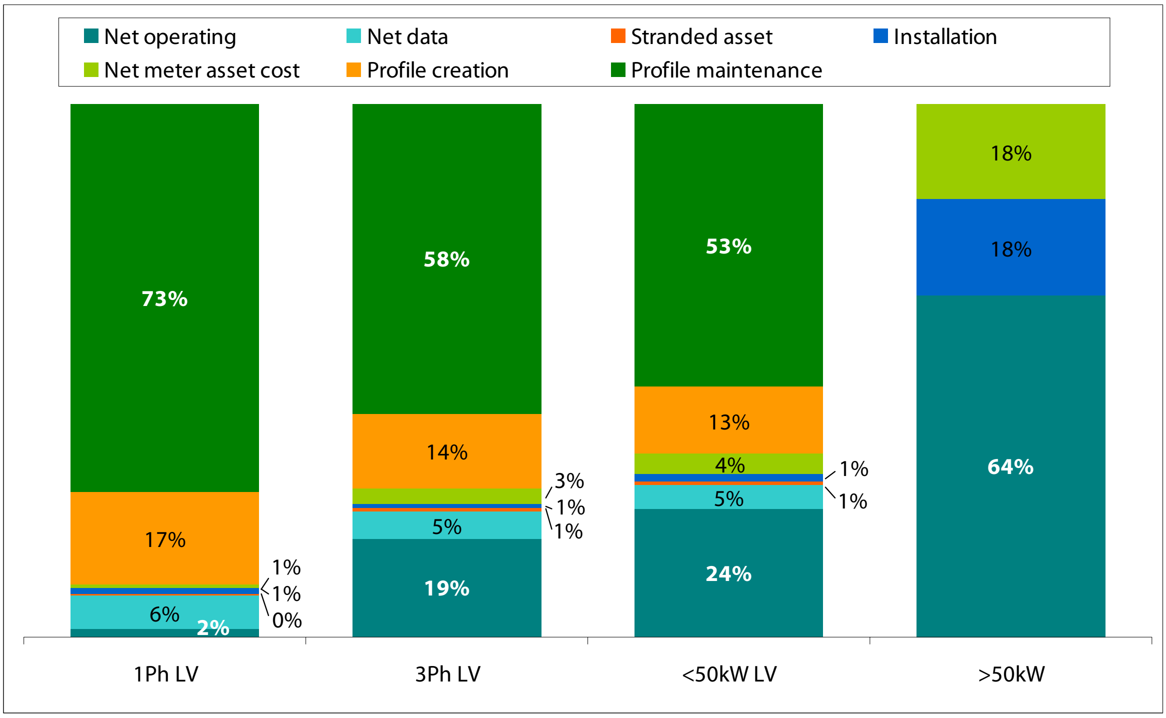


Source: ILEX Energy Consulting

The results suggest that, at low penetrations, assuming that generators bear the costs of profiling, profiles may not be an effective solution for ensuring that small generators are able to receive payment for their export. Exactly where these profile costs become less important is dependent on both the generator's level of output and penetrations. However, it is clear that, absent some kind of subsidy or forced apportionment of the costs of profiles to other parties, at least in the medium term, this solution is likely to be prohibitively expensive for generators at the smaller end of the range in this study.

Figure 12 below shows the relative importance of each of the costs in present value terms to these results at each scale at low penetrations. Note that "net" data costs are the costs of data collection, aggregation and settlement of the new metering arrangement, net of the costs associated with the demand meter that is assumed to have previously been in place.

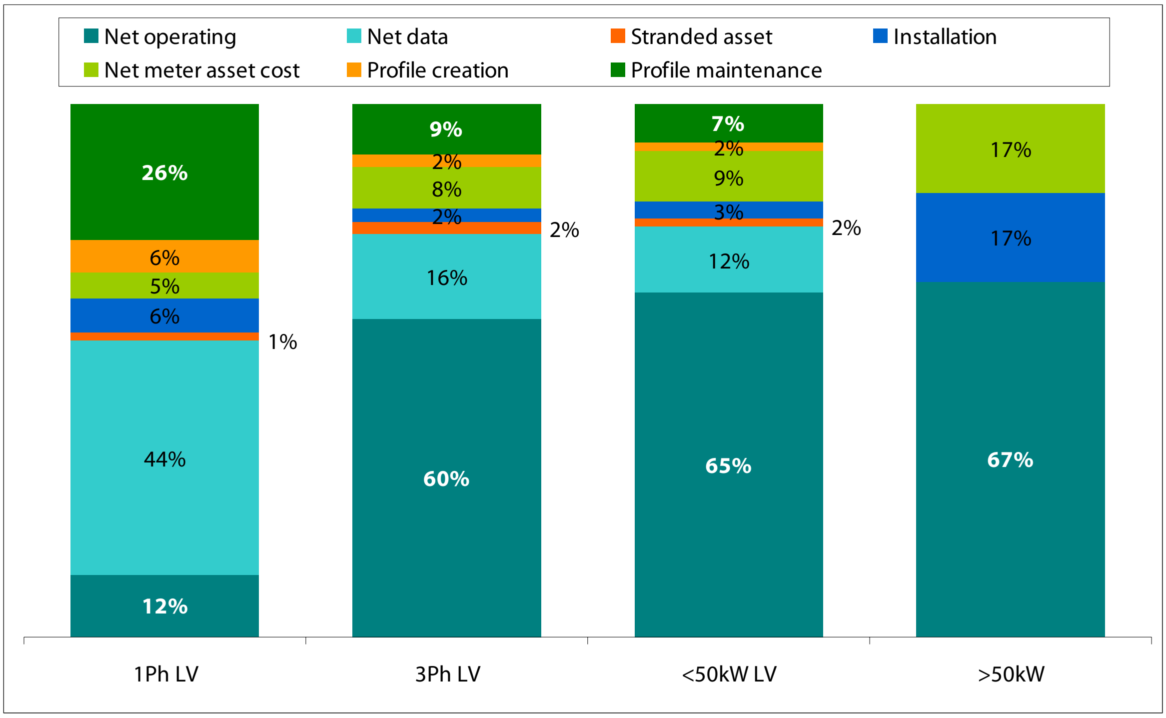
Figure 12 – Relative importance of costs at low penetrations in PV terms for NQH IEG metering with profiles



Source: ILEX Energy Consulting

Figure 13 shows the importance of each of the costs at high penetrations. Together, Figure 12 and Figure 13 show the influence of increasing penetrations on per-installation profiling costs and also how important such annual costs are, in present value terms, to the overall economics of the metering and payment solution.

Figure 13 – Relative importance of costs at high penetrations in PV terms for NQH IEG metering with profiles



Source: ILEX Energy Consulting

In the results above, the costs that have been assumed to be borne directly by the generator could be allocated in numerous other ways. One alternative scenario is that the generator bears the one-off costs of the meter and its ongoing operating costs, but the extra costs of data collection, aggregation and settlement – including the costs of creating and maintaining profiles – are absorbed by the parties responsible. In this case the costs would either be borne ultimately by the government and therefore taxpayers or, more likely, by all electricity consumers. If this were the case, the results for the generator for NQH IEG metering with profiles would be identical to those for NQH IEG metering without profiles.

In this scenario, if the costs not borne by the generator were smeared over all service delivery/connection points (each having a unique Meter Point Reference Number or MPRN) in Ireland, the impact on individual consumers would be limited at low penetrations, although possibly material at high penetrations. Table 10 shows these costs.

Table 10 – Data costs to consumers per MPRN at various SSEG penetrations for NQH IEG metering with profiles

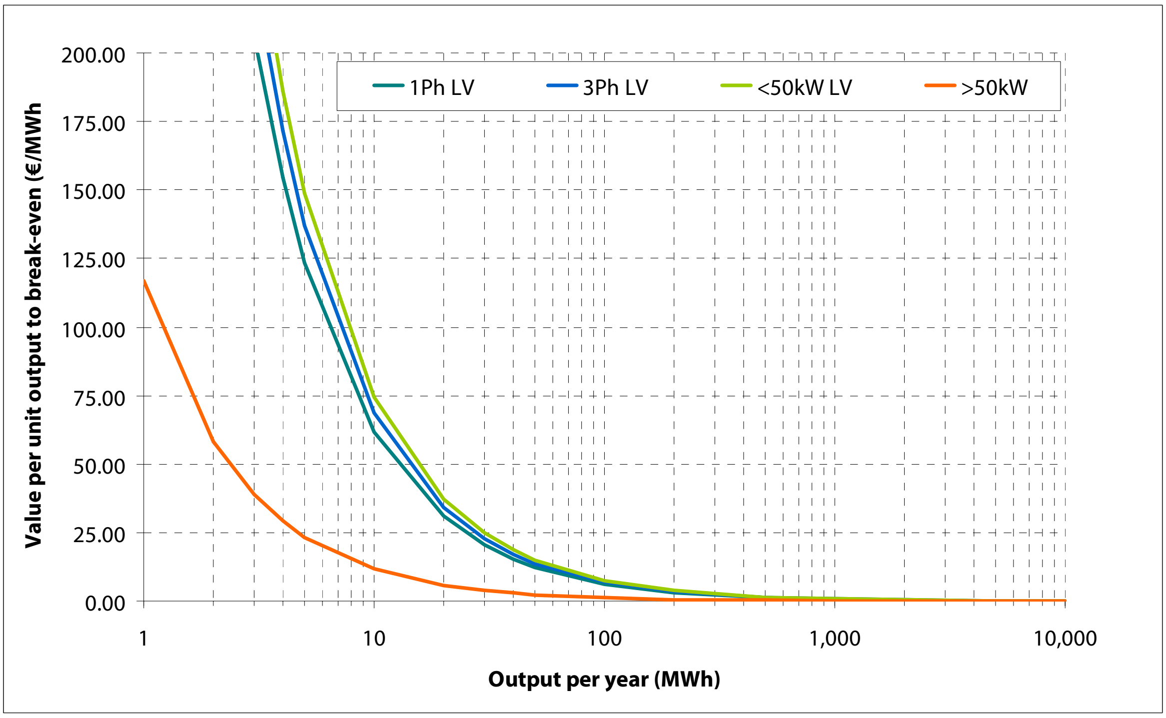
€	Scale			
Installations	1Ph LV	3Ph LV	<50kW LV	>50kW
Total costs				
500	179,250	179,250	179,250	0
10,000	3,585,000	3,585,000	3,585,000	0
Cost per MPRN				
500	0.09	0.09	0.09	0.00
10,000	1.74	1.74	1.74	0.00

Source: ILEX Energy Consulting

3.2.4. Results for QH IEG metering

For the interval metering solution, the costs at the largest scale are identical to those in the non-quarter-hourly metering solutions as the metering and payment arrangements are assumed to be the same. At the three smaller scales, the costs are high for smaller generators, roughly equivalent to the costs of NQH IEG metering with profiles in the low penetration case. The costs fall similarly steeply with generator output. At worst, for a three-phase generator of less than 50kW output, the payment required per megawatt-hour of output to break even falls from €148.90 for an annual output of 5MWh to €37.23 at 20MWh and €14.89 at 50MWh. See Table 8 for how these outputs translate into capacities for each technology.

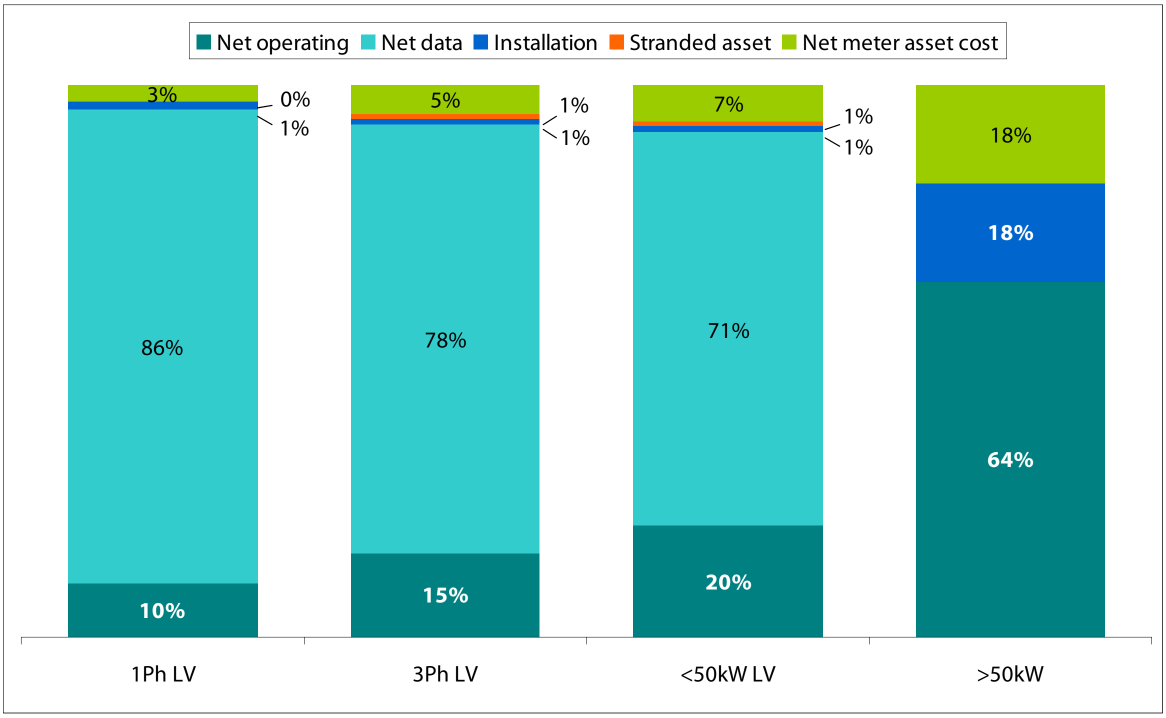
Figure 14 – Rewards required for QH IEG metering



Source: ILEX Energy Consulting

Under QH IEG metering, the costs are dominated by the costs of handling the data, which in turn are dominated by the price of the communications link so that the data can be settled in the appropriate time-frame. The cost of the meter asset itself, and its installation, are relatively small in comparison, as shown in Figure 15.

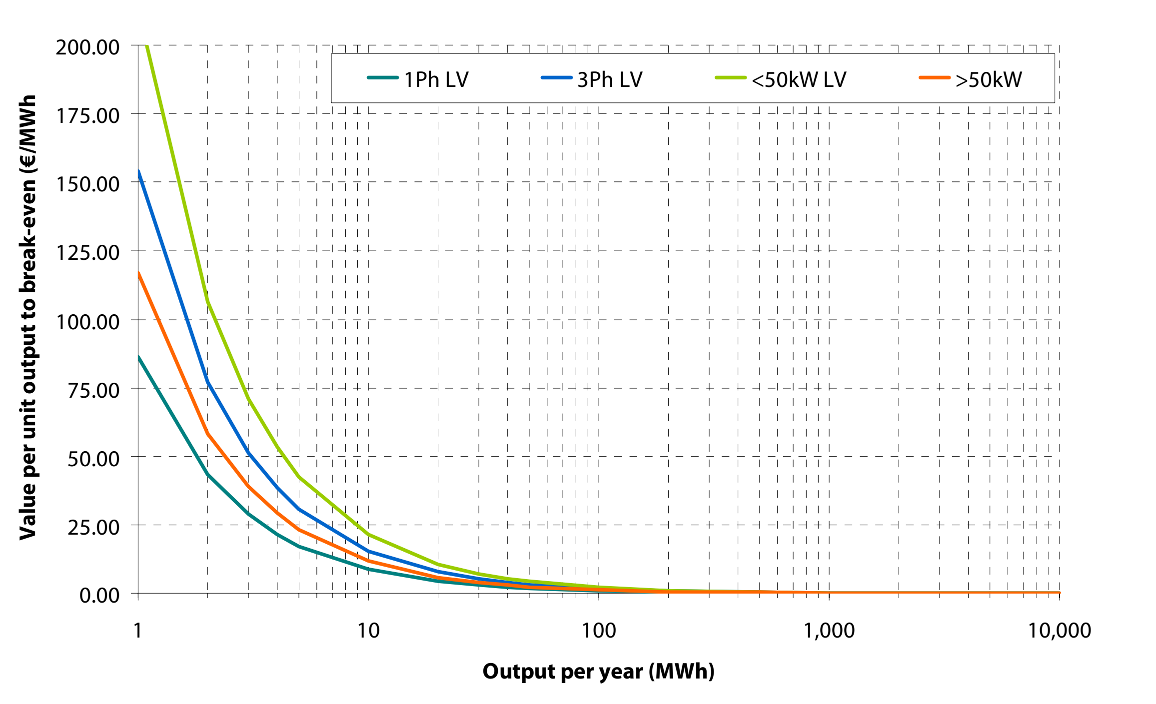
Figure 15 – Relative importance of costs in PV terms for QH IEG metering



Source: ILEX Energy Consulting

As with all of the solutions, it is possible that the costs involved may be allocated to parties other than the generator, improving the generator's economics but imposing costs ultimately on consumers or taxpayers. Assuming, as for NQH IEG metering with profiles, that the costs of data collection, aggregation and settlement were borne by other parties, the economics of QH IEG metering for the generator would be considerably improved at smaller scales. This impact is shown in Figure 16.

Figure 16 – Rewards required for QH IEG metering if data costs not passed to generator



Source: ILEX Energy Consulting

If the data costs for this solution were to be borne by consumers, the impact per MPRN would be low at low penetrations, but becoming more material at high penetrations, as shown in Table 11.

Table 11 – Data costs to consumers per MPRN at various SSEG penetrations for QH IEG metering

€	Scale			
Installations	**1Ph LV**	**3Ph LV**	**<50kW LV**	**>50kW**
Total costs				
500	265,750	265,750	265,750	0
10,000	5,315,000	5,315,000	5,315,000	0
Cost per MPRN				
500	0.13	0.13	0.13	0.00
10,000	2.59	2.59	2.59	0.00

Source: ILEX Energy Consulting

3.3. Costs and benefits for other parties

The metering, settlement and/or payment of SSEG will inevitably incur costs not included in the analysis for many parties. For generators, the bureaucratic procedures associated with claiming any form of payment for their output will require at least time that has an opportunity cost. It is therefore desirable to simplify these procedures to the extent possible.

For suppliers, SSEG that require payment, either under a mandated tariff or on market terms, will entail the bureaucratic costs of customer registration and billing/payment and will bring greater costs than demand customers when they switch suppliers. In addition, suppliers may need to upgrade their customer management and billing systems to handle payments to customers.

SSEG that either spills its output onto the network or is metered non-quarter-hourly and settled on profiles will introduce inaccuracies into the settlement system. The exact nature of these inaccuracies and their costs or benefits to individual suppliers is extremely difficult to quantify. However, the proposed design of the SEM, which is based around a mandatory pool, should reduce the financial consequences of these inaccuracies by providing a single price for energy at any given time. Any financial consequences are ultimately likely to be passed through to the supplier's customer base.

For the DSO and TSO, the type of metering and settlement will have a limited impact beyond enabling them to understand better the energy flows across the network and charge for network provision and use appropriately. Where there is no metering, or it does not reflect the true energy flows accurately, these costs will be inaccurately allocated. However, as for suppliers, it is extremely difficult to analyse either the magnitude of these costs or the extent to which they would fall on individual parties.

In addition to these metering-related costs, small-scale generation will bring other costs and benefits.

SSEG generating to serve an on-site load will reduce demand from suppliers. As a result, they may be forced to raise unit energy prices in order to maintain their margins on lower volumes. These costs are likely to be spread across all customers, to a degree, although there will be an incentive for suppliers to raise prices for demand and/or reduce any price paid for export from embedded generators as this would recoup these costs from their source and disincentivise further installations of embedded generation. In an environment where the government is aiming to support embedded generation, this incentive needs to be carefully managed.

For the DSO, new connections of embedded generators inevitably entail bureaucratic costs and, aside from the smallest generators in this study, will require increased capacity to handle greater numbers of network studies to assess the network's ability to support embedded generators and a greater volume of network changes or upgrades. At present, the costs of such works are recovered directly from generators.

The DSO may also be concerned about the ability to recover costs on their assets serving customers who have now installed generation. This may cause them to change the recovery mechanism from a unit or kilowatt-hour basis to a maximum demand or kilowatt charge. This will clearly affect the commercial case when a customer considers installing generation.

On the other hand, embedded generators may allow the DSO to avoid or defer costs of upgrading its network. Under current arrangements, these savings, which are likely to be more difficult to quantify, would not be passed to the generator(s) responsible. Instead, the savings are likely to be reflected in lower DUoS charges to all customers. This is unlikely to be fair to small generators, who will not be fully rewarded for the benefit they bring.

At higher penetrations of SSEG, the DSO will see reduced energy flows across its network as distributed generation replaces power delivered via the transmission grid. It may then need to adjust its charging structures to accommodate this change and to ensure that its costs of building, operating and maintaining the network are fairly recovered from network users.

As for the DSO, at higher penetrations of SSEG, the TSO will begin to see lower flows of energy across its network, at least as a proportion of total demand. If flows reduce in absolute terms, it, too, may need to adjust its charging structures.

Operation of the system is unlikely to be substantially directly affected by generation of the type and size concentrated on in this study. Relatively few generators of below 1MW capacity are likely to participate directly in the market, owing to the costs and other requirements of doing so. Instead, they are more likely to sell their output to suppliers. As a result, the system operator will see them only through the effect they have on suppliers.

High penetrations of such generation, particularly plant that generates at times of high demand, such as some CHP, could lower the costs of system operation by flattening the overall load profile. However, this needs to be set against the effect of increased generation by intermittent sources, such as wind and PV which, although dispersed and aggregated, are still likely to increase the costs of balancing and ancillary services.

Increased renewable and CHP SSEG will have an effect due to the EU ETS. Depending on the way carbon allowances are allocated under future phases of EU ETS, it is possible that small (<20MW in Phase 1 of the scheme) generation, like renewable generation, could reduce the need for fossil fuel plant operation. This would likely reduce electricity prices that might, in turn, reduce the financial viability of embedded generation, but would also reduce the costs of energy to consumers.

Finally, renewable and CHP SSEG would bring other benefits that do not have a market value. These include security of supply and environmental benefits.

3.4. Conclusions

The numerical results of the cost-benefit analysis are indicative of the level of output at which each solution might be appropriate. However, the analysis reveals the minimum rewards required for each metering and payment solution to be viable. As such, in recommending appropriate scales for the application of each solution, it is important to be certain that the payments available at each scale could not, conceivably, fall below the level indicated. If they were to do so, the metering solution could become financially unviable for some generators or will require financial support from others. This is particularly important at the smallest scales because, as can be seen in the graphs above, costs fall away rapidly with generator output.

Generators' ability to recoup the full costs incurred will depend on a number of variable and uncertain factors, including wholesale energy prices, how they sell their output, use of system and other charging and the type of support mechanism in place, if any. In order to overcome these uncertainties and to be able to recommend appropriate scales for each solution, the study assumes, as is currently the case in Ireland, that the rewards on which generators will base their metering decisions are earned on exports.

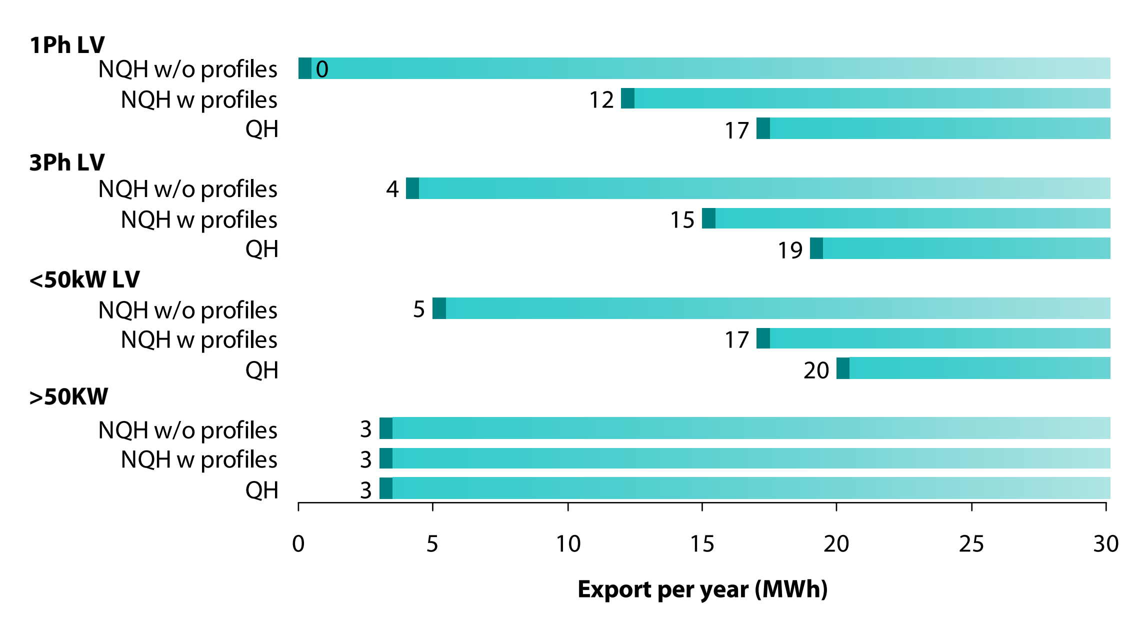
For simplicity, we assume that exports are paid at half of the proposed new entrant price for 2006: €36.43 per MWh (this compares with a current minimum spill price of €28 per MWh). This value is low relative to anecdotal evidence of the commercial terms offered to generators at the larger end of the scale in this study in the market at present, but for the reasons outlined above, it is important that this analysis be conservative. At this price, each of the four solutions would become viable at each of the four scales studied as shown in Figure 17. The scale on the graph does not extend very far: metering costs are only an issue at the smallest scales of generation discussed in this study.

As an example of how to read the graph, at a domestic scale, with a single phase generator connected alongside single phase demand, NQH IEG metering without profiles becomes viable from very low levels of export (although bureaucratic costs, which have not been included in the analysis, may affect this result), NQH IEG metering with profiles becomes viable for generators with an export of 12MWh per year or more, and QH IEG metering is viable for generators with an export of 17MWh per year or more. NQH IEG metering with profiles is shown assuming a low penetration of 500 SSEG units in total.

The results at the largest scale (a generator with a capacity greater than 50kW and CT-operated metering) merely imply that any of the solutions would be appropriate as they all become economically viable at an output of 3MWh per year, although a 50kW generator is likely to export far more than this.

In addition, not metering, which has not been shown, is viable at all scales as it entails no direct quantifiable costs, although, as for NQH IEG metering without profiles, bureaucratic costs have been excluded from the analysis and may be significant for generators at the smallest scale.

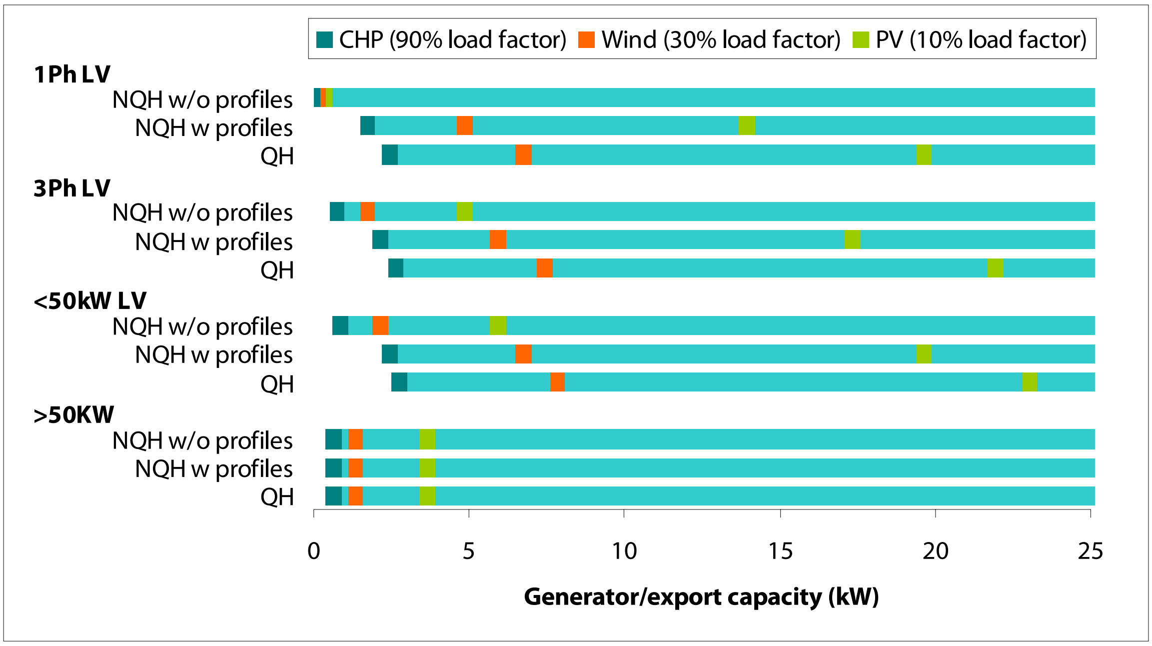
Figure 17 – Applicability range for IEG solutions analysed



Source: ILEX Energy Consulting

It is useful here to cross-reference these results with Table 8, which gives an indication of how levels of output in megawatt-hour terms can be converted into generator capacities given a load factor. The conversions for various technologies are shown in Figure 18. Note that these capacities are appropriate only if either all generation is assumed to be exported to the network (i.e. none of it is used to offset imports) or if they are thought of as the portion of a generator's capacity that exports.

Figure 18 – Applicability thresholds in capacity terms by technology



Source: ILEX Energy Consulting

From the graph it can be seen that, in very approximate terms:

- Not metering is appropriate at all scales of generator.
- NQH IEG metering without profiles, which becomes viable for generators with an output of 1-5 MWh per year, is appropriate for PV systems of 6kW capacity and up and other small renewable and CHP technologies of 2kW capacity and up. Commercial CHP systems would anyway be larger than this minimum size. Considering that the smallest generators are likely to be single-phase where applicability extends down to very low outputs, NQH IEG metering without profiles appears to be appropriate, in practice, at even the smallest scale.
- NQH IEG metering with profiles (assuming a penetration of 500 units), which becomes viable for generators with an output of 12-17 MWh per year, is appropriate for PV systems with a capacity of approximately 19kW and up and other small renewable and CHP technologies of greater than 7kW. For CHP plant with a high load factor, it could be viable for capacities as low as 2kW.
- QH IEG metering, which becomes viable for generators with an output of 17 to 20 MWh per year, is appropriate for a similar range of sizes to NQH IEG metering with profiles at low penetrations.

These thresholds are determined by the highest capacity, at any scale, that each metering solution becomes appropriate for each technology. For example, NQH IEG metering without profiles becomes economically viable for PV at a capacity of approximately 0kW at the smallest scale, approximately 5kW for a polyphase low voltage customer with a single-phase generator, approximately 6kW for a polyphase low voltage customer with a polyphase generator and approximately 4kW at the largest scale (accepting that the largest scale is defined to include only generators larger than 50kW). As a result, unless the metering solution were to be differentiated by scale, then 6kW (the highest capacity at which this metering solution becomes viable for PV at any scale) is the lowest threshold at which this metering arrangement could be put in place without being economically unviable for some PV generators at some scales.

The lack of difference at low penetrations between NQH IEG metering with profiles and QH IEG metering should not disguise differences at high penetrations, where the high fixed costs of profiling under NQH IEG metering with profiles reduce rapidly as penetrations increase whereas costs under QH IEG metering remain relatively high. Only in the case where high levels of quarter-hourly metering became the norm would QH IEG metering's costs fall substantially. Estimates in the England and Wales market suggested that costs "using new technology in the domestic market on a large scale" could fall to a fraction of current levels[6]. Which solution is preferable will depend ultimately on balancing the superior 'fairness' of QH IEG metering against how costs fall in practice, expected penetrations and whether the assumptions used in this modelling hold true. In particular, it may be possible to use cheaper, if less accurate, profiles than those assumed in this analysis.

In order to understand these results better, it is useful to note that the level of exports, although depending heavily on site-specific circumstances, tends to vary with the generator type. At the small end of the scale, evidence from field trials in GB and Northern Ireland suggests that domestic PV installations typically export 45-50% of their generation. Similar trials of domestic CHP units reveal that about one-third to one-half of their generation is typically exported. At a larger scale, anecdotal evidence suggests that the majority of commercial CHP plant in Ireland are sized to meet on-site heat loads rather than to export, resulting in very low proportions of generation exported.

Overall, the results suggest that for the smallest generators (at a domestic scale) either not metering or NQH IEG metering without profiles would be an appropriate solution. Both require the presence of some type of government-funded or mandated reward mechanism as the lack of a specific mechanism to settle generators' output under these solutions means that such output is almost certain to have no commercial value to suppliers. In addition, both of them entail bureaucratic costs that are uncertain and have not been factored into the analysis. At the smallest scales and at low penetrations, these costs will have a significant impact on the viability of these solutions if generators are asked to bear the full costs.

Which of these solutions is preferred and whether a generation meter is required will depend on the non-commercial factors discussed in the following section. However, not metering could be implemented quickly, particularly if an appropriate feed-in tariff were already in place. NQH IEG metering without profiles would require more time, but would provide better quality data and would allow greater future flexibility, even keeping open the possibility of implementing NQH IEG metering with profiles for smaller generators if SSEG penetrations rise substantially or profiling costs fall well below the estimates used in this study.

For the largest generators in the study, quarter-hourly metering will inevitably be the preferred solution because of its superior accuracy and flexibility and because, at this scale, the costs of metering are immaterial relative to the rewards available.

The most difficult assessment to be made is which solution should be used for generators above a domestic scale, but below that at which quarter-hourly metering is the preferred solution. The study shows that it would be possible either to use whichever solution was chosen for the smallest-scale generators up to the threshold for quarter-hourly metering or to implement a third solution for generators at this intermediate scale. Such a third solution would have the significant disadvantage of added administrative complexity, but would offer an intermediate level of accuracy and cost that may be justified. In practice, if not metering was used at a domestic scale, the intermediate solution could be NQH IEG metering either with or without profiles. If NQH IEG metering without profiles was

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[6] Reference: New Metering Technology Working Group (2002) *Interim Report*

used at the smallest scale, then the only logical intermediate solution would be to use the same metering, but with profiles for generators beyond a certain threshold. This would retain the future flexibility to change the future threshold for meters without requiring a change of metering in the installed base.

For a discussion of potential scale thresholds, see section 4.

3.5. Other considerations

The cost-benefit analysis indicates that at least one of the solutions chosen for the study is appropriate at each of the scales under consideration. However, these options were chosen largely on the ground that they were clearly differentiated in terms of their cost. Other solutions of equivalent cost described in section 2 may still be more appropriate. The aim of this section is to survey the considerations beyond costs and benefits that would guide any decision on appropriate metering solutions for Ireland.

The focus of this study has been generators, for whom, in the absence of regulation, the decision to install metering will be largely driven by commercial considerations. The analysis envisaged generators bearing all of the direct costs of metering themselves. This may be a 'fair' solution in that generators would be investing in metering to earn a reward, leaving little justification for costs to be borne elsewhere. However, in practice it may be simpler and possibly cheaper under some metering solutions for some costs to be borne by all electricity consumers rather than designing mechanisms to allocate costs 'fairly'. In addition, to the extent that the costs of metering are likely to act as a barrier to the development of SSEG, which itself brings wider non-market benefits, then it may be 'fair' to allocate some of the costs of metering to parties other than the generator in order to ensure that the desired growth in installations of small-scale generation is achieved.

In addition to analysing the current costs and benefits, generators are also likely to look forward to potential market changes to ensure that the metering solution they install will not become redundant. An example of this might be a site that installs import-export metering to benefit from a feed-in tariff only to find that the reward mechanism in place later changes to a renewable certificate scheme on all generation for which a generation meter is required.

The interests of other parties in metering and payment solutions for SSEG are less clear and their costs and benefits less susceptible to analysis. However, their concerns may play a deciding role in which solution(s) is preferred.

The Irish Government, the CER, ESB National Grid, ESB Networks and suppliers will all have an interest in the solution chosen and these interests may result in certain solutions being mandated or, alternatively, excluded from consideration. These interests are likely to include, among others:

- accurate visibility of the flows of energy on the network and within the country as a whole;
- coherence with other meter replacement plans;
- future flexibility, particularly the risk of creating an installed base of assets that cannot meet future standards or participate in future reward schemes;
- the requirement to meet obligations imposed by EU Directives;
- any desire to harmonise arrangements with the North or with other jurisdictions; and
- the ability of existing systems to cope with SSEG.

Ultimately, concern, or the lack of it, about these issues may drive any requirement on generators to install a metering solution other than the one that provides them with the most economically favourable outcome and the allocation of costs resulting from such a solution.

4. SCALE LIMITS FOR METERING AND PAYMENT

Separating customers with small-scale embedded generation (SSEG) or small-scale generators themselves into generic bands provides clarity and simplifies the arrangements for all parties involved in its manufacture, installation, operation and reward. Within each band, the arrangements put in place for SSEG should appropriately balance the costs/risks and benefits for all parties. In addition, it may be helpful if the limits defining the bands in Ireland corresponded with those already in place in other jurisdictions, most notably Northern Ireland and the EU.

This section analyses the potential limits and proposes one that appears to be beneficial in the Irish market, based on the cost-benefit analysis conducted in section 3. Throughout this section, in particular, it should be noted that the 1MW limit on the size of generation considered by this study does not constitute a scale limit in itself.

4.1. Irish market context for scale limits

There are already a considerable number of scale limits in place that may be relevant to the Irish market. These include limits in use in Ireland and potentially relevant limits in use in Northern Ireland and the EU. These limits are used for a broad range of purposes, only some of them directly or indirectly relevant to the metering of SSEG. These purposes include:

- tariffs;
- incentive/reward mechanisms;
- network impact (adequate capacity, need for reinforcement etc.);
- system charging (use of system charges and similar);
- technical standards (equipment, connection standards);
- market participation (option/requirement for market participation, dispatch, ancillary services); and
- other legal purposes

In many cases, these purposes overlap where they affect metering. For example, the type of metering installed may be at once mandated by the DSO based on system limits and influenced by commercial factors such as the desire receive a certain tariff or incentive payment. In this case, the mandatory requirement forms a minimum standard that other considerations will cause the generator to exceed.

Sections 4.1.1 to 4.1.3 provide a brief overview of the potentially relevant limits for Ireland.

4.1.1. Republic of Ireland scale limits

4.1.1.1. Tariffs

For demand, ESB Networks sets the threshold for moving from a kilowatt-hour to a maximum demand tariff for consumption at a maximum import capacity of 50kW. Tariff structures also change between voltage connection levels.

4.1.1.2. Network impact

The DSO may require sites with a demand capacity of greater than 100kVA to have quarter-hourly metering installed.

4.1.1.3. System charging

Distribution use of system charges are quite complex. For generators, the charging structure will depend on whether the site's maximum export capacity (MEC) is greater or less than its maximum import capacity (MIC), the voltage level at which the generator is connected, whether the site is single or dual feed and the site's MIC. The thresholds for the site's MIC are set at 3kW (the lowest level at which a customer falls into the "business" category) and 50kW (above which DUoS charges are based on maximum demand).

The threshold for changes in the way the Public Service Obligation (PSO) Levy is applied is set at a MIC of 30kVA. Above this level, the PSO is charged on the basis of maximum demand.

Embedded generators with a capacity below 10MW do not pay TUoS charges. For demand connected to the distribution system, the threshold for changes in the TUoS charging structure is set at a MIC of 500kW, where the site has quarter-hourly metering.

4.1.1.4. Technical standards

ESB's "Conditions Governing Connection to the Distribution System" sets out standards for the connection of embedded generators. Differences in these standards depend on the voltage level at which the generator is connected. Generators of below 50kW capacity follow a different process for connection and ILEX understands that ESB Networks is currently considering a further simplification for microgenerators – likely to be defined as those with a capacity below 10kW.

4.1.1.5. Market participation

At present, only generation units with a capacity of greater than 10MW are required to be centrally dispatched, although units of greater than 5MW may choose to be dispatched. Under the SEM, the threshold for compulsory market participation will be 5MW.

4.1.1.6. Incentive/reward mechanisms

AER generally has no threshold, although its lowest-bid structure favours projects able to benefit from scale economies. This has been mitigated in the past by holding different auctions for the same technology at different scales (e.g. AER III and VI had separate categories for wind farms of greater and less than 5MW capacity).

Owing to the current move from the AER to a feed-in tariff, there are currently no relevant thresholds for export tariffs in the Republic.

Sites wishing to participate in the Winter Peak Demand Reduction Scheme (WPDRS), a scheme incentivising customers to lower their demand at winter peaks, must have quarter-hourly metering installed. In addition, they will receive payments under the WPDRS through their supplier, which may present problems to the extent that suppliers, who are paid a 5% administration fee, try to capture a greater proportion of these expenses for relatively small demand reductions.

4.1.2. Northern Ireland scale limits

The scale limits that affect small generation in Northern Ireland almost all differ from those in operation in the Republic. The relevant limits in the North are set out below.

4.1.2.1. Tariffs

Generators with a capacity greater than 100kW are allowed to 'wheel' their exports: selling directly to end-customers over the public network without the need for a supply licence. The upper limit to this arrangement is set at 1MW for renewable generators.

4.1.2.2. Network impact

In the North, generators larger than 30kW may be required to have interval metering and those with a capacity greater than 70kW are required to have CT-operated metering.

4.1.2.3. Technical standards (equipment, connection standards)
Northern Ireland uses the same connection standards as the rest of the UK. For microgeneration, the Energy Networks Association standard G83/1 ("The Connection of Small-Scale Embedded Generation (Up to 16 Amps per Phase) in Parallel with Public Low Voltage Distribution Networks") applies, except that the threshold is set at a capacity of 5kW per phase rather than the 16A per phase (3.7kW at single phase, 11.2kW at three phase) in Great Britain. Above this level, a Northern Ireland version of the UK standard G59/1 ("Recommendations for the Connection of Embedded Generating Plant to the Public Electricity Suppliers' Distribution Systems") for generators up to 5kVA connected at up to 20kV applies. G59/1/NI is supported by the Electricity Association Engineering Technical Report 113 (1995), which contains an additional implied break point at a generator size of 150kW.

The power limit of 16A per phase in G83/1 is designed to match the Electricity, Safety, Quality and Continuity Regulations 2002 (a 2005 revision is currently in draft form) and allow connection of such equipment without the prior authorisation of the distribution system operator. The 5kW limit in Northern Ireland is that used in an earlier standard, G77.

4.1.2.4. Market participation
In Northern Ireland, as in the Republic, the thresholds for market participation are outside the scale range of this study. NIE must monitor intermittent generation, such as wind farms, from a capacity of 2MW. Generators greater than 5MW are required to have a SCADA system installed for closer monitoring in real time and those greater than 10MW are required to be dispatchable.

4.1.2.5. Incentive/reward mechanisms
Renewable generators below 100kW in capacity are eligible to receive a renewable spill tariff.

All renewable generators are eligible for Renewables Obligation Certificates (ROCs). Generators with a capacity of below 50kW may measure their generation for the purposes of earning ROCs once a year. Generators larger than this must report their measurements monthly.

All renewable and good-quality (i.e. high efficiency) CHP generators are eligible for Climate Change Levy Exemption Certificates (LECs). The administrative procedures under which LECs can be earned are simplified for generators below 50kW capacity.

4.1.2.6. Other legal purposes
Although Northern Ireland is subject to the UK Electricity Act (2004), it is not subject to Section 82 of the Act, which deals with microgeneration. For the rest of the UK, this section defines microgeneration as that below a threshold electrical output of 50kW or below a thermal output of 45kW.

4.1.3. EU scale limits
Relatively few scale limits apply at the EU level, with member states generally left to define their own limits. However, a number of limits are relevant.

4.1.3.1. Technical standards
A draft CENELEC Standard prEN50438:2004 "Requirements for the Connection of Micro-Cogenerators in Parallel with Public Low-Voltage Distribution Networks" is currently being drafted and will apply to the connection arrangements for SSEG.

4.1.3.2. Other legal purposes
The CHP Directive defines a "micro-cogeneration unit" as that with a maximum capacity of less than 50kW. It similarly describes "small scale cogeneration" as those units with an installed capacity of less than 1MW.

4.1.4. International scale limits
There are a number of standards set by the International Electrotechnical Commission relating to electromagnetic compatibility (EMC) radiation tests that may have a bearing on small generators. These define limits at 16A per phase and 75A per phase. For completeness, they are:

- IEC 61000-3-3:1995: "Electromagnetic Compatibility (EMC) Limits. Limitation of Voltage Changes, Voltage Fluctuations and Flicker in Public Low-Voltage Supply Systems, for Equipment with Rated Current >16 A per Phase and not Subject to Conditional Connection";
- IEC 61000-3-11:2001 "Electromagnetic Compatibility (EMC) Limits. Limitation of Voltage Changes, Voltage Fluctuations and Flicker in Public Low-Voltage Supply Systems, for Equipment with Rated Current <75 A per Phase and Subject to Conditional Connection"; and
- IEC 61000-3-2:2001 "Electromagnetic Compatibility (EMC) Limits. Limits Harmonic Current Emissions (equipment input current up to and including 16 A per phase)".

4.2. Possible criteria for defining scale limits
As can be seen above, the criteria used for defining scale limits in Ireland and other relevant jurisdictions is limited. However, there is a broad range of potentially usable criteria. These fall broadly into two categories: technical standards and commercial arrangements.

Technical standards include the capacity of the generator, the type of metering currently in place (whole current – single or polyphase – or current transformer (CT) operated), the service capacity (in Amps), the connection voltage (HV or LV) and the source of the generation. These criteria are identified in Table 12, numbers 1 to 5.

The other criteria for categorisation are based on some sort of commercial assessment of the customer. This may be the capacity of the generator, the flow of energy (and hence monetary value) or the nature and value of the property in which the generator is installed. These criteria are identified in Table 12, numbers 6 to 12.

Table 12 – Possible criteria for defining scale limits

No.	Criteria for break point	For	Against
1	SSEG installed capacity: • < 16 Amps / phase • < 60/100 Amp / phase • > 100 Amp / phase	Could be used to exempt some smaller installations from metering SSEG.	Difficult to audit and maintain a reliable record of installed capacity.
2	Current metering: • Whole current 60/100 Amp • LV CT operated • HV CT operated	Low-cost option; requires knowledge of characteristics of existing meters. At sites with CT operated metering, cost of additional metering generally insignificant compared with generating equipment.	Provides no indication of SSEG generation.
3	Service capacity: • Single phase 60/100 Amp • Polyphase 60/100 Amp • Polyphase >100 Amp	Easy for distributor to establish.	Provides no indication of SSEG generation, but would give upper limit for each category.
4	Supply voltage (LV/HV)	Easy for distributor or supplier to establish.	Provides no indication of SSEG generation.
5	Source of SSEG (non renewable/renewable/mixed)	Provides full extent of SSEG and energy source.	Source may need to be audited and each type of source individually metered.
6	Tariff (domestic/commercial/ Industrial)	Easy for supplier to establish.	Provides no indication of SSEG generation.
7	Annual consumption	Easy for supplier to establish or estimate.	Provides no indication of SSEG generation.
8	Annual SSEG	Would limit un-metered volume of SSEG.	Difficult to estimate.
9	Annual bill	Easy for supplier to establish or estimate.	Provides no indication of SSEG generation.
10	Standard Industrial Classification (SIC) code.	Could be used to exempt some customers from metering SSEG.	Provides no indication of SSEG generation. Supplier may not have information and would need to categorise each SSEG customer.
11	Size/type of property	As no. 10	As no. 10
12	Rateable value	As no. 10	As no. 10

Source: ILEX Energy Consulting

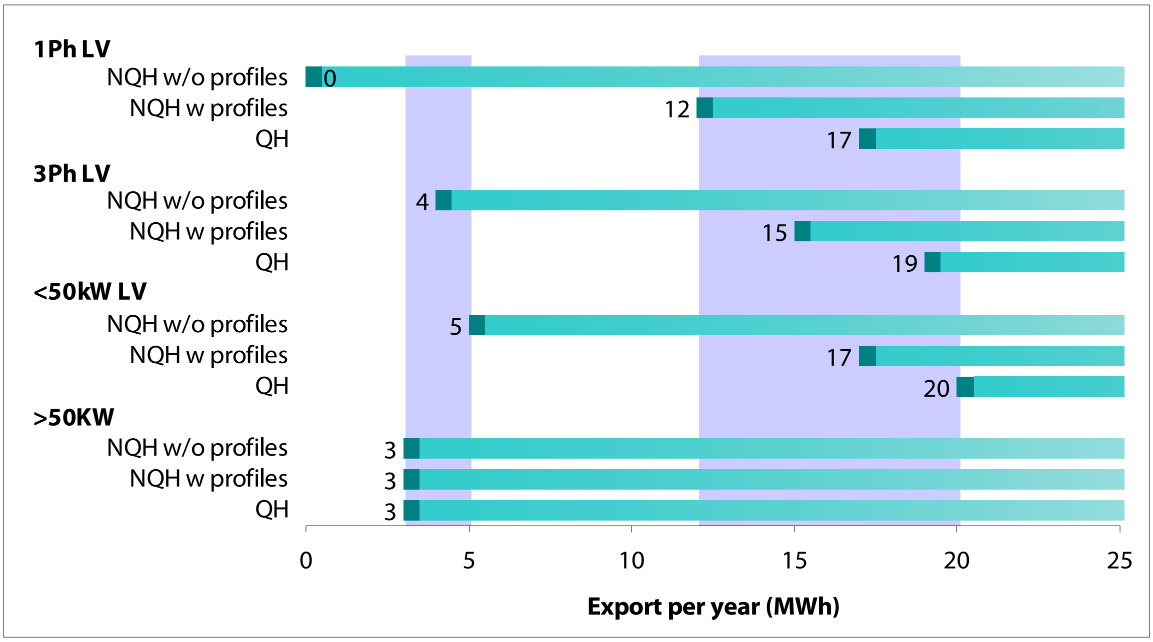
4.3. Suggested limits for metering SSEG in Ireland

As discussed above, the relationship between metering and scale limits is often indirect. As a result, although it would be possible to use just one criterion for assessing whether and how to meter the export/generation of a particular customer, a combination of criteria may also be appropriate. This would allow the decision to take into account not only the nature of the generator, but also other relevant factors such as the nature of the network to which it is connected, the type of metering already on site and any on-site demand that it serves.

There will be two primary sources of information that feed into this decision-making process. Firstly, the information already known by the electricity supplier/distribution network operator and, secondly, information provided by the customer/installer of the generating equipment.

The results of the analysis in section 3.4 show two relatively clear thresholds for the applicability of the various metering and payment options analysed, bearing in mind that the assumed rewards for exports were defined fairly simplistically. One threshold runs from an output of three to five megawatt-hours per year, equating, conservatively, to a generation capacity of three to five kilowatts. The second runs from an output of 12 to 20 MWh per year, equating, approximately, to a capacity of around 20kW. These thresholds are shown in Figure 19.

Figure 19 – Thresholds for metering and payment of SSEG



Source: ILEX Energy Consulting

These values could be used as the basis for thresholds in themselves or could be mapped onto some of the existing thresholds outlined earlier in this section. The most relevant limit appears to occur at 50kW, the EU definition of microgeneration. Although this is considerably above the 20kW threshold suggested by the analysis, it may be appropriate for two reasons:

- thresholds need to take into account the likelihood that only a portion of a generator's output will be exported. For PV, which several studies have shown exporting in the region of 50% of its generation a year, the threshold would need to be doubled to arrive at a realistic threshold for the total installed capacity, rather than the export capacity. For generators whose output is better matched to demand and who therefore export a smaller proportion of their generation this multiple will be higher.

- thresholds should be set high enough that they are highly unlikely to prevent the installation of an appropriate meter or harm the economics of an otherwise viable installation.

The other potentially relevant existing threshold is the threshold for simplified connection of microgeneration used in Northern Ireland, which is set at 5kW for single-phase generators and 15kW for three-phase generators. ILEX understands that ESB Networks is considering introducing a simplified connection process for microgenerators at a capacity of around 10kW. This threshold would also be appropriate for metering. Although using the Northern Ireland thresholds might harmonise practices in the two jurisdictions, applying the NI connection thresholds to metering has the disadvantage that there is limited justification, in economic terms, for applying a different threshold to polyphase generators. As a result, the ESB Networks 10kW threshold may be more appropriate, if it is to be adopted.

It is worth noting that the results of the analysis suggest there is little economic rationale for differentiating the threshold by 'scale' (here used primarily to represent the type of metering already in place). The differences between costs of each of the four solutions tend to be greater than the differences in costs of the same solution at different scales, provided that the assumptions made in this analysis about the technical requirements of metering at each scale hold true. As a result, we do not believe that thresholds based on the type of metering already in place at the site would be appropriate.

The remaining potential criteria for thresholds listed in Table 12 are generally either proxies for scale (connection voltage, service capacity) or largely unrelated to the economics of the metering and payment solution, which depends most directly on the quantity of generation exported, which can be approximately translated into an export capacity and, more tentatively, into the more practical measure of generator capacity. As a result, we believe that generator capacity thresholds are the best proxy on which to base metering thresholds.

One exception from Table 12 is the type of generator. The analysis shows that it would make economic sense to differentiate the threshold by technology, especially for technologies, such as PV, that have reasonably consistent load factors are not controllable. However, such differentiation would add considerably to the complexity of arrangements for SSEG and, as a result, we believe that appropriately conservative thresholds covering all technologies are likely to be a more practical option.

4.4. Potential solutions

The scale limits identified in 4.3, combined with the results presented in section 3.4, suggest four potential solutions around the two thresholds, as shown in Table 13.

Table 13 – Potential metering options

Generator capacity	0 – 10kW	10kW – 50kW	50kW +
Potential Solution A	Not metering	NQH IEG w/o profiles	QH IEG
Potential Solution B	Not metering	NQH IEG w profiles	QH IEG
Potential Solution C	NQH IEG w/o profiles	NQH IEG w/o profiles	QH IEG
Potential Solution D	NQH IEG w/o profiles	NQH IEG w profiles	QH IEG

Source: ILEX Energy Consulting

If not metering is considered unacceptable, then Potential Solution C (in which meters are installed, but no profiling is implemented for generators up to 50kW capacity) would appear to offer a strong combination of speed of implementation, future-proofing (always allowing a later move to Potential

Solution D, for example), accuracy and data availability. However, it would require the presence of a feed-in tariff or similar reward mechanism to be effective.

5. MARKET BARRIERS

In addition to an analysis of metering and payment solutions, the project scope asks ILEX to review the other barriers to the development of small-scale embedded renewable and CHP generation in Ireland. Some of these barriers are common to markets everywhere, while others are specific to the Irish context and to its existing market arrangements. This section provides a brief summary of the barriers to the greater adoption of SSEG in Ireland.

5.1. Commercial barriers

5.1.1. Capital costs

Many small-scale renewable and CHP technologies have higher capital costs per unit output than their more established, non-renewable competitors. This applies particularly to technologies such as solar photovoltaics and fuel cell CHP systems, for which capital costs are multiples of the cheapest technologies. However, cost remains an issue for all of the technologies, even for conventionally fired CHP at the larger end of the scale covered in this study. In this latter case, while the overall economics of installing and operating the CHP system may be compelling, the capital costs are still higher than those of installing a conventional boiler. As a result, in circumstances where capital is constrained or operating costs are less of a concern (in property developments to be leased, for example), CHP may still lose out to technologies that require lower up-front investment.

5.1.2. Public Service Obligation Levy

The design of the Public Service Obligations (PSO) Levy does not reflect the contribution of autoproduction. The PSO Levy is a tax on electricity consumers designed to fund the Alternative Energy Requirement, an auction-based system that effectively subsidises various renewable and CHP generation. The PSO is paid by autoproducers on their MIC, thereby ignoring the contribution of any on-site generation. Given that much of this generation is itself the intended recipient of the subsidy, it seems contradictory to be ignoring its contribution in levying the tax.

5.1.3. Tariffs

Securing appropriate payment for export presents a significant barrier to SSEG in Ireland. Any generator essentially has three options: to become a supplier and participate in the bilateral market, to participate in the market and receive spill prices but not to supply demand directly, or to sell to a supplier.

Becoming a supplier requires obtaining a licence to supply electricity, acceding to the Trading and Settlement Code and obtaining access to the transmission and distribution systems. This process is time-consuming and expensive for smaller generators, as it requires up-front security payments that typically total €25,000. Participating in the market is cheaper (requiring a €5,000 security payment) and simpler, but spill prices are relatively poor. As a result, this is not likely to be a commercially viable option.

Selling to a supplier is a simpler option, but at present in Ireland, only one supplier is offering reasonable prices for export from small CHP or renewable generation. Small generators run the risk that no supplier is interested in purchasing exports at a reasonable price, damaging their commercial viability.

As a result of the poor economics of exporting, CHP autoproducers in Ireland tend to be sized to meet on-site heat loads. For other types of generators in this study, the low level of prices for export may deter investment altogether. Experience in other markets suggests that this problem is particularly acute at the smaller end of the scale in this study, where exported volumes are so small as to fail to attract a tariff from the market at all. This is especially important as studies of domestic-scale renewable generation tend to show that it exports a high proportion of the energy it generates.

5.1.4. Impact of market liberalisation and the SEM

Continued liberalisation of the Irish market and the move to the SEM will both have implications for SSEG. Although these changes might better be described as providing opportunities and threats than presenting barriers, it seems appropriate to discuss them here.

The full liberalisation of the supply market in the Republic in February 2005 has removed the advantage that 'green' suppliers enjoyed by being the only companies other than ESB Customer Supply, the incumbent, allowed to serve customers with a demand of below 100MWh per year. As such, 'green' tariffs must now compete in a fully open market with 'brown' (i.e. non-green) suppliers. The exact effect of this is unknown, but seems likely to be negative for green suppliers in the short term and therefore negative for 'green' generators looking to sell their output to suppliers.

The rules of the SEM are currently in the early stages of development. Nonetheless, some features of the market that will affect renewable and CHP SSEG are already visible. The SEM is set to be based around a gross pool. Such a design will, in some ways, be an improvement for SSEG. Although the number of SSEG within the scope of this study that will be able, technically or financially, to participate in the market is likely to be small, it will enable those that do participate to receive the full market price for their exports. On the downside, the pool will almost certainly increase the volatility of prices, creating greater uncertainty for SSEGs exposed to it. Contracts to hedge price exposure may remain elusive.

It is expected that generators above 5MW will be obliged to participate in the SEM, whereas those below 5MW will have the option to participate directly. The CER and NIAER[7] have suggested that there will be another threshold ("of the order of tens of kW") below which generators would not be given the option of direct participation. Since CHP and renewable generation is entitled to priority dispatch, they should be able to participate either as price-makers (dispatchable generation which bids a price into the market and which will be expected not to generate if its price is out of merit) or as price-takers (non-dispatchable generation which will be entitled to run irrespective of price but will have to accept the prices offered (even if they are negative, which could happen in theory).

An area of particular concern is the extent to which SSEGs will benefit from capacity payments. The current expectation is that the SEM prices will be separated into an energy element (which in turn is expected to be driven by ESB's short-run cost of generation) and a capacity element. Non-SEM participants may not benefit from capacity payments, whereas directly participating intermittent generators may face a diminished credit based on a calculated capacity credit. Given that the average availability of transmission-connected plant was 77% in the year to September 2004[8], the justification for special treatment for intermittent generators will need to be strong.

Although 'green' and CHP generators enjoy special arrangements that shield them from full balancing costs under the current market arrangements in Ireland, the presence of the gross pool under the SEM will stop SSEG being penalised on the spread between top-up and spill prices.

Finally, the very uncertainty over the structure of the SEM may be having a negative effect on the development of SSEG, as on the development of other generation plant.

5.1.5. Connection approval procedures and charging

Currently almost all SSEGs are required to apply to ESB Networks for connection in accordance with the procedure outlined in ESB's guide to the process[9]. Very small generators (below a MEC of 50kW), however, are treated in a manner similar to demand customers. ESB Networks is currently reviewing the connection process for microgenerators[10] with the aim of further streamlining the process while continuing to conform to EN 50438 and ESB Networks' requirements on voltage and frequency control, among others.

Anecdotal evidence suggests that procedures for connecting small-scale generation of greater than the 50kW threshold are somewhat restricting development of the market. Some potential on-site generators are dissuaded by the costs and timeline of the connection process. In order to install embedded generation, generators are recommended to first commission ESB National Grid to

[7] Reference: CER/NIAER (June 2005) *The Single Electricity Market: High-Level Design Decision Paper*

[8] Reference: ESB National Grid (December 2004) *Generation Adequacy Report 2005-2011*

[9] Reference: ESB Networks (February 2002) *Guide to the Process for Connection to the Distribution System*

[10] Generators of below 10kW, approximately, according to ESB Networks' definition

undertake a network study to see if the local network is capable of supporting the proposed generator. The study costs €635 + 13.5% VAT, which must be paid up front, although it is netted from the costs of connection, should this go ahead. ESB estimates that such a study should take approximately "one to three months to complete"[11], but experience suggests that it can take longer. The study sets out the options for connection and may recommend upgrades to the local network, which must be paid for by the generator. The conclusions of the study provide limited transparency. Following the study, if the generator decides to proceed with the installation, ESB Networks does not commit to a delivery date for the upgrade work required and the work itself is not contestable. The CER acknowledges that such contestability is desirable[12], but it is not currently allowed for in legislation. Anecdotal evidence suggests that together, these factors, have acted as a barrier to the installation of SSEG.

Although this barrier is not insurmoutable, elements of the current arrangements are clearly capable of improvement. Firm deadlines for the study and subsequent work, greater transparency in the assessment of the upgrade required and calculation of its costs and a right for the work to be contestable would help significantly.

The situation for renewable embedded generators of greater than 0.5MW capacity may be improved under the new Group Processing Regime, whereby generator applications for connection are considered together and a standardised set of charges apply.

At present, connection charging in the Republic is on a 'deep' basis, so that the full costs of any required network upgrade are borne by the generator. In many circumstances, the benefits of such upgrades may accrue not only to the generator, but to other network users, too. In this case, this cost allocation will not necessarily be fair. Generic rules on cost allocation for network upgrades are perhaps impossible to make truly fair. However, other markets have rules that acknowledge the likelihood that some of the benefits are shared. For example, connection charging in the North (although similarly referred to as 'deep') allocates only the full costs of upgrades at the voltage level of the generator's connection. Upgrades required above this level are smeared across all network users. The SEM may move towards such 'less deep' charging. Certainly, transmission connected charging under the SEM looks likely to be on a 'shallow' basis.

It is worth noting that NIE's SMART programme[13] takes a pre-emptive approach to the problem of rewarding embedded generators for their ability to defer or avoid network reinforcement costs where these are clear by identifying areas where the grid is weak and offering incentives for embedded generation in such locations.

5.2. Technical barriers

5.2.1. Connection standards

At present, all embedded generators of below 5MW in Ireland are subject to the same connection standard, G10, set by the Electro-Technical Council of Ireland. While appropriate for many embedded generators of this scale, such requirements are likely to be unduly onerous, and therefore hinder the installation of, SSEG at the smallest scale. In Northern Ireland, a version of the UK's G83/1 standard applies for generators of up to 5kW in size at single phase and 15kW at three-phase.

5.2.2. Metering standards

As for connection standards, consideration should be given to the adoption or creation of metering standards for Small Scale Embedded Generation for all the measured quantities (demand, generation, import and export).

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[11] Reference: ESB Networks (no date) *Application for Connection to the Distribution System: Generators*

[12] Reference: CER (2005) *Standard Pricing Approach for Connecting Renewable Generators to the Distribution Network*

[13] Reference: http://www.niesmart.co.uk/smart2.htm

Although legislation and standards may exist for demand (consumption) meters, few requirements exist for embedded generation. In general BS EN 61036 and BS EN 60521 standards are adopted for tariff metering. These same standards could be adopted for both generation and export.

Careful consideration needs to be given to the maximum current rating (I_{MAX}) of the generation measuring element. The standards prescribe the accuracy requirements between the limits 100% I_{MAX} and 10% I_b as ±2% at Unity Power Factor. The overall in-service accuracy limits may be slightly wider.

From the above requirements it can be seen that a generator with an output of less than 16 Amps per phase should have an appropriately smaller measuring element (I_{MAX}) of say 25 Amps, so that the recording accuracy is maintained across as wide a range of the operating curve of the generator as possible.

The import/export measuring elements are determined by the maximum load or demand that the customer is likely to impose on the meter. For a whole current meter the maximum current is limited by the supply fuse (cut-out), predominantly 80 Amps in Ireland.

For CT metering, the existing CTs installed at a site may have a variety of accuracy limits. Any new CTs installed should ideally be to BS EN 60044-1:1999 and the ratio closely matched to the maximum current anticipated.

In the case of generators with separate CTs to those used for measuring import and export at the supply terminals (cut-out), the CT ratio should be closely matched to the output of the generator. This may mean adopting smaller ratios (e.g. 50:1) than is normal practice. This will help retain the overall metering accuracy within acceptable limits.

In addition, consideration should be given to the consistent labelling of meters and registers on-site, such that the measured quantity can easily be identified. In this respect, a simple code of practice with clear examples could be produced for all installers to follow.

5.3. Regulatory barriers

5.3.1. Definition of CHP

CHP currently defined in the 1999 Electricity Regulation Act as having an operating efficiency, based on a gross calorific value, of greater than 70%. This definition has the advantage of simplicity. However, it does not reflect the definition of "high-efficiency cogeneration" contained in the CHP Directive and is more onerous than in some European countries. This may be restricting the development of small-scale CHP generation by limiting which the number of plants eligible to receive CHP support measures.

5.3.2. Illegality of private wire networks

In certain circumstances, installation of small-scale embedded generation would be economically viable for a cluster of demand sites if the power could be provided through a private wire network or if unlicensed supply over the distribution network were permitted up to a *de minimis* threshold. However, the 1999 Electricity Regulation Act forbids the use of private wire networks unless ESB has first refused permission for a connection to the network and the CER has given its approval. In addition, it defines a final customer as "a person being supplied with electricity at a single premises for consumption on those premises", thereby ruling out the possibility of power from the grid being supplied to a single point of connection encompassing a cluster of customers.

In the North, unlicensed supply is permitted by generators of between 100kW and an upper limit that varies depending on the type of generation. Below this level, for renewable generators, a single-level feed-in tariff applies.

5.3.3. Incentive scheme uncertainty

As noted earlier in this report, Ireland is in the process of changing its support mechanism for renewables and CHP from an auction-based system, the AER to one based on a feed-in tariff. At present, the details of the feed-in tariff are unknown, including whether there will be volume limitations. In addition, the presence of the UK Renewables Obligation green certificate scheme in Northern Ireland and various moves towards the creation of an EU-wide renewable energy certificate trading scheme, possibly based on the guarantees of origin mandated by the Renewables Directive, open the potential for Ireland to move towards developing a green certificate scheme at some point in the future. Whether this might include CHP is also uncertain.

Anecdotal evidence suggests that this considerable uncertainty over Ireland's future support mechanism is having a doubly negative effect on renewable and CHP generation. This is obviously detrimental to project economics. Second, the apparent promise of or potential for a future support mechanism is causing would-be developers of projects, even where these are economic without a support mechanism, to wait until the situation is clarified before installing for fear of missing out on an additional revenue stream.

In addition, it is worth noting here that, whatever form the final incentive scheme takes, it will be important for generators at the smaller end of the scale that the bureaucratic procedures involved in securing incentive scheme payments are as streamlined as possible, so as not to materially diminish, or even negate, the value of the incentive.

5.4. Other barriers

5.4.1. Installer capacity and expertise

Anecdotal evidence from other markets, notably Northern Ireland, suggests that a lack of installers and installation expertise can have a negative impact on the development of SSEG across a range of technologies. Micro-scale CHP (1-2kW) is particularly sensitive to such issues as installation requires both electrical and gas fitting qualifications, which few people possess. However, growth of other technologies, including PV is also understood to have restrained on the island by a lack of qualified installers.

In the North, this problem has been partly overcome by generous capital grants, which helped to bring installers into the market and by a programme of awareness building and training run by Action Renewables (a joint venture between the Department of Enterprise Trade and Investment and Viridian) to help develop an indigenous industry in these technologies.

5.4.2. Awareness

Small-scale embedded generation is often provided by relatively new technologies and is, at present, relatively uncommon in Ireland. The combination of these factors means that potential users of SSEG may not be aware of its potential. This is a circular effect, with limited market penetrations leading to low awareness and low awareness contributing to limited penetrations. In other jurisdictions, government-sponsored promotional campaigns, support mechanisms, purchasing programmes and targets, among others, have been used to overcome this cycle.

6. AREAS FOR FURTHER WORK

Given the limited consideration given to SSEG to date in Ireland, particularly at the smaller end of the scale, much work remains to be done in analysing appropriate arrangements to enable SSEG to compete equably in the market. The additional work proposed in this section addresses the key issues.

6.1. Tariffs

The ability of small-scale embedded generators to receive payment for their exports can be critical to their economic viability, as this study implicitly acknowledges. A further study could usefully analyse the level of payment that such generators were able to receive in practice through various routes. Such a study could similarly investigate the level of payment required in order for various SSEG technologies to be financially viable at various scales. The latter would be particularly important in the design of a feed-in tariff.

6.2. Connection standards and arrangements

Connection standards and procedures in the Republic are currently burdensome, particularly for very small generators. These will remain a major barrier to the penetration of small-scale embedded generation unless they can be simplified to a degree appropriate to the impact that such generators will have on the DSO and interested parties. A study would outline the issues at stake, review how common concerns had been overcome in other markets and suggest appropriate scales at which alternative arrangements might be put in place.

6.3. The Single Electricity Market

The SEM will affect small generators, and the interaction between regulations in the Republic and the North, in numerous ways. As the outline of the SEM becomes clearer, a study could analyse its likely effects and propose alternatives where appropriate. It could also look at the potential for differences in the rules between the two markets to create problems or present opportunities for SSEG.

ANNEX A– CHUNKED PROFILING PROCESS IN GB

SSEGs in Great Britain still have the option not to meter their export and, instead, to continue spilling onto the network. As such, the decision to meter export (in addition to import) rests on whether it is commercially advantageous. Those suppliers that have an interest in SSEG tend to calculate whether it is worthwhile the generator installing non-interval export metering when they take on a customer.

If such metering is expected to be worthwhile, an approved meter capable of recording aggregate export must be installed (an interval meter can, of course, always be installed, but the expense of this considerably greater). The export meter or register is then typically read at the same times as the import meter.

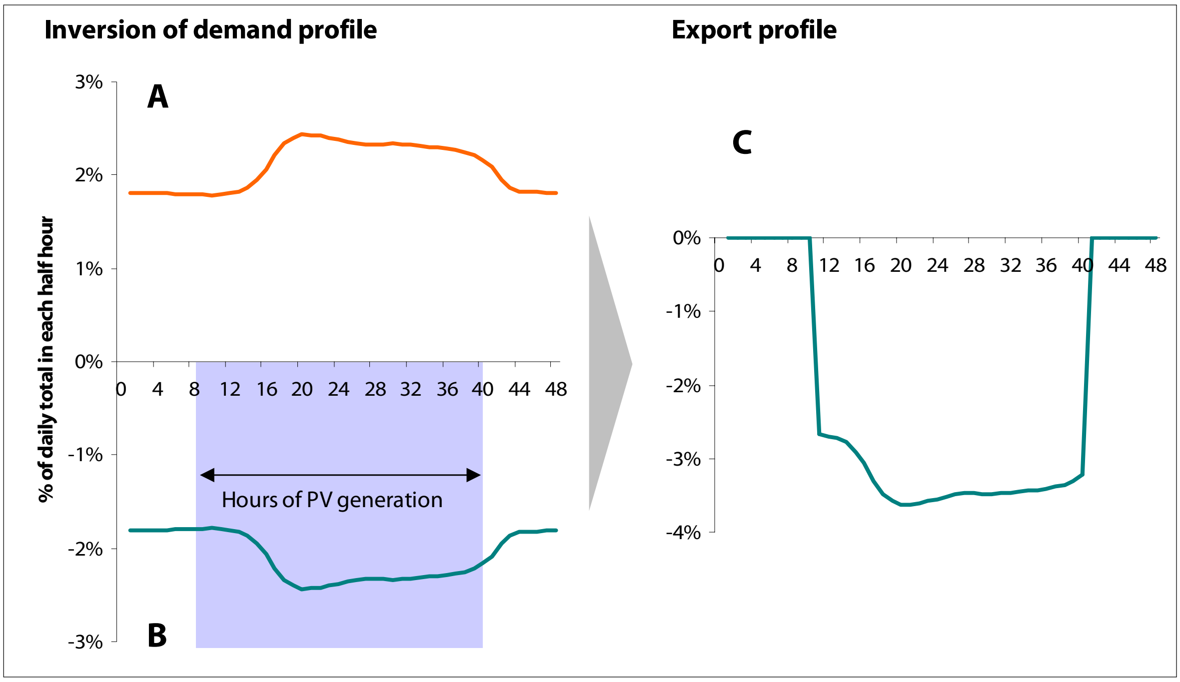
Meter and installation costs are borne by the generator, either as a one-off cost at the time of installation or recouped over time.

Aggregate import and export data is then input to the settlement system. The import is settled on a standard demand profile. It is our understanding that producing new demand profiles to take account of the impact of SSEG was considered too costly to be worthwhile. Exports from SSEG are aggregated by technology type, and settled on technology-specific profiles.

The profiles used are based on profile Class 8, the profile used for customers with maximum demand metering and a load factor of greater than 40%, but inverted (to take account of the direction of the flow of energy) and 'chunked' into the periods when each technology type typically generates. The chunking for each technology is estimated at present, but is currently the subject of research by the British Electrotechnical and Allied Manufacturers' Association (BEAMA). Improved chunking based on this research is expected to begin coming into use this year.

Figure 20 illustrates how the profile for PV is constructed, beginning with the Class 8 profile (A), inverting it (B) and chunking it into the periods in which PV is assumed to operate in GB (C). The profile is chunked at different times in winter than in summer, to account for seasonal variations. The result is a fairly crude approximation of the likely export from sites with PV SSEG. The approximation is poor because the profile assumes that the times of greatest export are also the times of greatest demand.

Figure 20 – Illustrative diagram of chunked profiling process



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